IMPLEMENTING AI POCS AND THE ADVANTAGES OF NON-FIXED STROKE LENGTH ROD PUMPING SYSTEMS

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INTRODUCTION

Recent advancements in artificial intelligence (AI) for pump-off controllers (POCs) have significantly improved the ability to remotely identify abnormal pumping conditions in rod lift systems. These systems can now detect issues such as gas interference, pump tagging, fluid pound, and stuck pumps with a high degree of accuracy. However, a major limitation remains. While AI can identify problems, most conventional rod pumping units lack the mechanical capability to autonomously implement corrective actions. Due to fixed geometry and stroke constraints, field intervention is typically required. This paper presents the integration of AI-driven POCs with non-fixed stroke length rod pumping systems, enabling automated corrective actions without field intervention.

BACKGROUND AND PROBLEM STATEMENT

Enhancements in drilling technologies have resulted in increasingly complex wellbores capable of higher production in early life. As these wells deplete and conversion to rods become necessary, these complex well bores result in higher failure frequencies and increased downtime. Conventional beam pumping units operate within fixed geometric constraints including fixed stroke length, limited speed control, and inability to reposition rods dynamically (figure 1). These limitations create a disconnect between AI diagnostics and physical response, often requiring human intervention through operators, service rigs, or other third-party equipment.

TECHNOLOGY OVERVIEW

Non-fixed stroke length rod pumping systems introduce full control over rod movement including variable stroke length, independent stroke speeds, and programmable sequences. These capabilities allow automated execution of corrective actions that traditionally require manual intervention (figure 2).

METHODOLOGY

Field-proven manual intervention techniques were replicated using automated surface unit control integrated with AI POCs. The process includes detection of abnormal conditions, decision-making through programmed logic, and execution through dynamic stroke adjustment (figure 3).

FIELD CASE STUDIES

Case Study 1. Gas Interference

Figure 4. Illustrates the before and after comparison of two surface and downhole cards before and after the AI has identified a gas interference condition. The controller manipulated the bottom stop position on the surface equipment, lowering the rods ten inches. The result was an increase in pump fillage from 34% to 52%. The total sequence was automated resulting in zero downtime or lost production. Based on the installed rod design figure 5. and $70 per barrel oil price the below comparison can be assumed.

Economic Impact Comparison (217 BOPD (100%) $70/bbl.)

Metric	Example 1: Fixed Stroke Length	Example 2: Non-Fixed Stroke
Pump Fillage	34%	52%
Total Actual BOPD	73.78	112.84
Total Revenue (per day)	$5,164.60	$7,898.80
Total Revenue Added (per day)	—	$2,734.20

Case Study 2. Tagging Pump

Figure 6. Illustrates the before and after comparison of two surface and downhole cards before and after the AI has identified a downhole pump tag condition. The controller manipulated the bottom stop position on the surface equipment, raising the rods by four inches. The result was eliminating the downhole pump tag and preventing further damage to the downhole pump. The sequence was automated resulting in zero downtime or lost production. Based on the installed rod design figure 7. and $70 per barrel oil price the below comparison can be assumed.

Economic Impact Comparison (100 BOPD $70/bbl.)

Metric	Example 1: Manually Adjust Clamps	Example 2: Non-Fixed Stroke
Intervention Cost (Manal/Automated)	$900 (4 hrs. $225)	—
Downtime Hours	4 Hours	—
Deferred Revenue (Lost Production)	$1,167	—
Total Revenue Lost	$2,067	—
Total Potential Savings		$2,067

Case Study 3. Sticking on Downstroke

Figure 8. Illustrates the before and after comparison of two surface cards before and after the AI has identified a rod fall issue. The controller manipulated the stroke length by turning around mid-downstroke when the measured load dropped below the allowable MPRL based on the rod design. This prevented the rods being put into compression, eliminating potential carrier bar separation or a shut-down due to a no-load condition. Subsequent strokes were completed at full length. The sequence was automated resulting in zero downtime or lost production. Based on the installed rod design figure 9. and $70 per barrel oil price the below comparison can be assumed.

Economic Impact Comparison (534 BOPD $70/bbl.)

Metric	Example 1: Low Load Shutdown (Evening)	Example 2: Non-Fixed Stroke
Downtime Hours	8 Hours	—
Deferred Revenue (Lost Production)	$12,460	—
Total Potential Savings (per shutdown)		$12,460

Case Study 4. Stuck Downhole Pump

A Glasscock County producer converted a well from ESP to Rods. After the well intervention, a non-fixed stroke length rod pumping unit was installed. During start up, the unit operated for approximately 30 minutes before becoming stuck downhole. 75 Barrels of hot oil were pumped down the annulus and circulated for 60 mins. The non-fixed stroke length pumping unit was then used in place of a service rig to pull and relax the rods until the downhole pump started to travel. Automated sequencing then took over, extending the stroke length three inches per stroke until a full stroke length was achieved. The unit was returned to service and produced as per design. Consider the operational cost comparison between the above procedure and a service rig intervention. Based on the installed rod design in figure 10. and $70 per barrel oil price, the below comparison can be assumed.

Economic Impact Comparison (225 BOPD $70/bbl.)

Metric	Example 1: Service Rig	Example 2: Non-Fixed Stroke
Intervention Cost (Rig/Hot-Oiler)	$30,000	$3,400
Downtime Hours	72 Hours	4 Hours
Deferred Revenue (Lost Production)	$47,250	$2,625
Total Revenue Lost	$77,250	$6,025
Total Potential Savings	—	$71,225

RESULTS AND DISCUSSION

In each case, the system successfully resolved issues without service rig intervention and with minimal manual input. The ability to dynamically manipulate stroke length resulted in reduced downtime, improved production, and lower operating costs. Automated responses significantly reduced the time required to correct abnormal conditions. Additionally automated responses eliminate unnecessary exposure hours resulting in an inherently safer producing well.

ROLE OF AI IN AUTOMATION

AI POCs provides accurate detection, while non-fixed stroke systems enable the execution of corrective actions. This integration allows for fully automated response systems in rod lift operations.

LESSONS LEARNED

Mechanical flexibility is essential to maximize AI value. Many failures can be resolved without rigs, reducing downtime and cost. System design must consider both AI capability and mechanical execution.

PRACTICAL APPLICATION GUIDELINES

Non-fixed stroke length systems provide the greatest value in wells with:

- High intervention costs
- Frequent pump-related failures
- High production sensitivity to downtime
- Complex wellbore geometries
- Gas interference or spacing challenges

CONCLUSIONS

Non-fixed stroke length systems enable AI-driven automation in rod lift operations, reducing downtime and costs while increasing production. This approach represents a significant step toward autonomous artificial lift systems.

END NOTES

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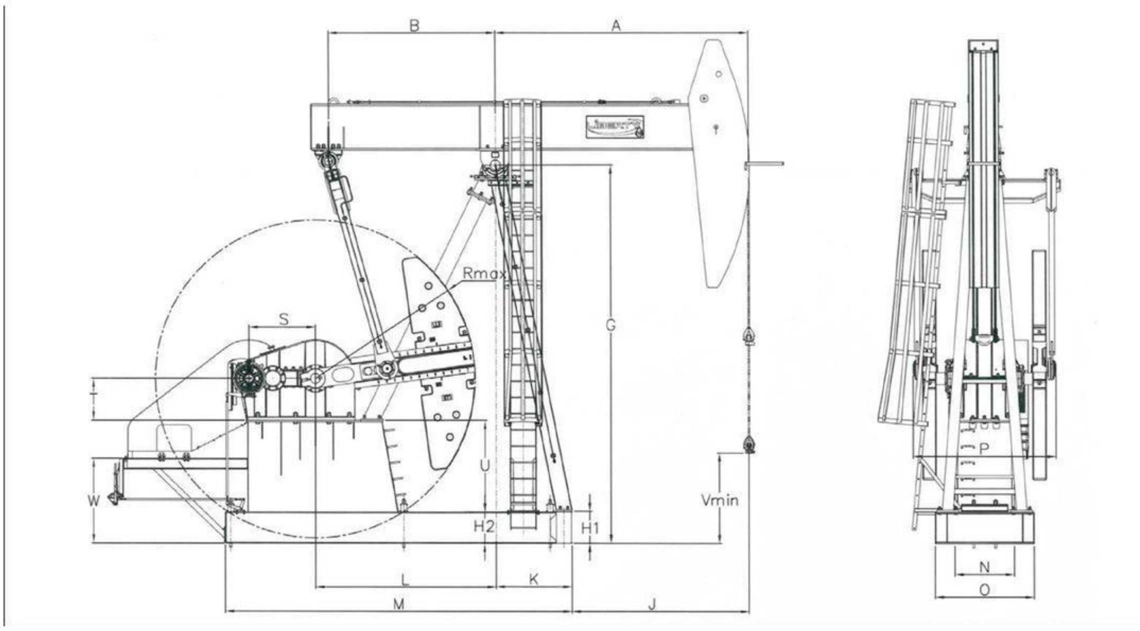

Figure 1.

Figure 2.

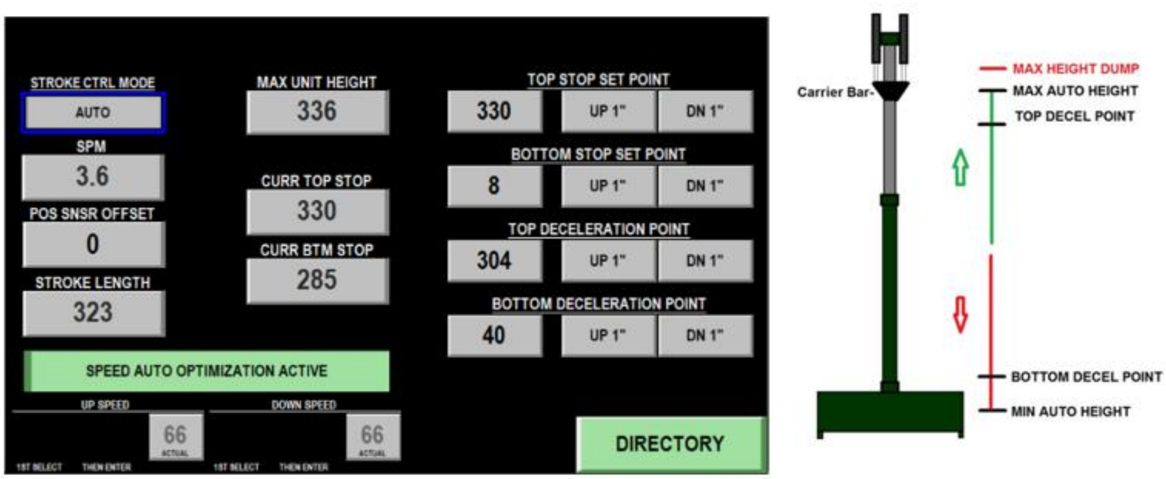

Figure 3.

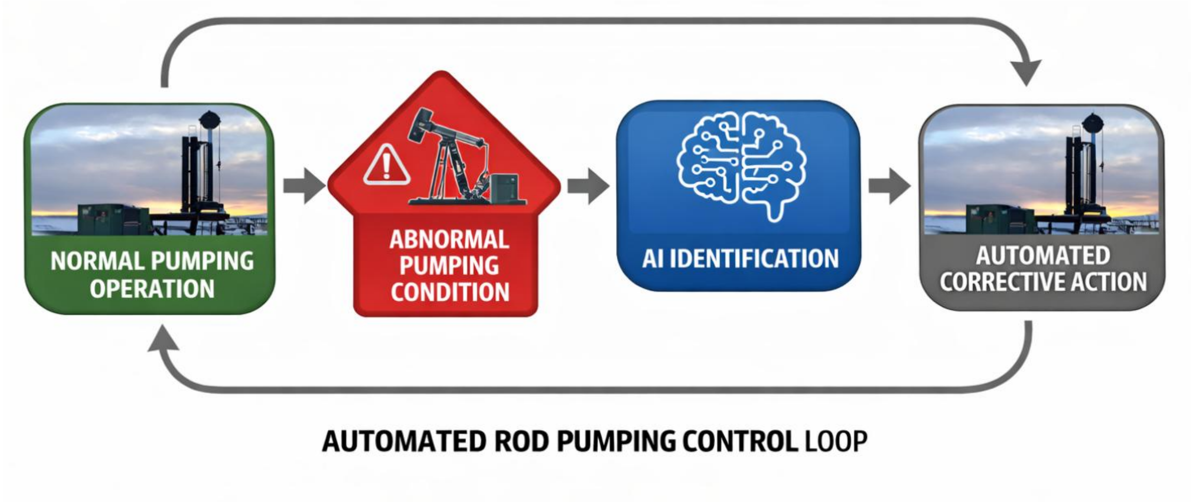
NORMAL PUMPING OPERATION
ABNORMAL PUMPING CONDITION
AI IDENTIFICATION
AUTOMATED CORRECTIVE ACTION
AUTOMATED ROD PUMPING CONTROL LOOP

Figure 4.

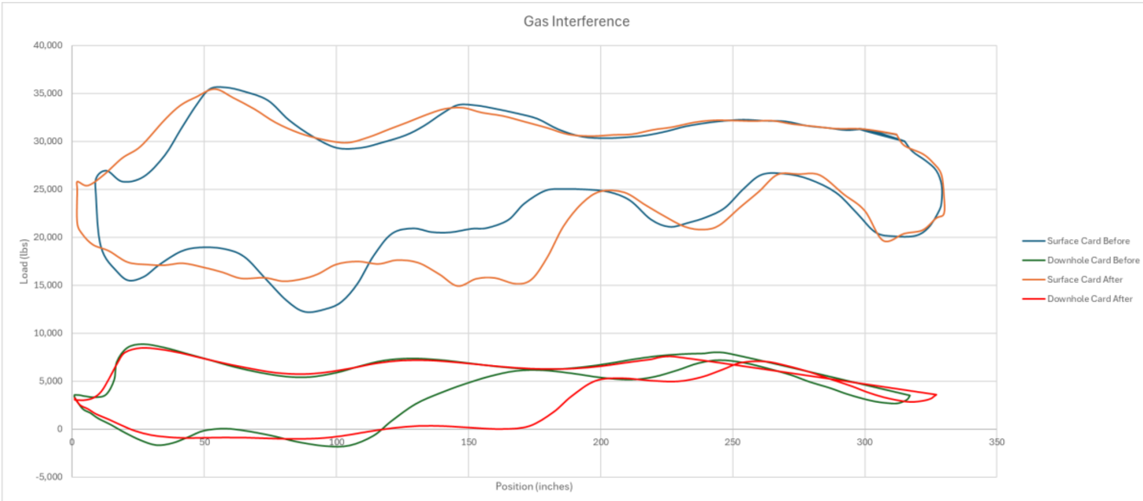

Figure 5.

INPUT DATA			
Strokes per minute:	4	Fluid level	
Run time (hrs/day):	24.0	(ft from surface):	7540
Tubing pres. (psi):	350	(ft over pump):	0
Casing pres. (psi):	100	Stuf.box fr. (lbs):	100
		Pol. rod. diam.	1.5"

Fluid Properties		Motor & Power Meter	
Water cut:	50%	Power meter	Detent
Water sp. gravity:	1.05	Elect. cost:	$.06/KWH
Oil API gravity:	40.0	Type:	NEMA D
Fluid sp. gravity:	0.9375		

Pumping Unit:Tundra SSi Hydraulic

Unit Size: H-400-336 (Unit ID: HSS15)

Crank hole number:	N/A
Calculated stroke length (in):	336
Crank rotation	N/A
Max. cb weight	N/A
Measured Stroke Length (inch):	336

Tubing And Pump Information

Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	7540	Tub.anch.depth (ft):	7440
Pump conditions:	Full		
Pump type:	Insert	Pump vol. efficiency:	75%
Plunger size (in):	2	Pump friction (lbs):	200.0

CALCULATED RESULTS (TOTAL SCORE: 95% GRADE: A)			
Production rate (bfpd):	433	Peak pol. pod load (lbs):	33614
Oil production (BOPD):	217	Min. pol. rod load (lbs):	10505
Strokes per minute:	4	MPRL/PPRL:	0.313
System eff. (Motor->Pump):	40%	Unit struct. loading:	84%
Permissible load HP:	135.8	PRHP / PLHP:	0.35
Fluid load on pump (lbs):	10251		
Fluid level tvd (ft from surface):	7423	Buoyant rod weight (lbs):	17132
Polished rod HP:	47.4	N/No: .121 ,	Fo/SKr: .132
Required prime mover size (speed var. not included)	BALANCED (Min Torq)		
NEMA D motor:	75 HP		
Single/double cyl. engine:	60 HP		
Multicylinder Engine:	75 HP		

Torque analysis and electricity consumption	BALANCED (Min Torq)
Peak g'box torq.	N/A
Gearbox loading:	N/A
Cyclic load factor:	N/A
Counterbalance weight	N/A
Daily electr.use (Kwh/Day):	1020
Monthly electric bill:	$1866
Electr.cost per bbl fluid:	$0.141
Electr.cost per bbl oil:	$0.282

Tubing, Pump And Plunger Calculations	
Tubing stretch (in):	.2
Prod. loss due to tubing stretch (bfpd):	0.3
Gross pump stroke (in):	310.1
Pump spacing (in. from bottom):	22.6
Minimum pump length (ft):	38.0
Recommended plunger length (ft):	6.0

Figure 6.

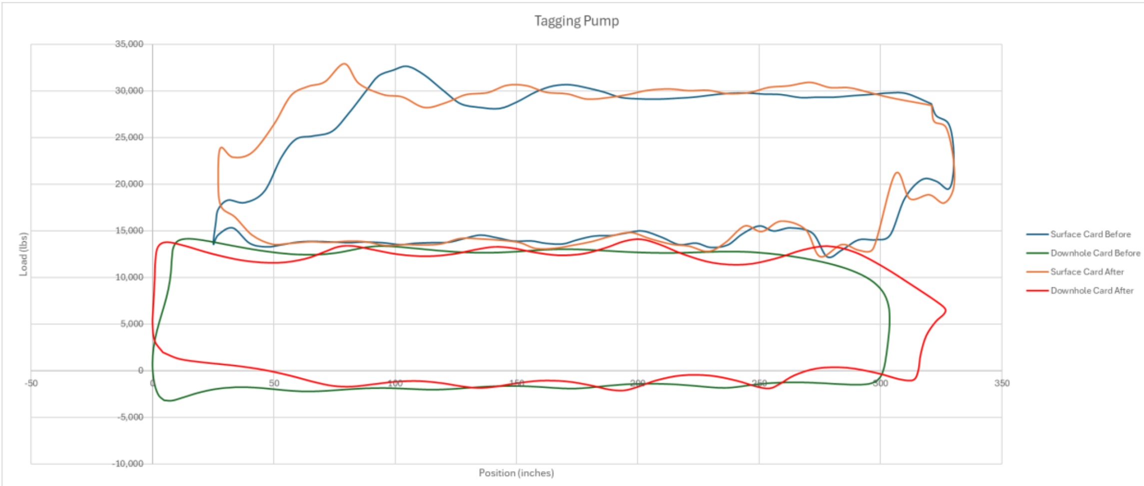

Figure 7.

INPUT DATA			
Strokes per minute:	4	Fluid level	
Run time (hrs/day):	24.0	(ft from surface):	6200
Tubing pres. (psi):	100	(ft over pump):	25
Casing pres. (psi):	200	Stuf.box fr. (lbs):	100
		Pol. rod. diam.	1.5"

Fluid Properties		Motor & Power Meter	
Water cut:	80%	Power meter	Detent
Water sp. gravity:	1	Elect. cost:	$.06/KWH
Oil API gravity:	35.0	Type:	NEMA D
Fluid sp. gravity:	0.97		

Pumping Unit:Tundra SSi Hydraulic

Unit Size: H-400-336 (Unit ID: HSS31)

Crank hole number:	N/A
Calculated stroke length (in):	336
Crank rotation	N/A
Max. cb weight	N/A
Measured Stroke Length (inch):	336

Tubing And Pump Information

Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	6225	Tub.anch.depth (ft):	5550
Pump conditions:	Full		
Pump type:	Insert	Pump vol. efficiency:	85%
Plunger size (in):	2	Pump friction (lbs):	1000.0

CALCULATED RESULTS (TOTAL SCORE: 93% GRADE: A)

Production rate (bfpd):	500	Peak pol. pod load (lbs):	34907
Oil production (BOPD):	100	Min. pol. rod load (lbs):	9040
Strokes per minute:	4	MPRL/PPRL:	0.259
System eff. (Motor->Pump):	35%	Unit struct. loading:	87%
Permissible load HP:	135.8	PRHP / PLHP:	0.39
Fluid load on pump (lbs):	7628	Buoyant rod weight (lbs):	17133
Fluid level tvd (ft from surface):	6018	N/No: .101 ,	Fo/SKr: .063
Polished rod HP:	52.7		

Required prime mover size (speed var. not included)	BALANCED (Min Torq)
NEMA D motor:	75 HP
Single/double cyl. engine:	75 HP
Multicylinder Engine:	75 HP

Torque analysis and electricity consumption	BALANCED (Min Torq)
Peak g'box torq.	N/A
Gearbox loading:	N/A
Cyclic load factor:	N/A
Counterbalance weight	N/A
Daily electr.use (Kwh/Day):	1126
Monthly electric bill:	$2061
Electr.cost per bbl fluid:	$0.135
Electr.cost per bbl oil:	$0.675

Tubing, Pump And Plunger Calculations

Tubing stretch (in):	1.2
Prod. loss due to tubing stretch (bfpd):	1.8
Gross pump stroke (in):	316.7
Pump spacing (in. from bottom):	18.7
Minimum pump length (ft):	36.0
Recommended plunger length (ft):	5.0

Figure 8.

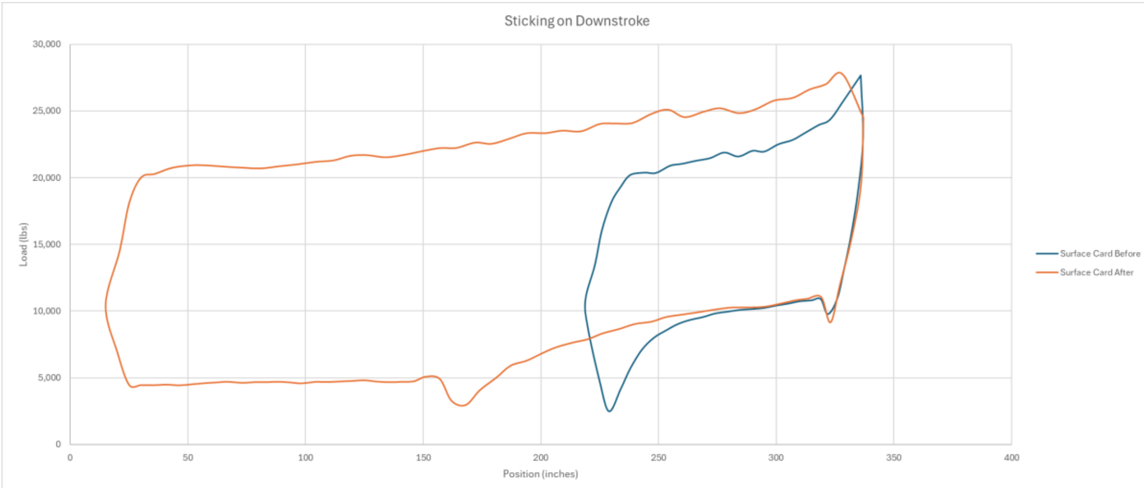

Figure 9.

** POWER UNIT **

SSi 200 HP Hydraulic Power Unit

Est. Power Required (hp)	: 191.5	Motor Load (% of Rating)	: 95.6

** PUMPING UNIT **

Hydraulic unit SSi 600

Actual Max Load (lbs)	: 31443	Actual Min Load (lbs)	: 1927
Pumping Speed (spm)	: 3.96	Max Load (% of Rating)	: 52.4
Polished Rod Power (hp)	: 65.98	Computed Surface Stroke (cm)	: 853

** ROD STRING **

	Diameter (mm)	Length (m)	Rod Type	Rod Loading	Guides (Counts/rod)
1)	50.8	80	API C	47	N (0)
2)	28.575	200	PROROD 960M	62	N (0)
3)	25.4	388	PROROD 960M	62	N (0)

Service Factor for Steel Rod	: 0.9		
Max Stress @ surface (MPa)	: 69	Min Stress @ surface (MPa)	: 4

** DOWNHOLE PUMP **

Bore Size (mm)	: 107.95	Setting Depth (m)	: 668
Tubing Stretch (cm)	: 3.8	Lost Displacement (m³/d)	: 2
Pump Intake Pressure (kPa)	: 861	Pump Spacing Guide (mm)	: N/A
Tubing Size (mm)	: 139.7	Tubing Anchor Location (m)	: 0
Tubing Gradient (kPa/m)	: 9.932	Pump Fillage %	: 80

	Stroke (cm)	M³/D at 100% eff.	M³/D at 80% eff.
Gross:	820.9	429 (24h/d)	343 (24h/d)
Net:	655.3	342 (24h/d)	274 (24h/d)

Figure 10.

INPUT DATA			
Strokes per minute:	4.1	Fluid level	
Run time (hrs/day):	24.0	(ft from surface):	7108
Tubing pres. (psi):	50	(ft over pump):	0
Casing pres. (psi):	50	Stuf.box fr. (lbs):	100
		Pol. rod. diam.	1.5"
Fluid Properties		**Motor & Power Meter**	
Water cut:	63.9%	Power meter	Detent
Water sp. gravity:	1	Elect. cost:	$.06/KWH
Oil API gravity:	35.0	Type:	NEMA D
Fluid sp. gravity:	0.9458		

Pumping Unit:Tundra SSi Hydraulic	
Unit Size: H-400-336 (Unit ID: HSS15)	
Crank hole number:	N/A
Calculated stroke length (in):	336
Crank rotation	N/A
Max. cb weight	N/A
Measured Stroke Length (inch):	336

Tubing And Pump Information			
Tubing O.D. (in):	2.875	Upstr. rod-fl. damp. coeff.:	0.100
Tubing I.D. (in):	2.441	Dnstr. rod-fl. damp. coeff.:	0.100
Pump depth (ft):	7108	Tub.anch.depth (ft):	7108
Pump conditions:	Full		
Pump type:	Tubing	Pump vol. efficiency:	85%
Plunger size (in):	2.25	Pump friction (lbs):	200.0

CALCULATED RESULTS (TOTAL SCORE: 35% GRADE: F)			
Production rate (bfpd):	624	Peak pol. pod load (lbs):	38115
Oil production (BOPD):	225	Min. pol. rod load (lbs):	9339
Strokes per minute:	4.1	MPRL/PPRL:	0.245
System eff. (Motor->Pump):	42%	Unit struct. loading:	95%
Permissible load HP:	139.2	PRHP / PLHP:	0.45
Fluid load on pump (lbs):	11270	Buoyant rod weight (lbs):	16118
Fluid level tvd (ft from surface):	6921	N/No: .119 ,	Fo/SKr: .14
Polished rod HP:	63.1		
Required prime mover size (speed var. not included)	BALANCED (Min Torq)		
NEMA D motor:	100 HP		
Single/double cyl. engine:	100 HP		
Multicylinder Engine:	100 HP		
Torque analysis and electricity consumption	BALANCED (Min Torq)		
Peak g'box torq.	N/A		
Gearbox loading:	N/A		
Cyclic load factor:	N/A		
Counterbalance weight	N/A		
Daily electr.use (Kwh/Day):	1327		
Monthly electric bill:	$2429		
Electr.cost per bbl fluid:	$0.128		
Electr.cost per bbl oil:	$0.354		

Tubing, Pump And Plunger Calculations	
Tubing stretch (in):	.0
Prod. loss due to tubing stretch (bfpd):	0.0
Gross pump stroke (in):	303.4
Pump spacing (in. from bottom):	21.3
Minimum pump length (ft):	39.0
Recommended plunger length (ft):	6.0