TIMER CONTROL OF BEAM PUMP RUN TIME REDUCES OPERATING EXPENSE

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Introduction

More than 400,000 wells in the United States operate with beam pump artificial lift equipment. Most of these wells have a pump capacity that exceeds the production rate of the well. Also, most of these wells pump 24 hours per day. These wells would operate more efficiently and at a lower cost with a device that reduces the amount of pumping unit operating time. This reduction in operating time decreases both electricity and maintenance costs.

Fluid flows into the wellbore when the pressure at the bottom of the wellbore is less than the pressure in the reservoir. In beam pumped wells, this liquid in the wellbore is removed by a reciprocating pump which has a capacity that is a function of pump size, pump stroke length, pumping speed, run time and other factors. In most beam pumped wells, the pump capacity exceeds the liquid producing capacity of the well. Therefore, the pump could be operated periodically and yet the pump would remove practically all of the liquid from the wellbore. While the well is shut-in, however, the pressure at the bottom of the well should be maintained at a low value compared to the reservoir pressure so that maximum inflow[1] into the wellbore will occur. It is important, when producing a well on intermittent operation, that the liquids above the formation and the bottomhole pressure be maintained at low values so that the desired maximum inflow of liquid into the wellbore will occur.

Wells that operate 24 hours per day and have a pump capacity in excess of the well's producing rate "pound" liquid during the pump down stroke. This "pounding" of the pump plunger against the liquid causes vibration throughout the entire pumping system. The shock loading can cause rod buckling, pump wear, tubing wear, severe rod loading changes and pumping unit vibration even to the extent that the vibration can be visually observed and oftentimes even heard. These changes in loading are easily measured using a dynamometer system. Changes in rod loading on the downstroke also affect the pumping unit balance and motor power requirements. Longer life will be experienced by the pump, rods, tubing and pumping unit system if the plunger does not "pound" liquid near the middle of the down stroke. Operating the pumping system with a pump barrel full of liquid will result in longer equipment life.

This paper discusses various methods of controlling the operating time of electrically driven beam-pumped systems where the pump capacity exceeds the liquid producing capacity of the well. Two types of devices are commonly used to control pumping unit run time. An electrical manually-set on/off timer can be used to control when the pumping unit motor operates. Or, an automatic pump-off-control (P-O-C) device can monitor a parameter that relates to pump fillage and shut down the pumping unit motor when partial pump fillage or liquid no-flow is detected.

Pump-Off-Control Systems

A P-O-C device monitors some parameter of the pumping system. The polished rod load, motor current, pumping unit rotational speed, vibration, liquid flow, liquid level or some other parameter of the pumping system is monitored to detect when the pump is not full of liquid. The P-O-C device shuts down the pumping system when the pump is not filled with liquid. The on/off pumping cycle is as follows. First, the P-O-C stops the pumping system. The down time allows the liquid flowing from the formation into the wellbore to accumulate into the annular space between the casing and tubing above the pump. After a predetermined down time, the pumping system automatically starts and a sensor monitors some parameter relating to pump fillage. Initially, the pump should be full of liquid. Later, when the liquid in the wellbore has been produced and a reduction in pump fillage is detected, the pumping system is again shutdown to permit liquid to accumulate in the casing annulus. This cycle generally reduces the operating time and operating expense without loss of oil production. Numerous papers [2,3,4,5,6,7,8] have been written on different sensors and techniques that are used to control a pumping system by monitoring a parameter that varies with pump fillage.

A substantial advantage of a P-O-C system over continuous operation or a timer is that the well performance is monitored. With some P-O-C's, the amount and variance of run time are obtained which can indicate potential additional oil production, pump slippage and poor pump performance. Remote monitoring of the polished rod loads or other parameters allows early detection of abnormal well performance. Problems can be corrected immediately, if desired, which will result in maintaining the desired production. The main disadvantages of the P-O-C systems are the cost (between $500 and $5000 per well) and the additional personnel required to monitor the P-O-C system and each well's performance.

Many papers have been written on pump-off controllers and many patents[10] exist. These systems have been improved over the years with better sensors, electronics, software and cabling so that excellent overall performance is usually obtained. A P-O-C will reduce operating costs and electricity costs and will justify the cost of installation on appropriate wells.

Timers

A timer can also be used to control pumping unit run time. Two different types of timers[15] are commonly used in the oil field. A percentage timer controls the percentage of time that the pumping unit operates, or, an interval timer controls the time intervals (generally in 15 minute periods) that the pumping unit operates.

The timer is simple to operate and inexpensive. It can normally be installed for $200 or less. Some solid-state percentage timers[16] cost less than $25. Generally, a small step-down transformer and low voltage relay are also used which cost about $50. The main disadvantage of the timer is that the operator must correctly set the timer to operate the pumping system for the optimum amount of time. The most accurate method for determining proper run time is to use a computerized dynamometer[2] that obtains a surface dynamometer card and calculates a pump card showing pump fillage. The percentage timer should be set to run for approximately the same percentage of time as the percentage of fillage in the pump when the unit is operated continuously. Another disadvantage of the timer is that the pump condition or the well's maximum potential flow rate may change, and the pre-set timer will not automatically change the on and off cycle intervals. This requires that the well operator perform periodic checks for proper pump fillage while the well is being pumped. If the pump is full of liquid when the pumping cycle ceases, additional run time is required and the timer ON setting should be increased accordingly (unless the operator desires full pump fillage at all times).

Types of Timers

Two different types of timers are normally used. A variable percentage timer controls the amount of time expressed as a percentage that the pumping unit operates during a timing cycle. The percentage timer sets the on-time which is a percentage of the total cycle time that includes both the on-time and the off-time. For most oil field use in the USA, a 15-minute percentage cycle timer should be used. A discussion of the reasons follows later. An interval timer is also used in the oil field. Most interval timers have a 24-hour rotating disk with 15 minute on and off tabs. This allows the operator to control whether the unit is on or off at 15 minute intervals throughout the day.

Electricity Costs

One of the main purposes of timers and pump-off controllers is to reduce electricity costs. The cost of electricity is normally based upon the electricity consumption (expressed in kilowatt-hours) and the maximum demand (expressed in kilowatts). The consumption is expressed as the total usage of electricity (in kWh) over a period of one month. The demand cost, however, is based upon the maximum power (in kW) that is used during the billing interval. The average power during each 15-minute power interval is measured. The greatest value of average power (during the 15 minute period) is used for billing purposes. If a high demand occurs for a brief period of time, the demand cost is applied to the entire monthly billing. A typical consumption charge is 5 cents/kWh while a typical demand charge is $8/kW.

Practically all, reasonably balanced, oil field pumping unit motors consume electricity while the rotating counterweights are approximately horizontal and generate electricity when the counterweights are at the top and bottom of the stroke. Some meters run backwards and give credit for generated electricity while other meters will not. The power meters that do not give credit for generation have a ratchet (or electronics) that prevents credit for generation. If several wells operate from one utility power meter, the generated electricity from one motor will be used by another motor.

Following are examples of electrical billing charges on a single pumping well with continuous and part time operation. Assume a 30 H.P. motor that is approximately 60% loaded (0.6 x 30 H.P. x .746 kW/H.P.=13.4 kW) when the pump is full and 45% loaded (.45 x 30 H.P. x .746 kW/H.P.=10.1kW) when the pump is operating continuously with 40% pump fillage. Further assume that the pumping system could operate on a timer approximately 40% of the time with a full pump and remove all of the liquid from the wellbore. Further assume 5 cents per kWh consumption charge and $8 per kW demand charge. If the pumping unit runs 100% of the time, the billing will be approximately $471 per month. The consumption charge will be $363 (.45 x 30 H.P. x .746 kW/H.P. x 24 H/D x 30D/M x 5 cents/kWh) and the demand charge will be $108 (.60 x 30 H.P. x .746 kW/H.P. x $8/kW). If the well is operated 40% of the time, such as 30 minutes on and 45 minutes off, the consumption charge will decrease to $193 (.6 x 30 H.P. x .746

kW/H.P. x 24 H/D x 30 D/M x 5 cents/kWh x .4). The demand charge will probably remain the same at $108 because the maximum demand will not change if the well is shut down even once during the month. The total charge for electricity will be reduced from $471 to $301. Should the pumping system be operated at 6 minutes on and 9 minutes off, the consumption charge remains $193 since it runs 40% of the time. However, the demand charge will be reduced to 40% of $108 or $43 (since the demand charge is based on the average power in a 15 minute period) for a total monthly charge of $236. Operating with a 15 minute total on and off cycle timer instead of a longer cycle results in a savings of $65 per month. Following is a summary of electricity charges.

MOTOR OPERATION	CONSUMPTION CHARGE	DEMAND CHARGE	TOTAL CHARGE
Continuous	$363	$108	$471
40% w/long cycle	$193	$108	$301
40% w/15 min. timer	$193	$ 43	$236

The second factor for selecting a 15-minute on/off cycle is the need for the pumper or operator to spend a minimum of time at the well to check for proper operation of the timer. The timer, when properly set, should cause the pumping unit to run with a full pump until near the end of the operating on cycle; and then, stop the pumping unit, hopefully, after the pump has operated for a few strokes at partial pump fillage. This sequence can be checked in less than 20 minutes and the timer re-set if needed.

Shorter or Longer Pump Cycle Off Times

Inflow performance relationship papers[1, 11] suggest that the producing bottomhole pressure should not be in excess of 10% of the reservoir pressure for maximum production from the well. Applying this concept to timer or P-O-C operations, if the reservoir pressure is 1000 PSI, the producing bottomhole pressure should not exceed 100 PSI at the end of the off cycle when liquid has accumulated in the casing annulus. The bottomhole pressure is the sum of the casing pressure plus the gas column pressure plus the pressure exerted by the liquid column above the formation. This pressure can be determined using modern acoustic fluid level instruments[12] that automatically digitize the acoustic data and process casing pressure measurements to obtain the producing bottomhole pressure. However, a problem in the management of most wells is the lack of knowledge of the reservoir pressure. An inexpensive, acoustic static bottomhole pressure test is satisfactory for determining the maximum producing bottomhole pressure at the end of the shut-in period as a function of reservoir pressure.

Motor Start-Up Power Effect on Cycle Time

When a motor starts a pumping unit system, electrical energy is used to start the counter-weights and cranks rotating. Typically, at start-up, a Nema D motor operates at three times its full load rating for approximately 0.65 second in order to power the counter-weights and cranks to normal operating speed. See Figures 1A and 1B which show measured power requirements during start-up. Figure 1C shows start-up power requirement followed by 3 cycles of rotation with a 30 H.P. motor. The energy consumed during start-up is only 0.01 kWh that costs 1/20 of a penny. Thus, the consumption charge for starting the 30 H.P. pumping unit once every 15 minutes costs only $1.20/month. The demand is increased each time the motor is started during any 15 minute time period. Each start-up per 15 minute time period for a reasonably loaded motor operating 50% of the time increases the demand charge by about 1%. Stopping and immediately starting the motor once each 15-minute period affects the electricity bill less than 1% compared to continuous operations.

A compromise exists for the length of the total on/off cycle time. An additional electrical demand charge will apply if the total on/off cycle time is less than or greater than 15 minutes which is a disadvantage. Heavier, more frequent cyclic loading of the equipment occurs if the on/off cycle time is less than 15 minutes. But, the average producing bottomhole pressure is maintained at a lower value that is an advantage. Timers or P-O-C's operating on an on/off cycle time in excess of 15 minutes will increase the demand charge if only a few wells are involved or if all wells are ever started at once. Longer cycle times allow more liquid to accumulate in the casing annulus restricting liquid inflow. The 15-minute on/off cycle time is recommended unless other factors are more important than the ones discussed.

Procedure to Install and Set the Percentage Cycle Timer

Pump the well continuously at normal producing conditions until the production rate has stabilized. Obtain dynamometer surface and pump cards. A qualitative polished rod transducer is preferred to a quantitative horseshoe load cell because of rapid and ease of installation. Precision surface dynamometer load measurements are not required for calculation of a pump card and pump fillage. Some pumping units do not need to be shut down to install the polished rod transducer. Installation of a horseshoe transducer (which normally requires shutting-down the unit) is more time consuming and changes the plunger location in the pump and also changes the producing conditions of the formation which requires pumping the well for a sufficient period of time for the well to re-stabilize. The percentage fillage of the pump card should be multiplied by 1 to 1.1 to determine the percentage of time that the 15-minute percentage timer should cause the pumping system to operate. If the operator prefers full pump fillage at all times, use 1.0 times the percentage pump fillage. For example, assume that the pump fillage is 25% on the dynamometer pump card. The timer should be set for 27.5 percentage run time. This represents a run time of 27.5 percent of 15 minutes or 4.125 minutes. Next, shut down the well for 10.785 minutes. Then, start the pumping unit and monitor the performance of the pumping system during the next 4-1/8 minutes. The system should produce with a full pump for the first four minutes and then begin to pound liquid due to partial pump fillage. If full pump fillage is not obtained for approximately four minutes, <u>correct</u> <u>the</u> <u>inefficiency</u> <u>problem</u>. The most common cause of inefficient pump operation is gas interference. Set the pump intake below the formation and use a single tube below the seating nipple, or use an efficient downhole gas separator[13] if the pump is placed at or above the formation.

Another method to determine the proper percentage of run time is to shut down the well for approximately 10 minutes. Then, start the pumping unit with a dynamometer monitoring the pump's performance. Continue to operate the well as long as the pump is full of liquid. As soon as the pump plunger begins to "pound" liquid because of partial pump fillage, note the run time while the pump was full. The percentage (or fraction) of time that the pumping system should operate is the run time divided by the 10 minute shutdown period plus the run time.

Still another technique for determining the approximate percentage timer setting is to use the ratio of the well's production to the calculated pump capacity. QROD[17] is a free, simple wave-equation predictive beam pump program that is useful for estimating pump capacity and pumping unit loadings. Divide the well's production by the predicted pump capacity. This is the fraction of run time that the pump should operate if the pump is operating efficiently. This procedure assumes that the pump is filled with liquid on the up stroke and that the pump is operating efficiently. Verify pump fillage with a dynamometer pump card if possible. Use all practical methods available to optimize the setting of the timer including visual observations.

Periodic checks are recommended to maintain the proper run time setting. Many pumping units that produce low volumes of liquid operate in the 6 to 7 SPM range. This results in approximately 100 strokes per 15-minute period. Thus, a 15-minute percentage timer approximately indicates on the dial the number of strokes that will be obtained during the 15-minute period. If the pumping system obtains full pump cards for 25 strokes and then obtains 10 strokes of partial pump fillage, the operator would probably desire to reduce the run time slightly. If the timer were set at 30% run time, reducing the run time by 5% would stop the pump from operating during the last 5 partially filled pump strokes (approximately) and improve efficiency.

Dynamometers offer the most precise manner for properly setting the percentage cycle timers. An operator may visually observe the behavior of the polished rod to estimate the pump fillage. However, complete pump fillage is often difficult to determine by observation, and it is important that the pump fillage is near 100% throughout most of the pump on cycle for efficient operation.

The consumption of power should be measured at full pump fillage and the overall system efficiency determined [12, 14, 16]. The overall system efficiency should be between 40 and 60%. Confirm that the well pumps with a full pump until pump cards are obtained with partial pump fillage that approximates the pump fillage observed when the well is operated 100% of the time. Confirm that the liquid level is at the pump at the end of the pumping on cycle. This insures that the maximum production is being obtained from the well.

Operating Cost Saving Procedures

In the beam system, moderate pumping speed with moderate loading on the equipment will result in better power efficiency than lightly loaded equipment. The pumping unit should utilize a long stroke length. If the moderately loaded pumping system pump capacity exceeds the well's production, use a timer or P-O-C. Gas interference in the pump is the most common contributor to low efficiency. Set the pump below the formation if possible and use a good natural separator[13]. If the pump is set at or above the formation, use an efficient downhole gas/liquid separator having a large, thin wall outer barrel, large inflow ports and proper dip tube design. Using a back-pressure valve on the tubing discharge wastes electricity and increases maintenance requirements. Free gas should be separated from the liquid downhole before the liquid enters the pump so that excessive free gas is not present at the surface in the tubing to cause stuffing box lubrication problems. Having 300 PSI back-pressure on a 4000 foot well will increase the electricity bill approximately 15% and will cause additional rod loading, gear box loading and less plunger travel.

Case Study of Timer Application

A P-O-C was installed on Cobra Oil and Gas Corporation's RVOGTA8 Well. The system did not perform properly because the pump fillage was very erratic due to gas interference. Echometer Company personnel were asked to complete a well performance analysis. Refer to Table 1 that shows data on the well (after the improved gas separator was installed).

An acoustic liquid level depth measurement indicated the liquid level to be 148 ft. over the pump when the well was producing at stabilized conditions. The casing pressure increased approximately 0.1 PSI per minute when the casing valves were closed that indicated that free gas was being produced from the formation and was flowing up through the annular liquid. Refer to Figure 2. A dynamometer test was run without shutting down the pumping unit in order to determine stabilized pumping conditions. See Figure 3. The dynamometer analysis showed that the pump fillage was 27%. Traveling valve and standing valve tests indicated that the pump was in good condition. When a high liquid level is present above the pump and the pump does not fill with liquid on the upstroke, poor downhole gas separation exists. The pump was set at 5,173 feet that is above the formation. The formation is open-hole (4-3/4") and was drilled below the 5-1/2" casing from 5,235 to 5,247 feet. The acoustic data and dynamometer data indicated that the poor "Poor Boy" gas separator was inefficient as is often observed. The well was shutdown for 10 minutes and then restarted. Low pump fillage occurred even after the well had been shutdown for 10 minutes. See Figure 4. The well was tested again after being shutdown for 20 minutes. Again, a dynamometer test indicated low pump fillage and another acoustic test showed the liquid level to be high indicating that the downhole gas separator was still operating inefficiently.

Decisions were made to try to improve the efficiency of the pumping system by installing a better gas separator and then use a timer to control pumping unit operating time. The data would be used in this paper.

The producing bottomhole pressure was approximately 94 PSI, but the reservoir pressure was unknown. Cobra personnel elected to shut-in the well for a maximum of 5 days to obtain reservoir characteristics. The buildup data is shown in Figure 5. The well pressure did not stabilize, but it indicated a reservoir pressure (P*) in excess of 1000 PSI. It also indicated low skin and permeability. Another interesting measurement was the flow of liquid into the wellbore after shut-in that indicated a rate of approximately 10 BLPD that is considerably less than the production from the well. See Figure 6. This build-up data indicates that very little additional production will be obtained after correcting the gas interference problems. The main benefits of better gas separation and use of a timer will be reduced electrical costs, less maintenance due to less run time and better equipment loadings. The lack of liquid flow into the wellbore may indicate that some cross flow occurs in the formation, and probably, the pump should be set as low as possible in the well.

The rods and tubing were pulled. The pump was serviced. The pump had a worn pull tube which was replaced. The wear on the pull tube was probably the result of continuous "pounding" of the plunger when the pump was 20 to 50% filled with liquid. The pump also had two standing valves. Only one standing valve was used when the pump was run back into the well. A tubing anchor was in the well when it was pulled, but the tubing anchor had a broken spring and was not run back into the well. The tubing string consists of 167 joints of 2-3/8" tubing, a seating nipple and a 2-3/8" collar-size gas separator which was 6 feet long. The bottom of the gas separator was placed 3 feet from the bottom of the well in the middle of the producing formation.

The well was pumped overnight. The next day, the liquid level was tested and found to be at 166.88 joints from the surface that is at the seating nipple. See Figure 7. A dynamometer card was run. The well was tested without shutting down the pumping unit and the pump card indicated approximately 30% fillage. With the liquid level at the pump and partial pump fillage occurring, the gas separator was operating efficiently. The well was shutdown for 9 minutes. Then, the well was started and run for approximately 10 minutes. The first 36 strokes indicated full pump fillage; the next 7 strokes indicated the well was being pumped down, and from stroke 43 to the final stroke 60, the pump fillage was relatively stable around 35%. Please refer to Figure 8. The installation of the collar-size gas separator was successful. A percentage 15-minute cycle timer was installed and set to run 33% of the time.

Before the timer and gas separator installation, the well produced 8.2 BOPD and 35 BWPD with 4 mcf/d of gas per day. The well was produced continuously and the electricity bill was calculated at $203 per month. After installation of the gas separator and timer, the oil, water and gas production rates increased slightly as was expected. The electricity bill decreased from $203 to $108 per month. The beam pump system now operates 5 minutes on and 10 minutes off with a full pump most of the on time. Smoother operation of the system is observed. Hopefully, the next downhole maintenance requirement will be at least three times further in the future than if this job had not been performed. A payout will occur in 8 months based upon the reduction in electricity cost and an estimated reduction in maintenance cost due to better equipment loading and 33% run time. The overall electrical efficiency was improved from 35% to 59%.

Conclusions

A beam pump system which has a pump capacity that exceeds the well's production can be operated with a timer or P-O-C to improve overall efficiency. The electrical and maintenance costs will be reduced with a properly operating timer or P-O-C. The recommended 15 minute percentage timer technique for reducing electrical and maintenance costs is a relatively simple technique and inexpensive procedure for reducing operating costs in wells which have a pump capacity exceeding the wells producing capacity.

Acknowledgment

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TOTAL WELL MANAGEMENT by ECHOMETER Company
Group: vogtsberger - Well: RVOGTA8 - Created on: 01/06/1999 12:39:49

General

Well	RVOGTA8	
Company	COBRA	
Operator	ARTIE	
Lease Name	VOGTSBERGER	
Elevation	1000	ft
Artificial Lift Type	Rod Pump	

Comment
4-3CRO COUNTERWEIGHTS = 1331 LBS EACH
165 JOINTS OF TUBING = 5173 FEET AVERAGE = 31.35 FEET/JOINT
HAS A TUBING ANCHOR, 4 FOOT PERFORATED SUB AND A JOINT OF TUBING BELOW SEATING NIPPLE
5 1/2 CASING SET AT 5235 FEET OPEN HOLE 5235 TO 5247 FEET TD = 5247
DONNIE ROYCE W-438-2949 M-720-5915
C-631-5914
ARTIE H-723-9626
1/5/99 -- INSTALLED 6 FT LONG 2 3/8 INCH COLLAR SIZE GAS SEPARATOR AT 5244 FT. THE TD IS 5247 FEET.
REMOVED THE TUBING ANCHOR DUE TO MECHANICAL SPRING PROBLEM WITH THE TUBING ANCHOR.

Surface Unit

Manufacturer	Lufkin Conventional	
Unit Class	Conventional	
Unit API Number	C-320D-256-100	
Measured Stroke Length	100	in
Rotation	CW	
Counter Balance Effect (Weights Level)	-*-	Klb
Weight Of Counter Weights	5000	lb

Prime Mover

Motor Type	Electric	
Rated HP	30	HP
Run Time	24	hr/day
MFG/Comment	GE	

Electric Motor Parameters

Rated Full Load AMPS	41.5	
Rated Full Load RPM	1100	
Voltage	480	
Hertz	60	
Phase	3	
Power Consumption	5.75	
Power Demand	5.45	$/KW

Tubulars

Tubing OD	2.375	in
Casing OD	5.5	in
Average Joint Length	31.36	ft
Anchor Depth	-*-	ft
Kelly Bushing	0	ft

Pump

Plunger Diameter	1.5	in
Pump Intake Depth (MD)	5237	ft

Polished Rod

Polished Rod Diameter	1.25	in

Rod String

	Top Taper	Taper 2	Taper 3	Taper 4	Taper 5	
Rod Type	D	D	D	-*-	-*-	
Length	675	4300	250	-*-	-*-	ft
Diameter	0.875	0.75	0.875	-*-	-*-	in

Total Rod Length	5225
Damp Up	0.05
Damp Down	0.05

Conditions

Pressure

Well State	Producing	
Static BHP	1000	psi (g)
Static BHP Method	Estimate	
Static BHP Date	12/03/1998	
Producing BHP	35.8	psi (g)
Producing BHP Method	Acoustic	
Producing BHP Date	01/22/1999	
Formation Depth	5247	ft

Surface Producing Pressures

Tubing Pressure	44.0	psi (g)
Casing Pressure	16.2	psi (g)

Casing Pressure Buildup

Change in Pressure	0.5	psi
Over Change in Time	3.00	min

Production

Oil	8.4	STB/D
Water	40	STB/D
Gas	4	Mscf/D
Production Date	12/03/1998	

Temperatures

Surface Temperature	70	deg F
Bottomhole Temperature	150	deg F

Fluid Properties

Oil	40	deg.API
Water	1.05	Sp.Gr.H2O

Table1 - Well Data

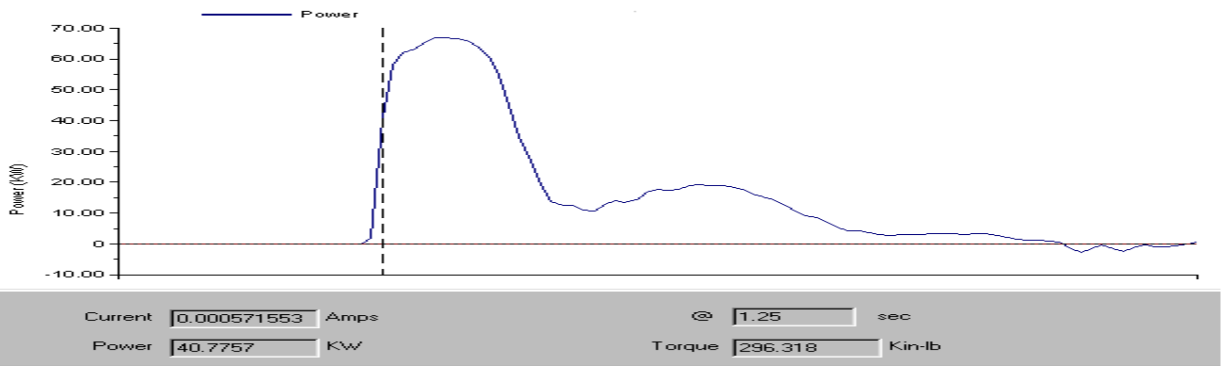


Figure 1A

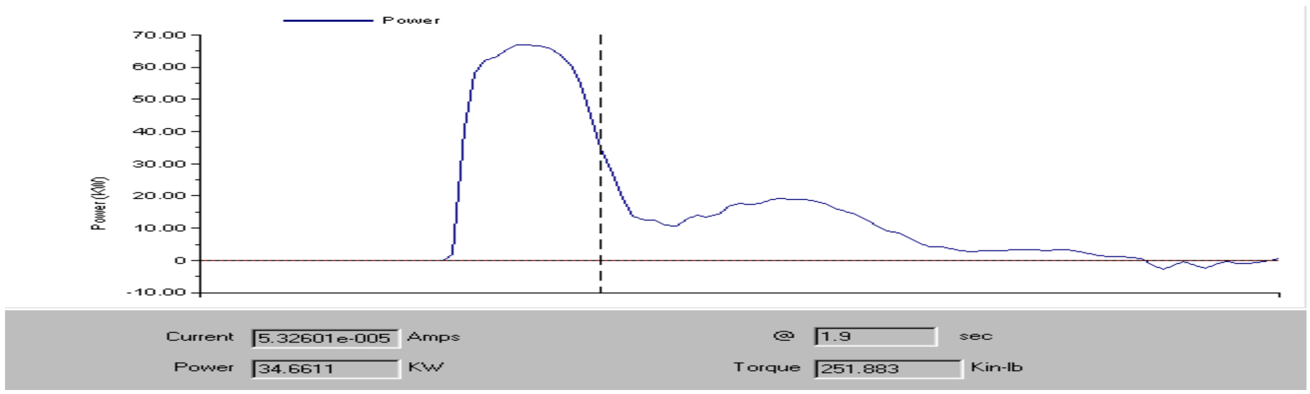


Figure 1B

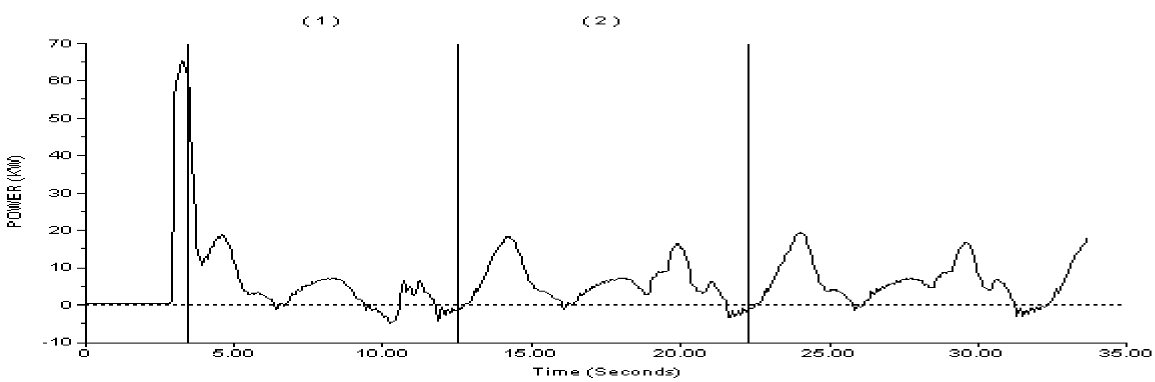


Figure 1C

Figure 1 – Startup Power

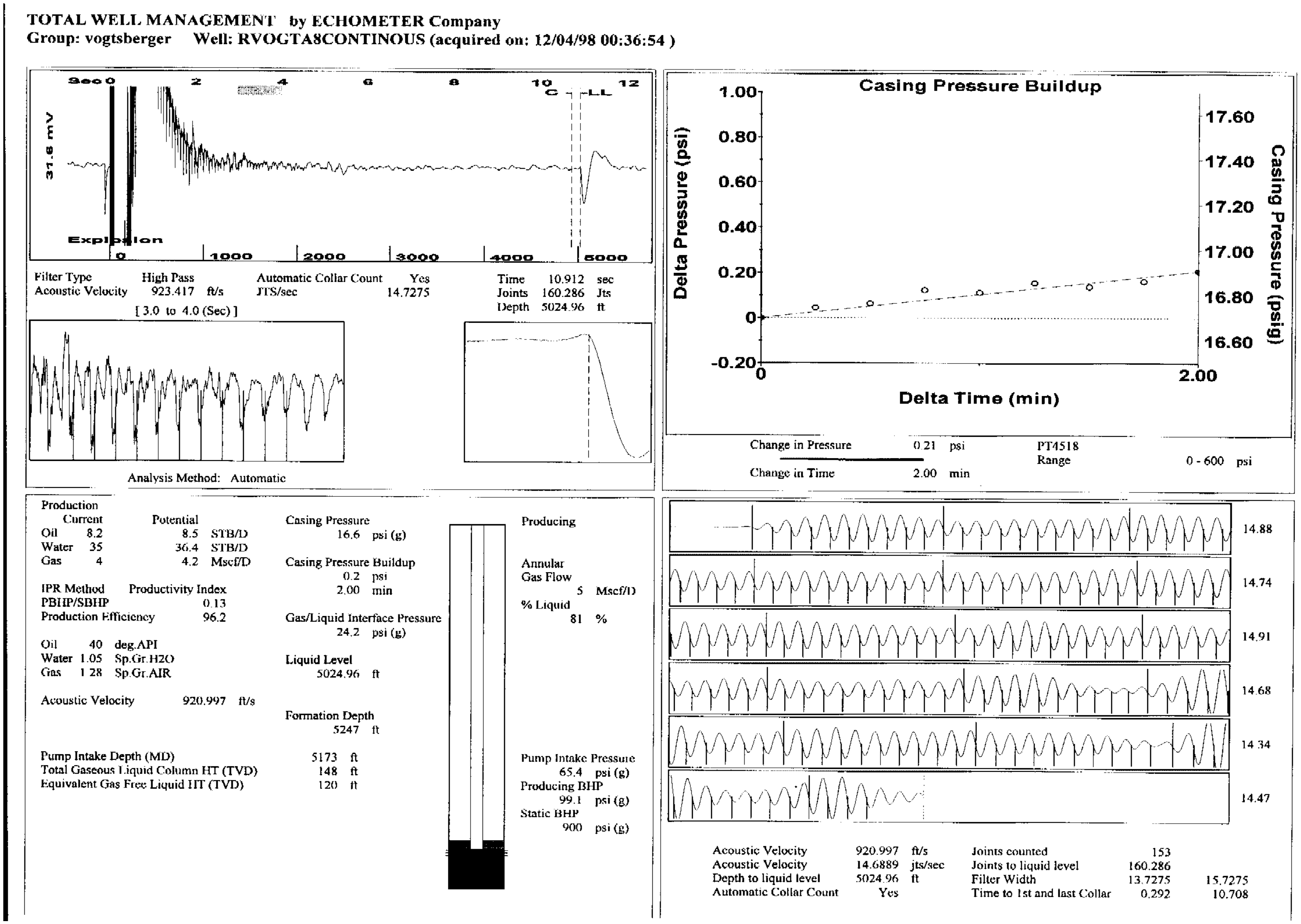
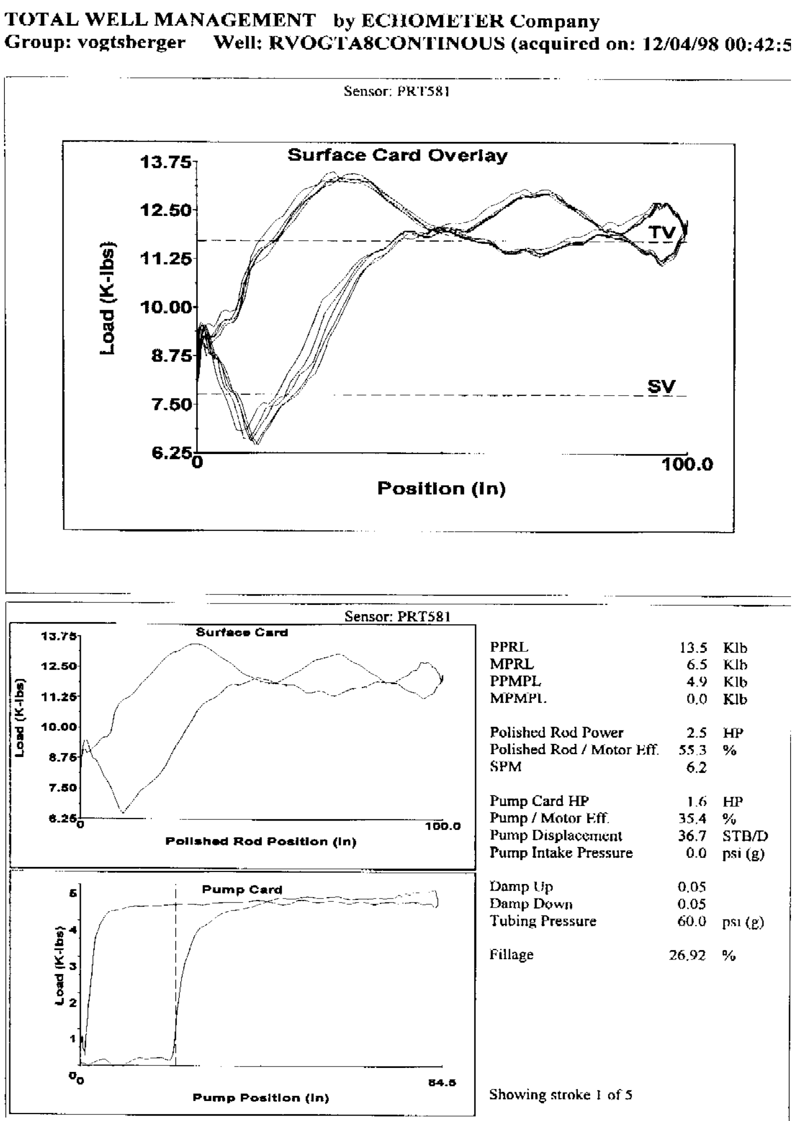
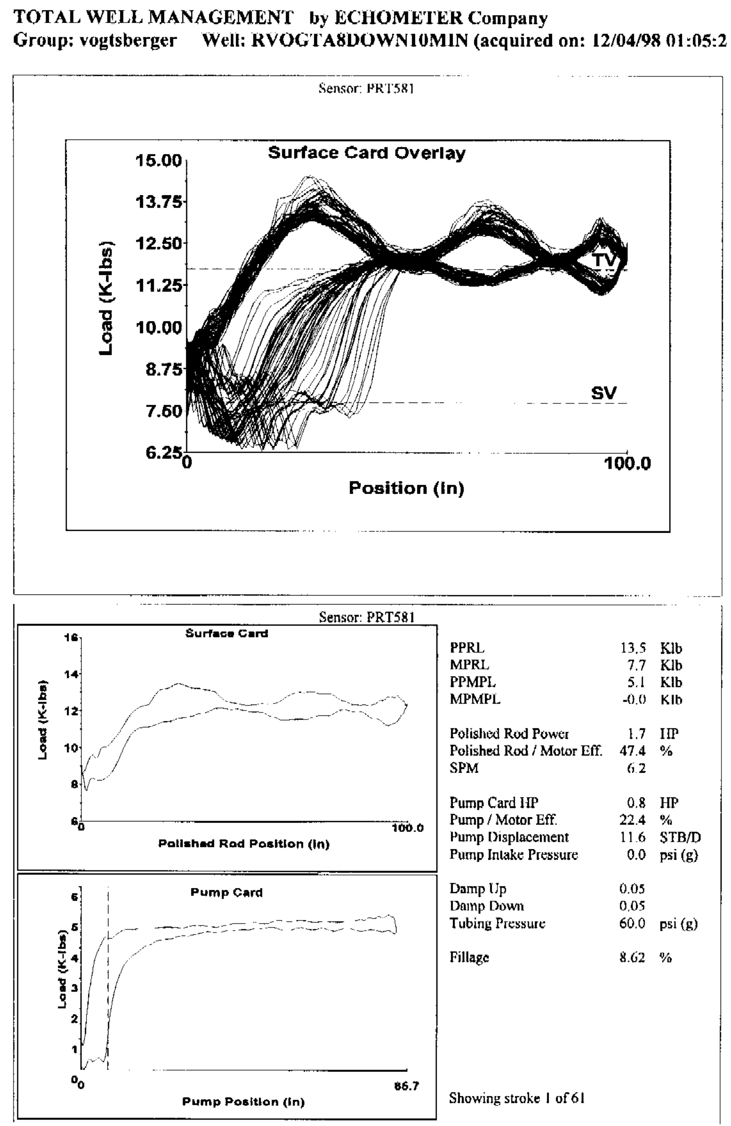


Figure 2 – Initial Acoustic Liquid Level



Initial Dynamometer Test

Figure 3



After 10 Min. Down Time

Figure 4

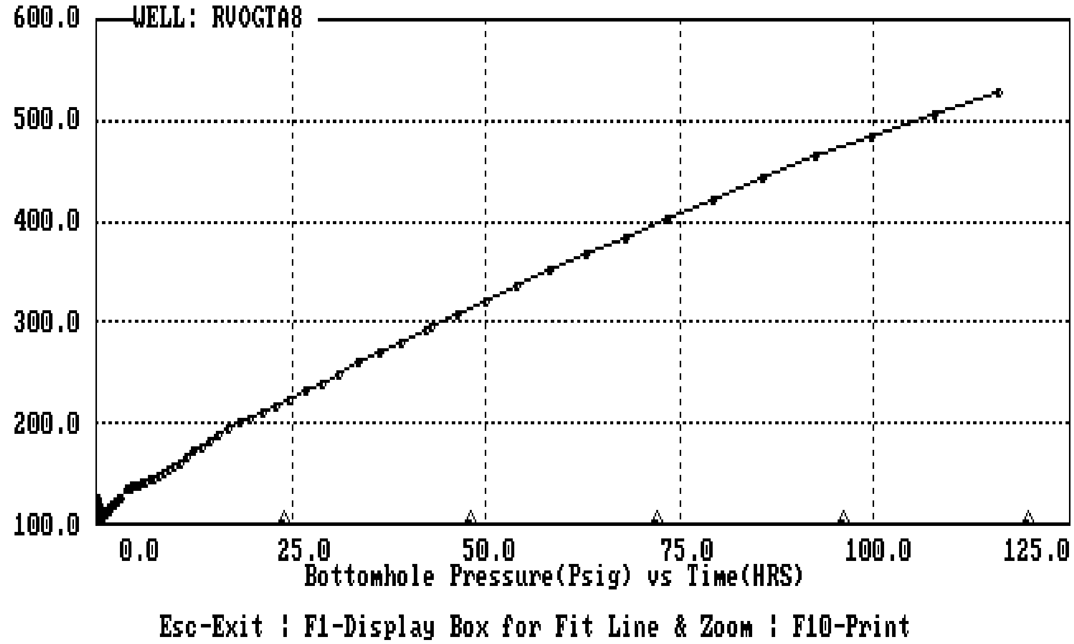


Figure 5 – BHP vs. Time

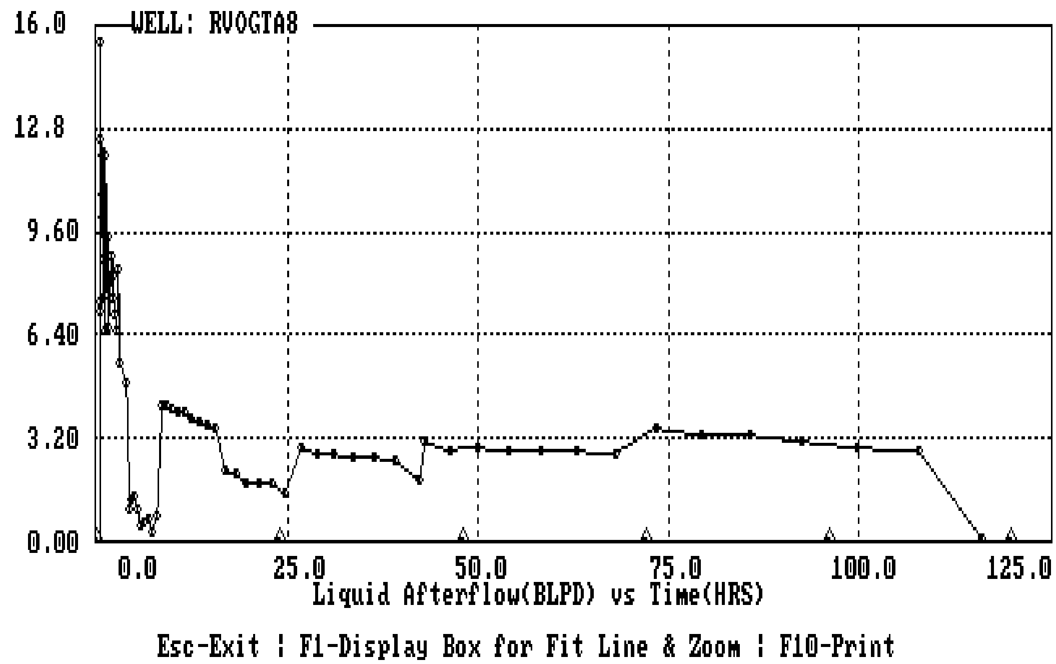


Figure 6 –Liquid Afterflow vs. Time

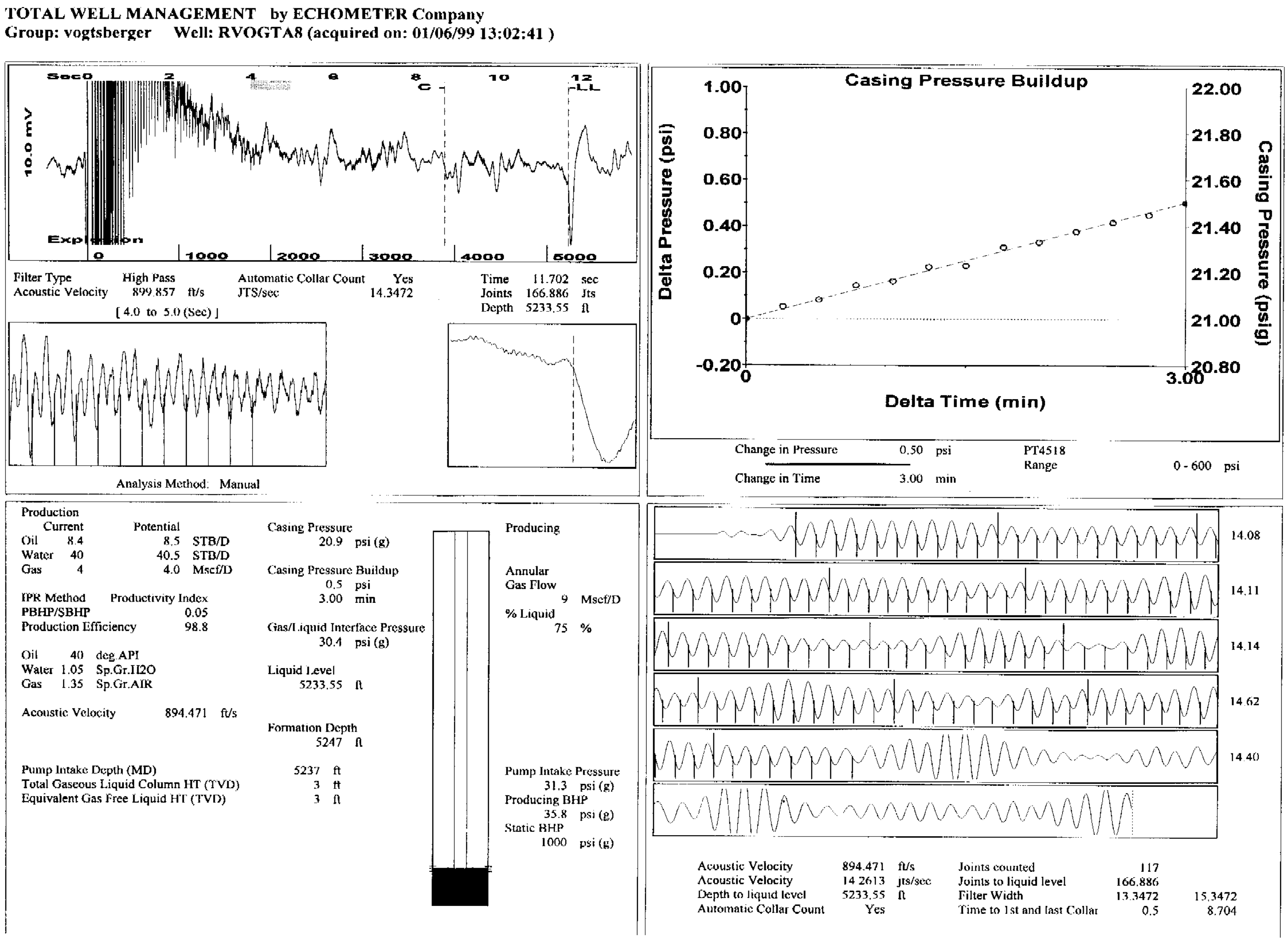
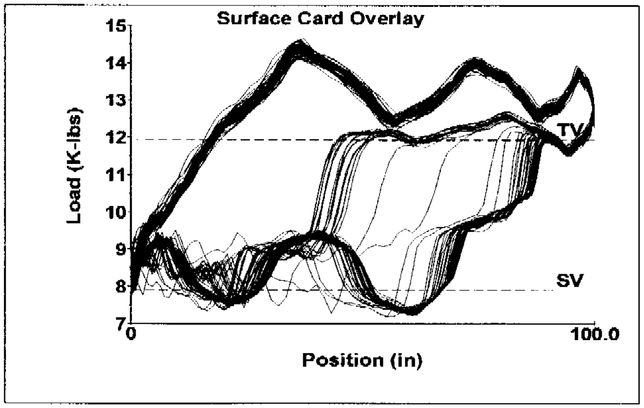


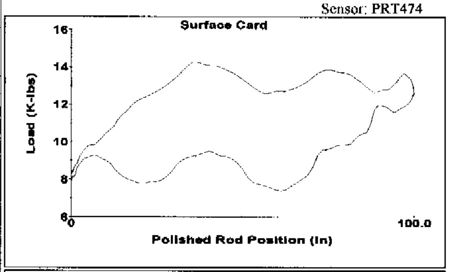
Figure 7 – Acoustic Test After Installation of Gas Separator

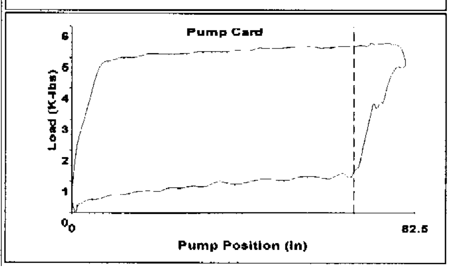
TOTAL WELL MANAGEMENT by ECHOMETER Company
Group: vogtsberger Well: RVOGTA8 (acquired on: 01/06/99 16:34:29)

Sensor: PRT474



Sensor: PRT474





PPRL	14.3	Klb
MPRL	7.4	Klb
PPMPL	5.5	Klb
MPMPL	-0.0	Klb
Polished Rod Power	5.6	HP
Polished Rod / Motor Eff.	61.8	%
SPM	6.2	
Pump Card HP	4.7	HP
Pump / Motor Eff.	52.2	%
Pump Displacement	109.5	STB/D
Pump Intake Pressure	16.2	psi (g)
Damp Up	0.05	
Damp Down	0.05	
Tubing Pressure	44.0	psi (g)
Fillage	84.56	%

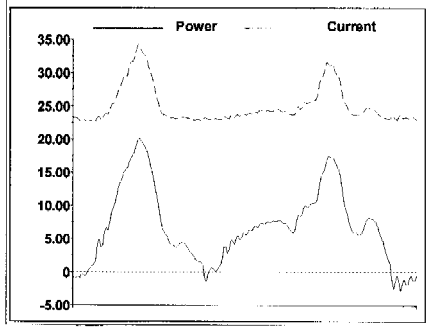
Showing stroke 2 of 60

TOTAL WELL MANAGEMENT by ECHOMETER Company
Group: vogtsberger Well: RVOGTA8 (acquired on: 01/06/99 16:34:29)

Monthly Operation Costs (30 Days / Month)		
Run Time	8	hr/day
Cost With Gen. Credit	93.26	$
Cost No Gen. Credit	95.25	$
Demand Cost	38.41	$
Oil Prod. Cost	38.0	¢/bbl
Liquid Prod. Cost	7.3	¢/bbl
Oil	8.4	STB/D
Water	35	STB/D

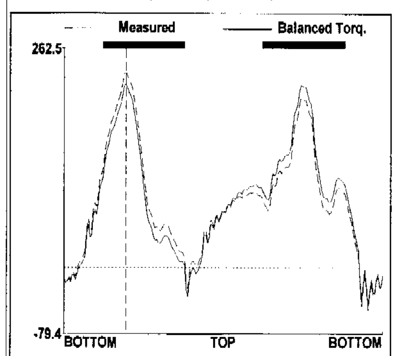
Recommended Minimum NEMA D Motor	12.7	HP
Rated HP	30	HP
Rated Full Load AMPS	41.5	
Thermal Amps	25.2	
Gross Input	9.3	HP
Net Input	9.1	HP
Demand	7.0	KW
Average	20.8	

Average Power		
With Generation Credit	6.8	KW
No Generation Credit	6.9	KW
Avg. Power Factor	30.4	%
System Efficiency	53.7	%



Showing stroke 2 of 60

Torque = 84.5 * P[KW] * EFF / (SPM * SV)



Measured Upstroke Peak	234.1	Kin-lb
Measured Downstroke Peak	203.3	Kin-lb
Marker	234.1	Kin-lb
Balanced Upstroke Peak	219.6	Kin-lb
Balanced Downstroke Peak	218.6	Kin-lb
Counter Balance Change for Adjusted Torque	15.9	Kin-lb
Weight Of Counter Weights	5000	lb
For Adjusted Torque Move Counterweights	3.2	in
Strokes Per Minute	6.1	
Motor/Belts Efficiency (EFF)	0.8	fraction
Speed Variation	0.95	fraction

Showing stroke 2 of 60

Figure 8 - Dynamometer After Gas Separator Installation