Minimizing Equipment Failures in Rod Pumped Wells

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Abstract: Equipment failure and it's attendant costs are extremely important in today's petroleum industry. Since Rod Pumping is the predominant means of artificial lift, minimizing equipment failure in rod pumped wells can have a significant impact on profitability. This paper addresses recommendations which have proven successful in the majority of wells. These have been developed within ARCO over the past 25 years and include equipment selection and design, operation and chemical treatment. The ultimate goal is to address and solve problems on a well by well basis.

Introduction: In Rod Pumping installations, premature equipment failures are usually the result of one or more of the following causes:

* Design deficiencies
* Improper selection of material (Material deficiencies)
* Manufacturing deficiencies
* Errors in assembly
* Service conditions which were not considered in design

Failure control in it's simplest form is failure analysis with the goal of achieving corrective action. This paper is a compilation of recommendations which have been learned from field locations throughout the United States and Foreign locations.

1. Data - Minimizing equipment failures requires a tracking system that identifies the failures by type (rod, tubing, pump, etc.), location (pin, body, barrel, plunger, etc.) and cause (abrasion, stuck, corrosion, split, plugged, etc.). With this data base the failures can be trended indicating the overall performance with time. Trending helps provide for comparison between producing areas. Analysis of the data will point out problems with the chemical treatment program, or particular problems associated with a specific equipment component, such as balls and seats; whether the rod failures are body or end (pin or coupling); whether the tubing leak is due to corrosion caused hole or a rod-wear caused split. Periodic meetings to discuss "problem wells" (those wells with premature failures) helps to provide guidance and reduce the number of failures. ARCO collects data using the form shown in Attachment 1[1].

A "problem well" has had premature failures as defined by the following:

* a pump failure in less than 12 months, or

* a tubing failure in less than 12 months, or

* two rod failures (pin, coupling, body) in the last 12 months, or

* has a combination of any three failures in the last 12 months, for example - a pump failure, a polished rod failure and a rod break in the last twelve months.

2. Chemical Treatments - Chemical treatments for corrosion control should be reviewed and revised as needed every 3-6 months. The need to treat, the treatment and the treating schedule should be based on factors such as failure performance, daily production, well depth, fluid levels, etc. Treating programs should consider the following key points:

* Attempt to standardize on one corrosion inhibitor for downhole use over the entire lease.

* A typical corrosion inhibitor batch treatment consists of 1 gallon of inhibitor per week for each 100 BFPD, which is equal to approximately 30 ppm on a continuous basis. If the batch treatment chemical volume exceeds five gallons of inhibitor per treatment, then the volume should be divided into two treatments per week. These concentrations are a starting point and should be optimized based on performance. Continuous treatments should be considered when the fluid production exceeds 1000 BPD. Continuous chemical injection is equipment intensive and should be used only when no other choice exists.

* Flush is extremely important. A corrosion inhibition treatment typically consists of pre-wetting the casing (typically 1 barrel),

pumping the corrosion inhibitor, then flushing with volume of 1/2 barrel/1000' (2 barrel minimum). Oil always is the best flush.

* Producing wells in CO_2 miscible injection projects should be flushed with oil when the CO_2 content of the gas exceeds 20%.

* Wells with high fluid levels consist of oil in the top 2/3 of the fluid column and the bottom 1/3 as oil and water. Circulation after batch treating is always a good idea especially on high fluid level wells, and always on the first treatment following the well having been pulled.

3. Oxygen must be kept out of the system - Provision should be made to keep oxygen from entering the annulus during normal operation and batch treating operations; keep the annulus closed. Care should be taken to minimize oxygen in the flush water used in corrosion inhibition treatments. Oxygen in the flush water will reduce the effectiveness of the inhibition treatment. Water should be obtained from gas blanketed tanks, or should be treated with an oxygen scavenger at the time the water is picked up.

4. Pretreating rods - High fluid velocity in the tubing during pumping operations may make it difficult to establish a corrosion inhibitor film as evidenced by pitting on the rod boxes and on top of the rod guides. Also, special care should be taken to re-apply the corrosion inhibitor film destroyed whenever a well is pulled. Therefore, 5 gallons of inhibitor should be placed into the tubing prior to running the pump and rods. Circulate one tubing volume when the well is returned to production.

For wells which are difficult to inhibit, the normal batch treatment should be supplemented by displacing the tubing with lease oil and ten gallons of corrosion inhibitor prior to seating the pump. This treatment assures an oil/inhibitor film will be established. A similar treatment should be performed on wells which pump under a packer and therefore cannot be batch treated.

5. Methods to minimize rod / tubing wear are:

* Always anchor the tubing; justify not anchoring. Anchor as close to the pump as practical. If the anchor is more than 400' from the pump, buckling can still be a problem below the anchor; however, breathing of the tubing is eliminated above the anchor.

* Install rod guides where repeated tubing splits and/or excessive rod coupling wear occurs. Often the wear is concentrated on the bottom of the rod string where rods go into compression or in other areas where the tubing string may be deviated.

* Install four plant applied rod guides on each of the first few rods on top of the pump (minimum of 2 guided rods). Rod wear is often observed on the bottom few hundred feet of the rods due to rod and tubing buckling and rod guides in this interval will reduce wear. Guides also centralize the pull rod, thus minimizing cocking of the plunger.

* Whenever the tubing is pulled, move two joints of tubing from the bottom to the top of the tubing string to change the wear pattern. Always install replacement tubing (new or inspected) on the bottom.

* The rod string design should include several pony rods, of various lengths, at the top of the rod string with an overall length that is three times the stroke length. Each time the well is serviced move a stroke length of the pony rods from the top of the string to the bottom but above the guided rods. When all of the pony rods have been moved to the bottom, reverse the procedure moving the pony rods back to the top of the string. Moving the pony rods in conjunction with moving the tubing changes the wear pattern on the tubing.

* Install rod rotators to distribute coupling wear around the circumference of the boxes and rod guides.

* Pump as slow as practical. Wear increases as speed increases.

6. Pump specification - Because of close tolerances and high fluid velocities experienced by sucker rod pumps, selecting the proper material is often the most economical solution to corrosion and erosion failures. Deviations from basic pump specifications should be based on experience, design considerations and pump performance.

* The **basic configuration** should consider an insert pump with a top holddown utilizing a metal plunger. A top holddown pump should be the first pump type considered based on its advantages as illustrated in the Rod Pump Application Chart, Attachment 2.

* The **basic metallurgy** should consider a barrel that has a surface hardness greater than that of the plunger. The desire is to have the plunger wear rather than the barrel. The recommended basic metallurgy is as follows:

barrel - chrome plated carbon steel
plunger - sprayed metal carbon steel
balls - cobalt alloy steel
seats - tungsten carbide

* The **initial (out of the pump shop) clearance** between the barrel and the plunger should be specified by the Operator. Consider a **downhole clearance** between 0.002" and 0.003" for light oil operations and 0.005" clearance for heavy oil operations. Remember that the downhole clearance will be different from the out-of-shop clearance due to pressure and temperature affects.

* Always measure the clearance and do not rely on the fit designated by the manufacturer (fit does not take into account tolerances). API allows the following tolerances in the manufacture of barrels and plungers: barrel -- internal diameter tolerance of -0" and +0.002"; plunger -- outside diameter tolerance of -0.0005" and +0". Unless clearances are measured when selecting the plunger and the barrel, the pump could have an out-of-shop clearance that is 0.0025" greater than specified.

* Install a pump with the smallest possible clearance which provides the smallest leakage without excessive wear, taking into account the presence of solids.

7. Care and Handling of Sucker Rods - For information concerning sucker rod handling consult API Recommended Practice RP11BR(2). A few points regarding care and handling are:

* Pins need to be lubricated prior to make up. Do not use pipe dope. In corrosive service use a combination lubricant/oil soluble corrosion inhibitor (an 80% oil, 20% inhibitor mixture is recommended). Spray or dip the pins to provide a light coating. Do not pour lubricant into the boxes.

* Sucker rod threads are rolled not cut. Once the threads are damaged the threads cannot be reconditioned and the rod should be discarded.

* Power tongs are recommended for all size rods except 5/8" (Do you really want to use 5/8" rods?). Calibrate the power tongs on each well and each taper using the circumferential displacement method.

* Any coupling with evidence of being hammered or having wrench marks should be replaced.

* Lay down and pick up rods in singles.

8. Design and Operation Considerations

* For a given production consider the longest stroke and slowest speed.

* Pounding and improper spacing severely shorten equipment life. Fluid pound is the incomplete fillage of the barrel. Tapping occurs on the downstroke or upstroke due to improper spacing of the pump.

* Keeping a well pumped off and pounding doesn't necessarily mean more production. In a reservoir with a low productivity index and high reservoir pressure, as in most water floods, having 5 to 10 joints of cover above the pump will not appreciably change the production. Try it!

* Rods strings should be designed for the loads and routinely monitored via dynamometers. The range of stress should be within the Modified Goodman diagram including the appropriate service factor for the installation(2).

* Design using a predictive program for design should always be compared to an actual card to ensure the rods and unit are within acceptable parameters. Always check the design under real world conditions.

* Consider reversing the order in which the rods operate within a taper (top rod to bottom of taper; bottom rod to top of taper). This could be done once a year or at the five million reversals criteria.

* Whenever possible, dynamometer the well following an operational change, such as a change in the pump size, speed, stroke length, etc.

9. Surface corrosion coupons and rod pumping - It is easy to fall in the trap of believing that surface coupons represent the corrosive environment downhole. There are at least four reasons why surface corrosion coupons will not be indicative of the downhole corrosion rate.

* A typical corrosion treatment consists of a weekly batch treatment. Soon after the corrosion inhibitor films, it starts being removed by the produced fluids. The bottom of the rod string can be void of an inhibitor film while the surface corrosion coupon is still being inhibited.

* A corrosion coupon does not show corrosion that is accelerated by wear. Metal loss can be accelerated in even mildly corrosive environments by continuously removing the corrosion byproducts.

* A well that is intermittently pumped will have oil and water separation in the well bore. The bottom of the rod string will be in water while the surface corrosion coupon sees oil.

* The pressure at the surface and downhole are substantially different; therefore, the partial pressure of carbon dioxide and hydrogen sulfide will be much greater downhole.

Rather than using corrosion coupons, look at the rods when they come out of the well. Is there evidence of corrosion, i.e. pitting? Do the rods stay black (i.e. good inhibitor film) while hanging in the derrick or do they turn red and rust (i.e. no inhibitor film)? The real indicator of the corrosive nature of a well is the type of failures and their frequency.

10. Rod replacement practices - Don't replace the rod string one rod at a time. Although this appears to be reducing cost, it actually costs more money when pulling cost is considered. When the pulling cost due to rod failures exceeds the cost of a new rod string within a short period of time, then the rods should be replaced. Typically, when a well has had three rod failures within a two year period then the rod string should be replaced on the fourth failure. If the rod failures are all within a taper, change out only that section of rods.

11. Failure analysis - Good records are critical to failure analysis. Do not replace failed equipment in-kind; always analyze the failure in order to determine the cause. Look at the rods, tubing, pumps, witness pump teardowns, and then take the appropriate corrective action based on the result of the failure analysis. Keep good records - intentions are good but memories are short.

Conclusions - The results of using this system has resulted in an improvement in equipment performance in ARCO's lower 48 operations. Comparing the mean time between failures for 1970 and 1988 the following improvement in equipment life has been documented:

type of failure	1970	1988
rods	20 months	75 months
rod pumps	20 months	40 months
tubing	60 months	100 months

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References

(1) Bucaram, S. M., and B. J. Yearly: "A Data-Gathering System to Optimize Producing Operations: A 14 Year Review," JPT (April, 1987) 457-62; Trans. AIME, 287

(2) API Recommended Practice 11 BR: "Recommended Practice for Care and Handling of Sucker Rods."

ATTACHMENT 1

Equipment Performance Report: Subsurface

Lease or unit name:

(1-2) 0 4 | (3-4) (5-11) Lease Accounting Code | (12-15) Sub

(16-18) Tract or section | (19-22) Well | (23-24) Date Mo. | (25-26) Day | (27-28) Yr. | (29-33) Depth of failure in feet or in number of joints from surface.

Note: Enter code numbers in squares above column (no code number, leave squares blank). (Explain) in squares labelled "Remarks".

Type of well (34-35)

	NON	None
01	FO	Flowing oil
02	FG	Flowing gas
03	GL	Gas lift
04	PMP	Pumping (Rod, Hyd Piston, Hyd Jet, Submersible)
05	WI	Water injection
06	GI	Gas injection
07	WS	Water supply
08	WD	Water disposal
09	PLL	Plunger lift
10	ROT	Rotary
11	SI	Steam Injection

Type of service (36-37)

	OTH	Other
01	ACD	Acidize/stimulate well *
02	FRC	Frac well *
03	WWR	Well workover
04	LTS	Test - log
06	ABA	Abandon
08	STM	Steam soak
09	PSI	Pressure survey
10	INH	Inhibit well
11	CAL	Caliper well
12	RES	Resizing pump

* **Note: If stimulating, please complete Stimulation Section (below). Please record costs.**

Failing equipment (38-39)

	NON	None
01	PMP	Rod pump
02	PMH	Hydraulic pump, piston
22	PMJ	Hydraulic pump, jet
03	ESP	Submersible pump
04	ROD	Rod
05	ROP	Rod failure, which caused pump damage
06	TBG	Tubing
07	TBF	Tubing failure, which caused pump damage
08	CSG	Casing
10	PKR	Packer
11	BJT	Blast joint
12	PRD	Polish rod or liner (explain which)
14	GLV	Gas lift valve
16	MDR	Mandril
21	SSV	Safety valve
23	PLL	Plunger or catcher or stop
24	SNP	Seating nipple
25	STV	Standing valve
26	BHA	Bottom hole assembly, cavity
30	OTR	Other (explain)

Type of failure (40-41)

	NON	None
01	HOL	Hole
02	BRK	Break
03	STK	Stuck
04	SPT	Split or crack
05	PLG	Plugged
06	LEK	Leak, water in motor
15	WSH	Washed
07	DEF	Worn, deformed or collapsed
08	UNS	Unscrewed
13	COT	Plastic coating disbondment
14	ELC	Electrical
10	OTR	Other (explain)

Location of failure (42-43)

	NON	None
01	BDY	Body
02	PIN	Pin
03	CLP	Coupling
04	THD	Thread
05	UPS	Upset
21	UUP	Upper upset or wrench flat
06	PLN	Plunger
07	BRL	Barrel
08	VBS	Valve, balls, seats
09	CUP	Cups
10	PMP	Entire pump damaged
11	SEL	Seal
31	JNF	Jet nozzle (HYD)
32	JTH	Jet throat (HYD)
14	ENG	Engine end (HYD)
15	PRE	Production end (HYD)
16	STV	Standing valve (HYD)
17	EAP	Engine and production end (HYD)
19	PPR	Pump pull rod
20	PHD	Pump holdown
22	ESP	Pump end (ESP)
23	ESG	Gas separator (ESP)
24	ESS	Seal section (ESP)
25	ESM	Motor (ESP)
26	ESX	Motor lead extension (ESP)
27	ESH	Pot head (ESP)
28	ESC	Power cable (ESP)
30	OTH	Other (explain)

Cause of failure (44-45)

	NON	None
01	WER	Wear
02	ABR	Abrasion, fluid cut
03	COR	Corrosion
04	FAT	Fatigue
05	SND	Sand
06	MUD	Mud
07	SCL	Gyp or scale
08	PAR	Paraffin
09	RUB	Rubber (in the pump)
10	MET	Metal (in the pump)
12	IPA	Improper application
13	IPH	Improper handling
14	UNK	Unknown
15	CRH	Crooked hole
18	ELC	Electrical, lightning
17	OTR	Other (explain)

MFG (46-47)

	Not applicable
01	Axelson (rods)
02	UPCO (rods)
03	Continental - EMSCO (rods)
04	Norris (rods)
05	Oilwell (rods)
06	Tuboscope (coating)
07	BTS (coating)
08	Spincote (coating)
09	VETCO (coating)
10	Reda (ESP)
11	Centrilift - Hughes (ESP)
12	ODI (ESP)
13	Trico (ESP)
14	Baker - Lift (ESP)
15	Other (ESP)

Stimulation Section

Reason For (48)

1. Fines/clays
2. Mud damage
3. Scale
4. Bacteria
5. Emulsion
6. Paraffin/ asphaltenes
7. Water block
8. Water reduction
9. Initial completion or other (explain in remarks)

Company Used (49)

1. BJ
2. Dowell
3. Halliburton
4. Baker
5. Western
6. Acid Eng.
7. SERFCO
8. Smith Energy
9. Other (explain in remarks)

If chemical stimulation

Type (50)

1. HCl:HF
2. HCl
3. Acetic
4. Bleach
5. Solvent
6. Scale Squeeze
7. Other (explain in remarks)

Type Acid (51)

1	HCl:HF	12:3%
2	HCl:HF	6:1.5%
3	HCl:HF	6:0.5%
4	HCl	28%
5	HCl	20%
6	HCl	15%
7	HCl	10%
8	HCl	7.5%
9	Acetic	10%

(52-56) If chemical stim: volume - Gals. If Frac: Frac Fluid Vol - Bbls

(57-60) If Frac: Frac Sand weight - M pounds

Cost - dollars only (Round cost to nearest dollar)

(61 → 66) Pump only | (67 → 73) All equipment other than pumps. | (74 → 80) All labor costs: Company + Contract + Workover + Stimulation + Other

(1 ← 5 10 15 20 25 30 35 40)

Remarks (left justified, Please print): For permanent record enter information in remarks squares.

41 ← 45 50 55 60 65 70 75 80)

Remarks (continuation)

(1 ← 5 10 15 20 25 30 35 40)

Remarks (continuation)

41 ← 45 50 55 60 65 70 75 80)

Remarks (continuation)

ATTACHMENT 2

Rod Pump Application Chart

	sand	scale	depth > 7000'	intermittent pumping	corrosion	large volumes	low fluid level	gas	low speed	paraffin
rod pump traveling barrel bottom holddown	✔	✔	✔	✔✔	✖	✔	✖	✖	✔	✔
rod pump stationary barrel bottom holdown	✖	✔	✔✔	✔	✖	✔	✔	✔	✔	✔
rod pump, stationary barrel top holddown	✔✔	✔	✖	✔	✔✔	✔	✔✔	✔✔	✔	✔
rod pump 3 - tube	✔✔	✔	✖	✔✔	✖	✖	✖	✖	✖	✔
stroke through	✔✔	✔✔						✖		✔✔
tubing pump	✔	✔	✖	NA	✔✔	✔✔	NA	✖	✔	✔
casing pump	✖	✖	✖	NA	✖	✔✔	NA	✖	✔	✖

✔✔ - better, ✔ - good, ✖ - not recommended, NA - not applicable