EXTENDED BEAM UNITS: BEAM PUMP GEOMETRY MODIFICATIONS FOR IMPROVED PRODUCTION

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Abstract

In 1989 water injection rates were increased in the North Cowden field. Lift revisions greater than 700 barrels per day required an ESP installation because of the capacity limitations of the existing beam equipment. The extended beam unit was designed to increase production rates to 900 barrels per day. The first unit was installed in July of 1993. Currently there are six units in service. This paper will discuss the evolution of the design and the learning process over the last three years.

Specifications

The extended beam unit is built from the structure of an American 912-365-168 pumping unit. The stroke of the unit has been increased to 192 inches. This is done by replacing the walking beam with a new piece of steel I beam 2 feet, 2 1/4 inches longer. The driven bar length changes from 184.75 inches to 211 inches. The radius of the horse head is built up to fit the new geometry of the stroke. New wrist pins are installed, the gearbox and bearings are serviced and inspected for wear prior to running. This "poorboy" method of increasing production has previously been tried in California heavy crude fields where long slow stroking is preferred. Like many other methods of lift in the field, older ideas can be recycled, expanded and refined to yield a different result in a different place.

Operating Conditions

The North Cowden Unit production horizon is in the Grayburg/San Andres at a depth from surface of 4000 to 4600 feet. Pump seating depth is typically 4300 feet for beam wells, and 3800 feet for ESP wells. Casing diameter is 5.5 inches set to the top of the producing interval, with 4.75 inch diameter open hole beneath. All equipment must be designed to survive the severe corrosive conditions of the sour environment. Calcium carbonate, calcium sulfate, and iron sulfide scales are present in the waters. The water to oil ratio is 12 to 1 field wide. Direct operating expense (power, field operation salaries, contract labor, subsurface equipment , and well servicing) were $2.10 per BOE in 1995. Indirect costs (workovers, management, engineering, accounting, legal support, and information technology) add $2.00 more for a total of $4.10 COE/BOE.

History

Located 17 miles northwest of Odessa in Ector and Andrews counties, the North Cowden Field was discovered in the mid 1930's. The original oil in place totaled 3 billion barrels. Today, production totals 500,000 barrels each month. The field has 1490 wells in an area of 33 square miles. In the late 1960's the field was unitized, and water flooding commenced. Prior to waterflood, during primary production, most wells were sized to pump 150 to 200 barrels of production. This could be achieved with a 320-305-100 conventional pumping unit and a 1.5 inch bore insert pump.

The first response to water increases was met with the 640-305-168 Lufkin air balance unit. With a 2.25 inch bore tubing pump, these units were capable of producing 500 to 700 barrels of production at 4300 feet with reliability. This design could take care of the required production rates for all but a few wells in the field. In time, the dictum of not exceeding injection rates and pressures beyond the fracture point of the reservoir was rationalized as antiquated thinking. Starting in 1989 several water injection pilots were initiated to explore the validity of new reservoir models. Soon total fluid rates in some wells exceeded the ability of the 640-305-168 Lufkin air balance to handle. The cost to upgrade the production capacity of a field this size is formidable. Two methods to produce these wells were pursued: fiberglass rods and electrical submersible pumps.

Fiberglass rods at North Cowden have not been widely used. This can mostly be attributed to the unfamiliarity of the field operators with the peculiarities of their dynamometer cards, and the presence of frac sand, especially in new drilled wells. The first design that was tried had 70% 1.2 inch glass, and 30% 1.50 inch sinker bars. A 640-365-168 conventional pumping unit was run in the 120 inch stroke at 11.6 strokes per minute. With a 2.25 inch bore tubing pump at a 4300 foot pumping, depth this design yielded 900 barrels. Pin breaks in the sinker bar lift subs prompted the laying down of sinker bars. One inch sucker rods were put in their place in a 50% glass, 50% steel design. This design endured until the fiberglass rods reached their useful cycle limits, at which point they were not replaced. New fiberglass rod designs and materials have been introduced since those tried at North Cowden in 1989, but the collective consensus of field operations personnel is not to use fiberglass rods in the future. Only about twelve wells were installed with fiberglass rods, some not lasting a month before they were converted to ESP installations.

ESP installations became the equipment of choice in 1989 for wells producing more than 700 barrels per day. It is reasonable to expect ESP equipment to stay in service for three to five years provided it is sized correctly to production inflow. Critical to ESP design, however, is the production inflow performance calculation, the drawdown the ESP can achieve with an increased production rate. As fluid levels go up, oil production declines. The need to keep flush production is acted upon quickly. Infill drilling and water injection increases made lift revisions of ESP equipment a full time job for one person. In 1992 the average cost per pull for ESP's was $22,459. Resizing and variable frequency drive testing historically account for 75% of ESP pulls at North Cowden. Since early 1994, an alliance agreement with an ESP manufacturer has made a significant cost reduction in operating ESP equipment. The cost per pull has fallen to $10,234 through June of 1995. Better calculation of drawdown, and a single source for new equipment have been the process improvements that have made a difference in total system cost. A new leasing program allows the cost of purchasing ESP equipment to be spread out over several years, benefiting both operator and supplier.

Reasoning

In 1992, it became reasonable, because of the economics of operating ESP equipment, to explore methods of increasing the productive capacity of conventional beam pumping. Joe Minnesale, an Amoco mechanical engineer, sent out an inter company memorandum comparing the total system cost of beam and ESP. K. B. Nolan and S. G. Gibbs with Nabla Corporation gave a school in 1993 at the Southwestern Petroleum Short Course comparing ESP, beam, and hydraulic lift. The conclusions of these studies, based on fiberglass rods at a production rate of 900 barrels, both gave rod pumping an advantage in total system cost over the other methods of artificial lift, provided surplus or underutilized equipment is used. Surplus pumping units are presently available at 75% of fair market value from other Amoco operating locations. Underutilized pumping units within the field are the first choice to use for a lift revision. Used outsourced steel sucker rods are available for 50% of new price. As oil production declines in a mature waterflood, every cost savings measure must be pursued.

Design Parameters

The first design for the extended beam unit uses an API 87 rod design of 1600 feet of 1 inch grade KD rods, 1950 feet of .875 inch grade KD rods, and 750 feet of 1 inch grade KD rods on the bottom. The pump is a 2.25 inch bore mercury type tubing pump with a 20 foot long plunger, and a 3 foot long barrel. This pump is designed to serve in abrasive, corrosive, high water cut service. Unit speed is 8.5 strokes per minute. A service factor of .9 is used in the rod design to allow for corrosion conditions. The tubing anchor is set as close to the casing shoe as possible to minimize the amount of tail pipe in open hole. Usually there is 300 feet of unanchored tubing that is run in the open hole. Unit speed is limited to 8.5 strokes per minute.

The second design uses an API 88 rod design of 3000 feet of 1 inch plastic coated high strength rods, and 1300 feet of 1 inch grade KD rods. The pump is a 2.75 inch bore conventional tubing pump with an on-off tool and a tubing drain installed. The diameter of the plunger is greater than the inside diameter of the tubing, which necessitates the pulling of the tubing whenever the pump fails. Unit speed is limited to 7.0 strokes per minute. 900 barrels per day is achieved at 6 strokes per minute. The fluid level is monitored to avoid pumping off.

Installation Cost

Installation cost is as follows: Pulling unit rig time - $ 2000. Used rod string - $6500. Pump - $5000. Conversion cost for the extended beam including installation of the pumping unit - $7000. New wrist pins - $1500. Tubing, SPOC, and motor are surplus. Total installation cost is under $22,000.

Productivity Index

Any consideration of the total system cost of a design takes into account the productivity of the well. If the well was previously an ESP, there is a 500 foot difference in the depth of the inlet of the pump. Reservoir pressure in the North Cowden field is about 1200 psi, and the productivity index is 1.0 in the most prolific parts of the field. Lowering of the pump inlet depth and lowering of the pump inlet pressure yields an increase in total production of 1 barrel per psi drop. A 5 barrel increase in oil production a day generates $ 21,900 in gross revenue a year with a base estimated $12 oil price. A net oil price, considering direct and indirect cost is in the $7.50 range. The more cautious method for calculating payout is to use the net numbers. Net revenue is $13,600 a year.

Power Consumption

Power saving alone cannot justify changing out an ESP. If it has reached the end of a long run, the cost of replacement with another ESP may actually be less than installing an extended beam unit. It is worthwhile to tear down the ESP to find the cause of failure, and estimate the cost to return to service. The balance of the decision may swing in favor of the extended beam unit if the repair cost exceeds the installation cost of the extended beam unit. Measured power consumption for the extended beam is 2.87 cents per barrel, for an ESP3.37 cents per barrel. At a 900 barrel rate, the power bill per year is $9427 for the extended beam and $11,070 for the ESP. Calculating power savings alone, it would take 12 years to payout the installation of the extended beam unit. Operating costs become more equal when ESP equipment fails. The strategy remains to retire ESP equipment as it fails before installing an extended beam unit.

Beam Lift Analysis; Predicted and Diagnostic Results

The field operations staff of Amoco are fortunate to have the support of the Artificial Lift Team from the Tulsa Research Center; Jim Lea and Henry Nickens. They provide technical support for the computer programs that aid in the design of beam, esp, and gas lift wells. The training and consultation provided has been valuable in optimizing artificial lift equipment.

The beam lift analysis program is the tool that is used to design the predicted performance of the extended beam unit. Once the unit is installed, and the pumping rates and fluid levels have stabilized, a dynamometer card can be downloaded from the SPOC central. This card is then transferred to a summagraphics tablet and digitized. From this digitized card, the blap diagnostic program can interpret the downhole pump card, and the real time rod and gearbox loads. This is a great help in identifying design improvements, or problems.

The first design for the extended beam achieved a bottom hole pump stroke of 192 inches, equal to the surface stroke of the unit. At a pumping speed of 8.5 strokes per minute, the peak polished rod load is 24,500 pounds. Production rates of were slightly better than predicted. Diagnostic gearbox loads fell into an acceptable range once the unit was balanced correctly. Predictive rod loading was slightly higher than the diagnostic results. Overall, according to blap, this design meets the limitations on rodstring, gearbox, and structural loads.

The second design for the extended beam achieved a bottom hole pump stroke of 182 inches, ten inches less than the surface stroke of the unit. At a pumping speed of 7 strokes per minute, the peak polished rod load is

27,500 pounds. Production rates were equal to those predicted. Predictive rod loading is higher than the diagnostic results. Diagnostic gearbox loads exceeded manufacturer's specifications at 120% of recommended load. This was remedied by slowing the unit down, and allowing the well to carry a higher fluid level. Some production was sacrificed in order to protect the gearbox. Structural loading was in an acceptable range.

Analysis of Failures

Historical beam lift failure data from North Cowden has statistically split into three areas. 1. rod and tubing failures due to corrosion/compressive loading in the bottom 20% of the production string (50%). 2. Mechanical failure of polished rods, sucker rod pins and sucker rod boxes due to mishandling, fatigue or inadequate make up (17%). 3. Production decline due to pump failures (33%). Failure frequency for wells producing less than 300 barrels per day averages one failure every three years. For wells in the 300 to 500 barrel range the failure frequency rises to one failure every 18 months. For wells in the 500 to 700 barrel range, one failure every 12 months. Logic would follow in the production range of 700 to 900 barrels where the extended beam unit operates, the failure frequency would be higher. With a test group of six wells, the pattern of problems encountered can more quickly be analyzed and acted upon. These wells as a group have 11 chargeable failures in 122 months of accumulative run time, or an average of 11 months between chargeable failures. Six of these have been pump failures, four tubing failures and one pin break.

Rod and tubing failures related to corrosion are the first area to focus on. A water soluble corrosion inhibition chemical is applied at a rate of 35 parts per million, with a treating frequency of three times per week. Flush volume is five barrels of produced water. When the corrosion program is maintained correctly, and rod guides are installed in the diagnosed compressive area of the string, rod and tubing failures can be controlled.

Pump problems identified have been barrel splits near threaded connections, and erosion/corrosion in the lower extension of the barrel. The metallurgy of the 2.75 inch bore pump was upgraded to the standard of the rest of the pump inventory. A pump with brass nickel-carbide coated barrel, 316 stainless steel trim, monel guided cages, and silicon nitride balls was supplied by the pump manufacturer.

Summary

ESP's, fiberglass rods, ribbon rod, the Rotaflex system ,and other steel rod installations have the capacity to lift 900 barrels of production at 4300 feet. With a variety of systems from which to choose, economics, well depth, and the productivity of the individual well should guide the selection of the appropriate system.

The extended beam unit was the outgrowth of the need in the North Cowden Unit to manage the economics of lifting 900 barrels of fluid in a 12 to 1 water to oil ratio environment. Since gas interference is not a problem, high volumetric efficiency is possible. With the advantage of lower pump seating depth, and lower flowing pump intake pressure, the extended beam unit is superior at unloading a well, compared to a ESP installation. The most important component of the economic comparison between the two is the sub surface repair cost of the extended beam and the monthly rental cost of the ESP.

The extended beam unit costs $ 3600 a year to repair, averaging .9 pulls a year at a cost of $4000 per pull. The ESP cost $12000 a year to lease. The extended beam unit costs $15,870 a year to operate including power, repair and chemical cost. The ESP costs $24,850 a year to operate including power, leasing, and chemical cost. Leasing costs fall 25% if the ESP survives the first two years of the lease. Operating overhead and indirect costs are considered equal.

Once the conversion is made, the extended beam unit can expect many years of service. An ESP is usually retired after five years of operation, and the leasing cycle must be renewed. As production declines, controlling operating expense has the greatest impact on cash flow. COE / BOE is the measure for the effectiveness of an artificial lift system. Oil production, not total barrels of fluid lifted determine the economics of producing a well. At some point in a waterflood operation, the lifting costs of water production for an individual well can exceed the value of the oil extracted. An extended beam unit can extend the life of high volume marginal wells. Producing 900 barrels total fluid per day, at a 4300 foot pump depth, the extended beam unit can economically support wells producing 10 barrels of oil per day with a $7.50 per barrel net oil price. The cash flow return (production revenue less operating cost) is $11,400 per year. The extended beam unit is a viable choice for oil producing wells with production of 900 barrels total fluid per day, and a 4300 foot pumping depth.

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The efficiency of artificial lift can be found from the formula

$$eff = \frac{HP_{out}}{HP_{in}}$$

which can be approximated as

$$eff = \frac{.0000054 \times BPD \times LIFT(ft)}{KW}$$

where

BPD = 24 hr production (bbl)

LIFT = depth - average fluid level (for low surface pressure and high water cut)

KW = electrical power to motor from power meter.

POWER USAGE

ESP 1100 BBL/ DAY — 3850 Pump Depth

Net Lift 3350' — $13,560 Year or $.0337 per BBL

$$\frac{.0000054 \times 1100\ BBL \times 3350'\ Net\ Lift = 19.98}{1246\ KWH/Day / 24\ Hours = 51.94} = \underline{38.5\%\ Efficiency}$$

BEAM 1100 BBL/DAY — 4350 Pump Depth

Net Lift 3800' — $11,625 Year or $.0287 per BBL

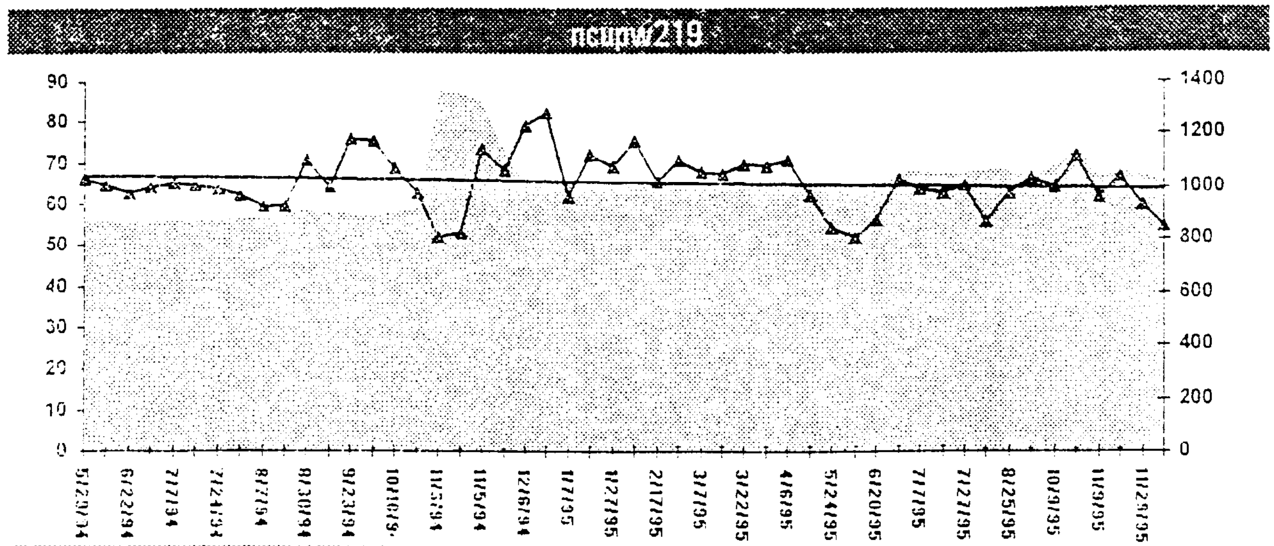
$$\frac{.0000054 \times 1100\ BBL \times 3800'\ Net\ Lift = 22.57}{1068\ KWH/Day / 24\ Hours = 44.5} = \underline{50.7\%\ Efficency}$$

NCU 219

PREDICTED BEAM EFFICIENCY COMPARISION AT 4300 FEET								
	stroke length	pump bore	spm	production rate	rod design	overall efficiency	$ power $ month	pumping unit
v1	120	2.25	11.6	904bbls	70/30 fiberglass/steel	49.34	$943.00	640c 365-168
v2	144	2.25	11.1	911bbls	76 api high strength	62.61	$714.00	640c 365-168
v3	168	2.25	9.7	906bbls	87 api high strength	62.81	$733.00	640 air 365-168
v4	192	2.25	8.4	910bbls	97 api grade kd	58.78	$783.00	912c 365-192
v5	168	2.75	7.1	947bbls	88 api high strength	70.11	$674.00	912c 365-168
v6	168	2.75	7.1	930bbls	88 api high strength	71.53	$674.00	912 air 427-168
v7	192	2.75	5.9	903bbls	88 api high strength	70.65	$645.00	912c 365-192
v8	192	2.75	5.85	907bbls	88 api high strength	75.52	$587.00	912 air 427-192

Pulling History Extended Beam Units

	ncu 219	ncu 631	ncu 711	ncu 720	ncu 750	ncu 1033
Jul-93		start				
Aug-93						
Sep-93						
Oct-93						
Nov-93						
Dec-93						
Jan-94			start			
Feb-94						
Mar-94						
Apr-94						
May-94		pump fail				
Jun-94						
Jul-94						
Aug-94						
Sep-94				start		
Oct-94						
Nov-94	start				start	
Dec-94						start
Jan-95		tbg fail				
Feb-95				pump fail		
Mar-95		pump fail	tbg fail			
Apr-95	pump					pump
Jun-95						
Jul-95						
Aug-95		tbg fail			tbg fail	
Sep-95						
Oct-95						
Nov-95			7/8" pin			
Dec-95					pump fail	1" pin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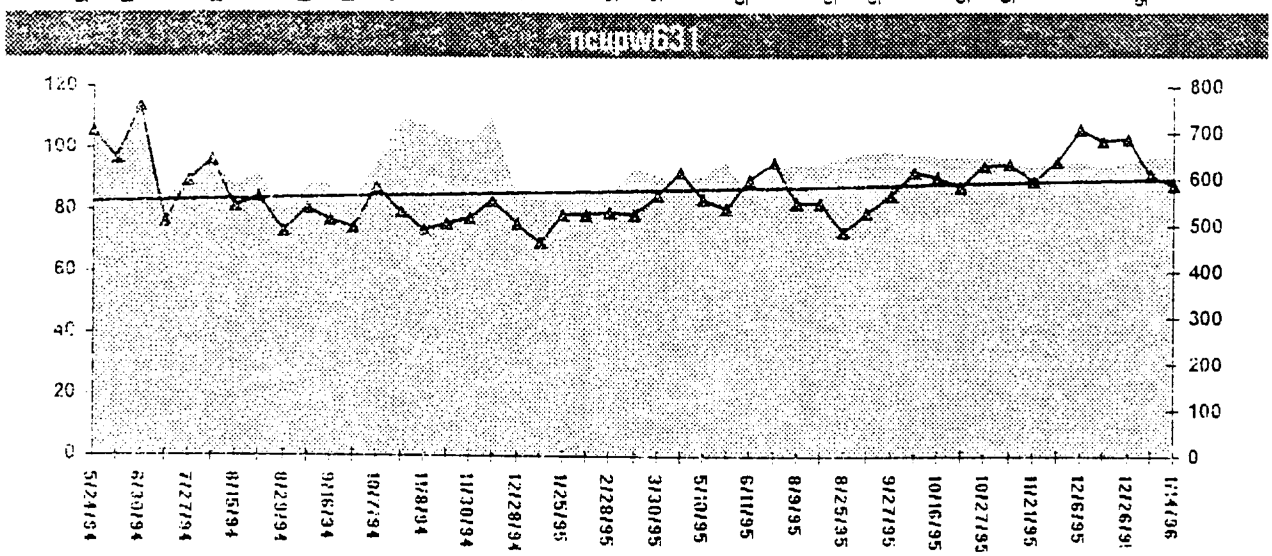
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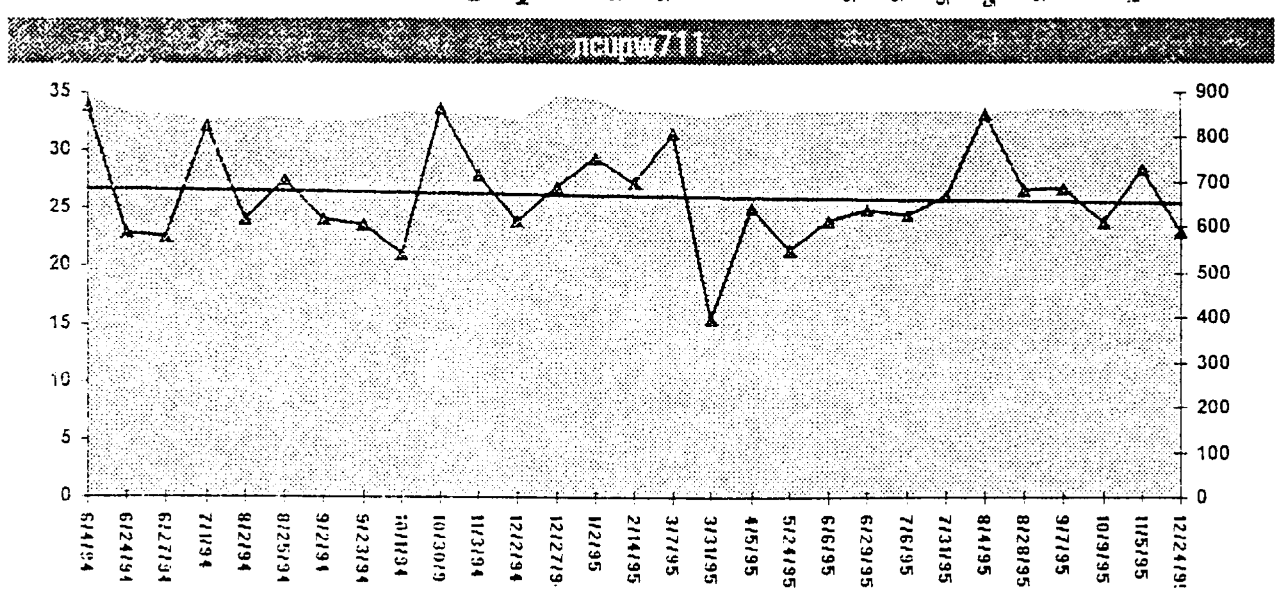
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