MONTANUNIVERSITÄT LEOBEN

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Master Thesis

Alternative Artificial Lift Systems with Special Focus on Hydraulic Pumps

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Affidavit

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

May 21st, 2012 Sophie-Marie Oberbichler

Acknowledgement

At this point I would like to thank all those who supplied my work and made the becoming of this master thesis possible. First of all my thanks go to Dr. Siegfried Müssig whose invalueable supervision and guidance from the first day helped me to develop a deeper understanding not only for the topic itself but also for the importance of some – apparent – minor details. I also want to thank him for the inestimable patience he showed when answering even the most obvious questions.

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Abstract

Within the large variety of different artificial lift systems applying Pascal's Principle i.a. hydraulic drives for sucker rod pumps, which are basically not a new invention in the oil-producing industry can be found. For decades the application of these systems has not been interesting because OPEX where significantly higher than the one of mechanical drives. The first part of this thesis deals with three new developed hydraulic sucker rod drives which imply recent developments, as computer control and real-time monitoring. These systems and the possibility to increase upstroke velocity and therefore to increase the number of strokes per minute as well as new possibilities to improve energy efficiency of the system (esp. potential energy storages during the downstroke) increase the economic performance of these systems significantly.

While artificial lifting of oil has been done quite early in the history of oil production the de-liquification of gas wells to overcome liquid loading is not so common in the industry. But in order to increase ultimate recovery several new artificial lift systems, especially designed for lifting just small amounts of fluids and decrease CAPEX as well as maintenance necessity and OPEX, have been developed. The second part of this thesis compares two recently developed de-liquification systems in terms of CAPEX, OPEX, maintenance intervals, and application depth etc. in order to find economical solutions for the liquid-loading problem in gas wells.

In the third part of this thesis one existing oil well completion (conventional Pump Jack) is compared to a hydraulic drive if it would be installed at the same well under technical and economical aspects. The same is done with an existing gas well that is actually de-watered by a PC-Pump, which is compared to one of the hydraulic deliquification systems.

Introduction

Worldwide roughly one half is produced by an artificial lift system. While artificial lifting of oil has been done quite early in the history of oil production the de-liquification of gas wells to overcome liquid loading is not so common in the industry. [1]

When talking about “Hydraulic Pumps” the thought comes first to the conventional hydraulic artificial lift systems as the Jet Pump and the Reciprocating Piston Pump. But one look in a big oil magazine or a quick internet recherche shows a large variety of different artificial lift systems, all not very well known, but all applying Pascal’s principle[1].

Hydraulic drives for sucker rod pump are not a new invention. Development on hydraulic pumping units started in 1936, but had never played a major role in artificial lift. Therefore the development and research on these systems is not dominated by the large service and pump manufacturing companies as for Pump Jacks, ESPs, Gas Lift or PCPs, but is done either by small, innovative companies or by companies who do not have much experience in the E&P business.

When producing gas wells the main limiting factor is the pipeline pressure which is around 60 – 80 bar for big gas pipelines. After the production pressure decreases below pipeline pressure the use of compressors is necessary which then increases OPEX when a certain level is reached and the well is not producing within the economic range any more.

Especially in reservoirs with strong water drive, wells will die due to liquid loading. Hereby water accumulates within the well and increases the backpressure on the formation significantly. As the reservoir pressure decreases this backpressure will become too high for the liquid to be lifted out of the well. [3]

To overcome those problems RAG produces gas from low pressure reservoirs (tail end gas production) into the lower pressure regional supply pipelines (5 bar) which eliminates the need for big and costly compressors. By using mobile micro-compressors even gas wells with well head pressure below 1 bar can be produced. In combination with modern de-liquification technology therefore Ultimate Recovery Factors of around 95% are possible.

The development of the US shale plays and Coalbed Methane Fields created a not-known necessity of de-liquification systems for gas wells, because both types of unconventional wells produce high amount of liquids. So several new artificial lift systems, especially designed for lifting just small amounts of fluids and reduce CAPEX as well as maintenance necessity and OPEX, have been developed. These properties also are interesting in the search of new low-cost and low-maintenance methods for de-liquification of conventional tail end gas wells.

[1] Pascal's principle : Pressure applied to an enclosed fluid is transmitted undiminished to every part of the fluid, as well as to the walls of the container

Operating Principle of conventional Artificial Lift Systems

Beam Pumps

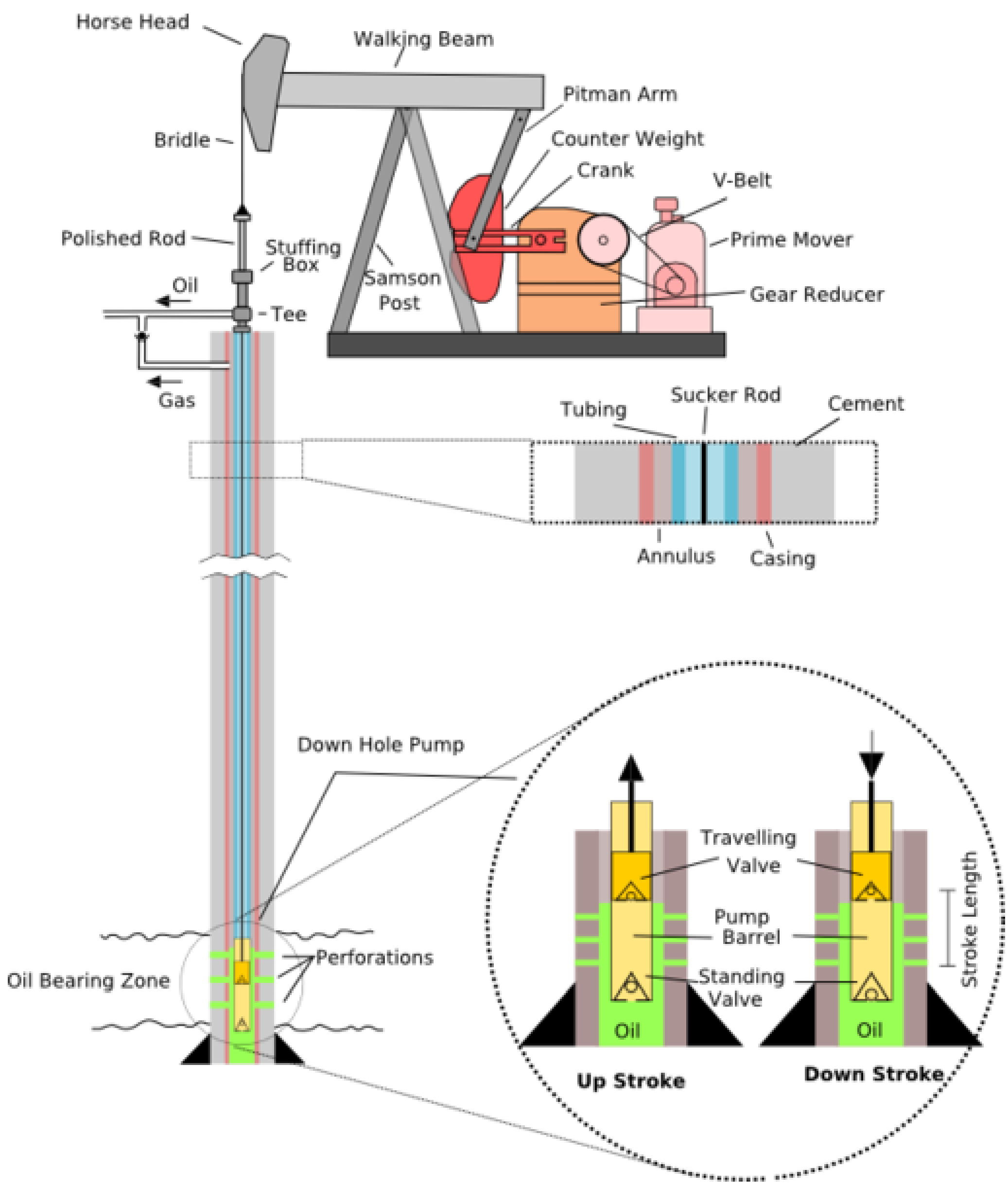


Figure 1: Conventional Beam Pump – Sucker Rod System[1]

Conventional Mechanical Pump Drive

Figure 1 shows a classical Sucker Rod Pump with a conventional mechanical pump drive. As shown in the figure, the prime mover, normally an electrical motor, is connected to a gear reducer by a V-Belt. The gear reducer drives a crank-shaft and therefore a combination consisting of a crank, pitman arm and walking beam, which converts the rotational movement of the crank shaft into an alternating lifting/lowering movement of the walking beam and horsehead. The rod string is connected to the horse-head by a bridle [5].

Adjustable counterweights are mounted on the crank in order to balance the unit and provide a smooth sine-shaped movement. Additionally these counterweights act as potential energy storages. During the downstroke the counterweights are lifted and reach their peak point at the lowest point of the downstroke therefore store a part of the freed potential energy. During the upstroke the counterweights move down, thereby assisting the upstroke movement.

The Rod String

As shown in Figure 1the rod string consists of three basic parts: The polished rod at the top of the string, the rod string itself and the downhole pump.

The polished rod

The polished rod connects the pumpjack to the downhole portion of the rod string. It is the only rod which is exposed to the air. It is usually two to three times longer than the pumpjack stroke and has to be the strongest rod in the rod string. Due to the fact that the maximum loads of the string occur in tension it is the rod which has to carry the highest loads in the string. It is – as its name already tells – highly polished to provide a hydraulic seal between the well head and the environment and to glide easily through the stuffing box packing. It can be made of several materials, including bronze, high-strength carbon steel, or, most common, stainless steel due to the highly corriding combination of downhole fluids and air[7].

Sucker Rods

Sucker rods normally consist of 7.62 m (25 ft joints with a threaded pin connection (male) on both ends. Manufacturers furnish a threaded coupling (female) on one end of each rod. The size increases in 1/8 in increments.

API Rod No.	**Rod Size** **in**	**Metal Area** **sg. in.**	**Rod Weight in air, lb/ft, Wr**	**Rod Weight in air, kg/m**
4	1/2	0.196	0.72	1.07
5	5/8	0.307	1.13	1.68
6	¾	0.442	1.63	2.42
7	7/8	0.601	2.22	3.30
8	1	0.785	2.90	4.31
9	1 1/8	0.994	3.67	5.46
10	1 ¼	1.227	4.53	6.74

Table 1: API Rod Sizes[5]

Additionally to the normal sucker rods also sinker bars can be installed. Basically they are larger in diameter and heavier than conventional sucker rods and therefore assist the rod string in falling down during the downstroke and shall reduce buckling at the bottom of the string, therefore reduce the tubing/rod contact area and in result shall reduce rod and tubing wear. Also the can help to balance the whole unit [5].

The Downhole Pump

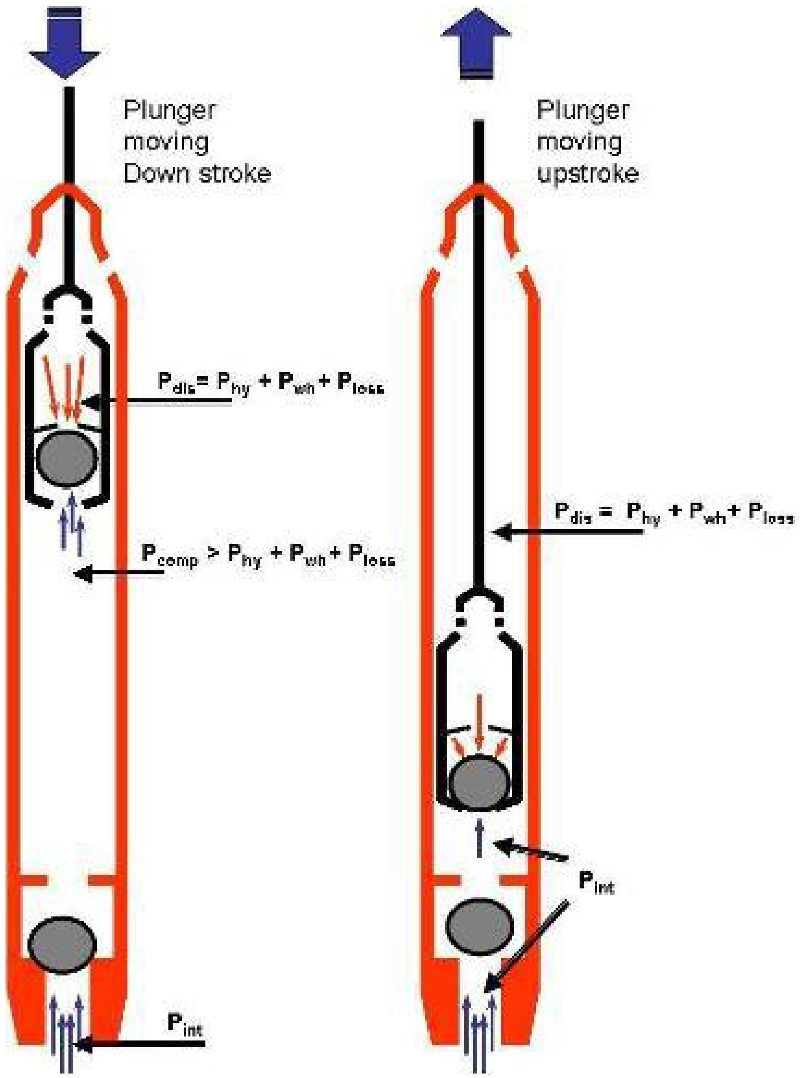


Figure 2: Downhole Pump Pressures [7]

The downhole pump basically is composed of a pump barrel and a pump plunger. The pump plunger normally contains a travelling valve, a standing valve is installed into the pump barrel. Figure 2shows the pump during up- and downstroke. The plunger starts to move upwards, when at the beginning of the upstroke a differential pressure is created across the travelling valve. The pump has to overcome the discharge-pressure p_{dis}, which is the sum of the hydrostatic pressure of the fluid column p_{hy}, the wellhead pressure p_{wh}, and the pressure losses in the tubing p_{loss}. Due to this differential pressure the valve closes and the fluid in the plunger is forced upwards. The upstroke movement forms two regions within the pump barrel: The void space below the upmoving plunger and the space above the plunger. The void space below the plunger is a low-pressure region. Due to the pressure difference between this region and the higher pressure from outside the pump p_{int} a differential pressure exists across the standing valve and forces this valve to open. Therefore it is possible for the wellbore fluids to enter the pump [7].

At the beginning of the downstroke, so when the plunger has reached the top of the barrel and starts to move downwards again, the pressure within the pump increases and gets higher than the outside pressure, forcing the standing valve to close. Due to the downhole movement of the plunger the fluid inside the pump is compressed and the therefore the fluid pressure below the plunger (p_{comp}) exceeds the p_{dis}. A differential pressure across the travelling valve is created and the valve is forced to open due to the differential pressure Δp. Therefore fluid can enter the plunger. At the end of the downstroke the pressures equalize and the travelling valve is closing [7].

Rod pumps can be devided in three big types: Tubing pumps, where the pump barrel is attached to the tubing, the plunger is attached to the sucker rod and has to be run into hole in a separate run. This type provides the largest and strongest pumps, nevertheless they are problematic for work over due to the fact that for service both, tubing and rods have to be pulled.

At insert pumps both, barrel and plunger, are attached to the sucker rod string and therefore the whole pump can be set in one run. This type of pump is designed for smaller volumes, but easier to service than the tubing pumps. The last and less common type of pumps are casing pumps, which is a special type of insert pump with a seat in the casing. Other differentiations between the several API Pump Types will not be necessary for the understanding of this Thesis [5].

Electric Submersible Pumps (ESPs)

ESPs are downholepumps consisting of an electric motor and a multistage centrifugal pump which are normally deployed on the tubing string (cable or coiled tubing deployed is also possible) and operate at the means of centrifugal forces applied on the to-be-produced fluids. Thereby an impeller imparts radial velocity to the fluid which is converted into pressure when the fluid passes the diffusor part of the pump (Figure 3)[5].

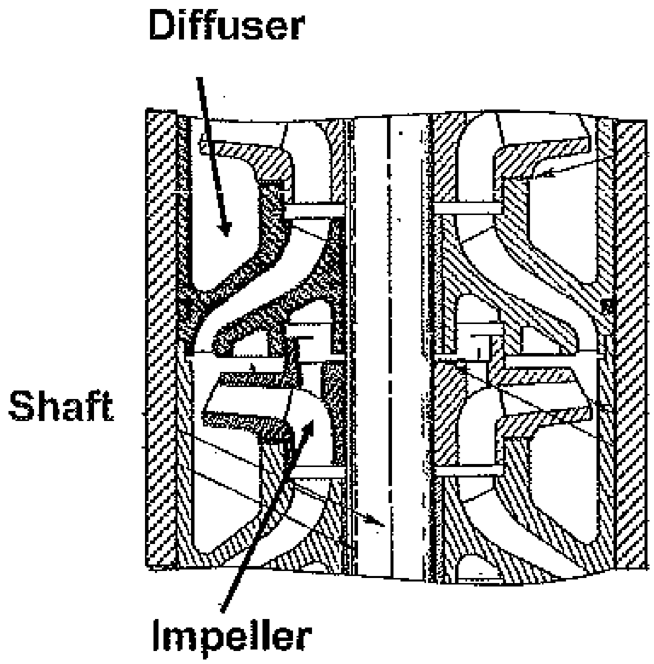


Figure 3: ESP main components [5]

Every stage is just able to overcome a certain head (in ft or m) in the borehole, so for all ESP installations the number of stages has to be calculated in order to pump the fluid up to the surface[5].

Figure 4 shows a schematic ESP Completion.The downhole motor and surface control and transformer are connected by electric power cable. The submersible motor is the driving force that rotates the pump. Due to the fact that the ESPs are very sensitive to free gas in general.For GLRs ≥ 10% a single stage gas seperation is required. The wellhead has to be designed for a cable conduit[5][9].

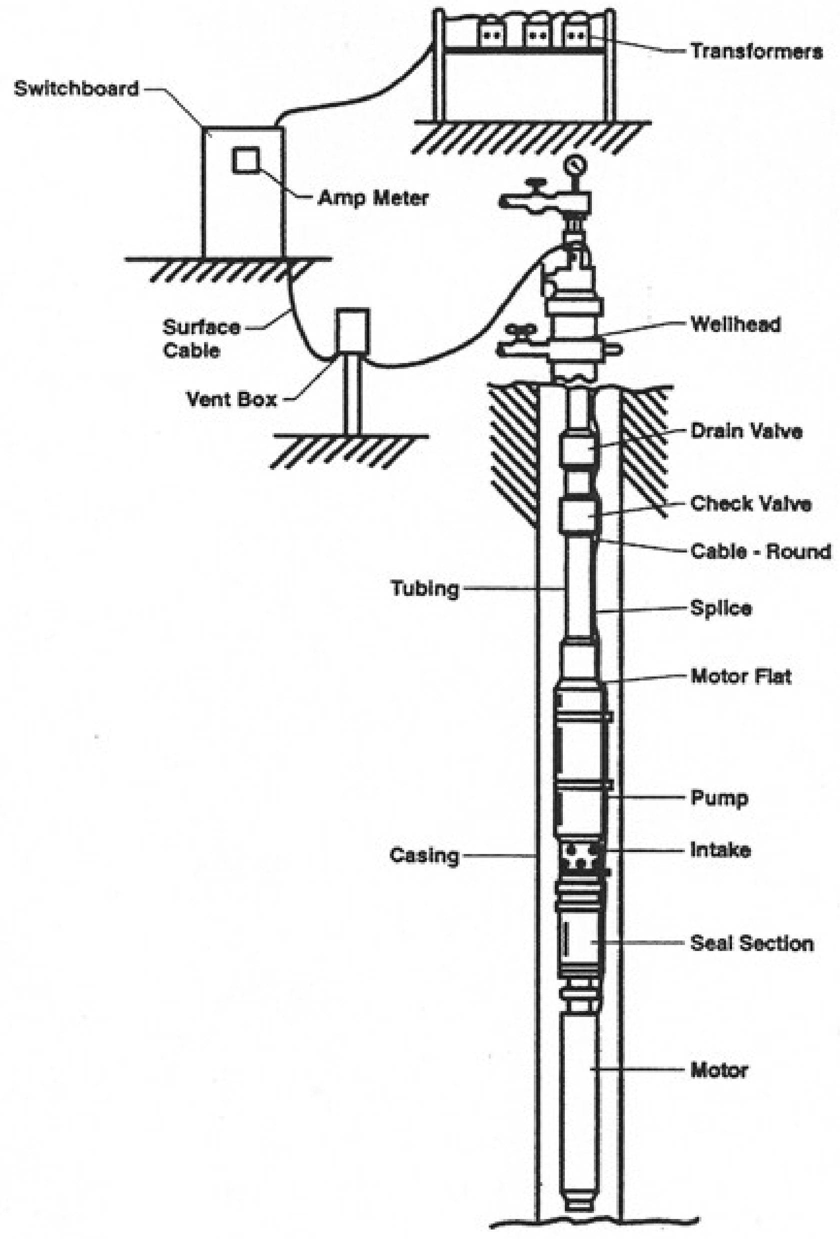


Figure 4: ESP Completion [8]

Progressive Cavity Pumps (PCPs)

The PCP is a rotating positive displacement pump. It transfers fluid by means of progress through a sequence of fixed shape and separate cavities in the elastomer stator by the rotating movement of the rotor which is excentrically turned from the suction to the pressure side. In the basic configuration the rotor is made of steel and has the form of a single helix, the stator has the internal shape of a double helix and is made from an elastomer.Due to the difference single/double helix (the so called lobe ratio, for basic configuration it is 1:2) of rotor and stator cavities are created. The cavities taper down toward their ends and overlap with their neighbors, guaranting a continuous, non-pulsation flow[5][11].

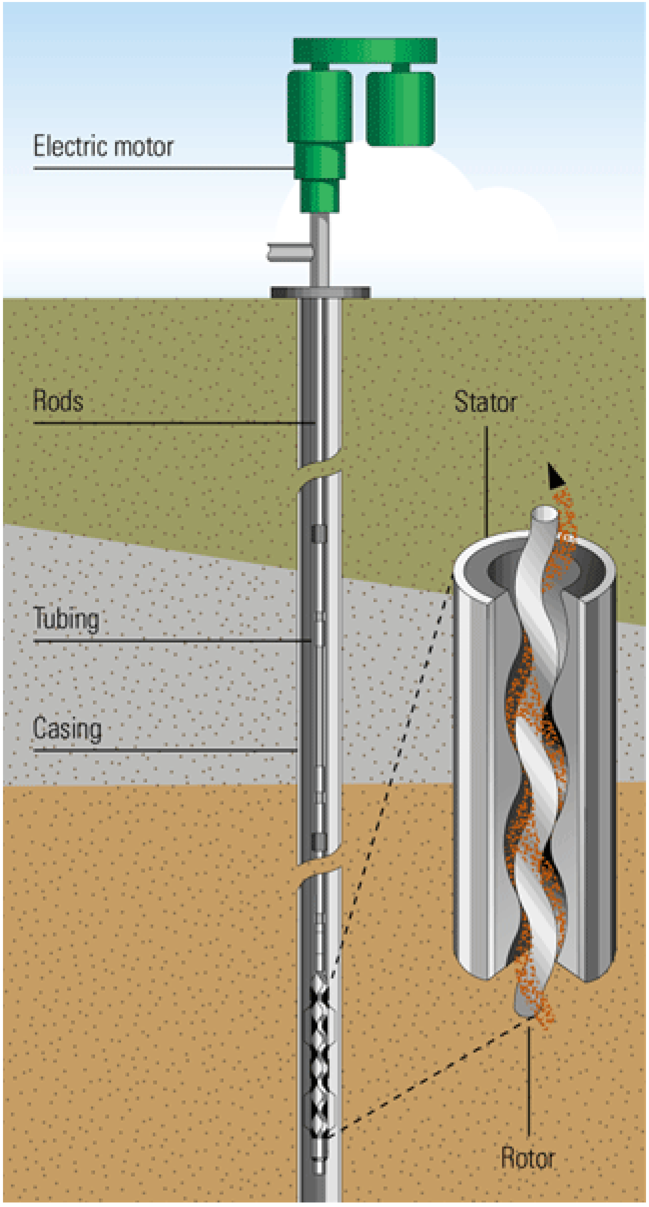


Figure 5: Progressive Cavity Pump Completion [9]

Several improvements of the PCP for oil well applicationsyielded to the conclusion that a lower rotor/stator lobe ratio can increase the production rate at same speed [rpm]. Therefore it is also possible to use a double helical rotor and a triple helical stator (lobe ratio 2:3), which increases the production rate and this decreases the operating costs per barrel of fluid pumped [11].

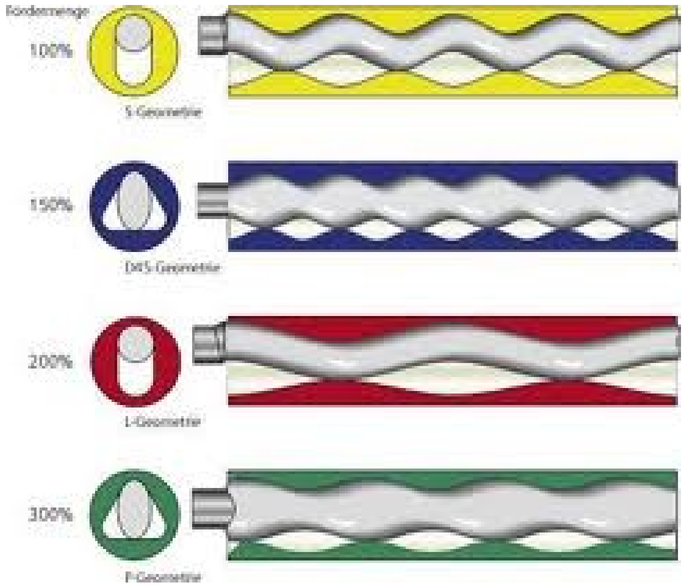


Figure 6: PCPs: Geometry Differences [12]

In a classic application for oil wells the stator is attached to the tubings and the stator is attached to sucker rods with a polished rod on top. The well head therefore has to be equipped with a stuffing box to provide a hydraulic seal between well and surface. The sucker rods are rotated by an electric motor, which is installed at the well head from surface or by a downhole electric motor. The production rate is proportional to the rotations per minute [rpm][5].

Gas Lift

Fluid production is achieved by injecting gas into the production string through one or more gas lift valves when applying gas lift . The gas flows down the well through the casing or (in case of casing leakage) is brought downhole by an injection line and enters the production tubing through the valves. The injected gas mixes with the to-be-produced fluid and decreases it's flowing gradient and therefore lowers the hydrostatic weight of the fluid column and as a consequence the bottom hole flowing pressure. The increased pressure drawdown that comes with high gas injection rates results in higher production rates[5] or if the hydrostatic head is higher than the reservoir pressure this allows a continuous production. It is noted that a gas lift completion requires a packer whereas the other artificial lift methods may be packerless.

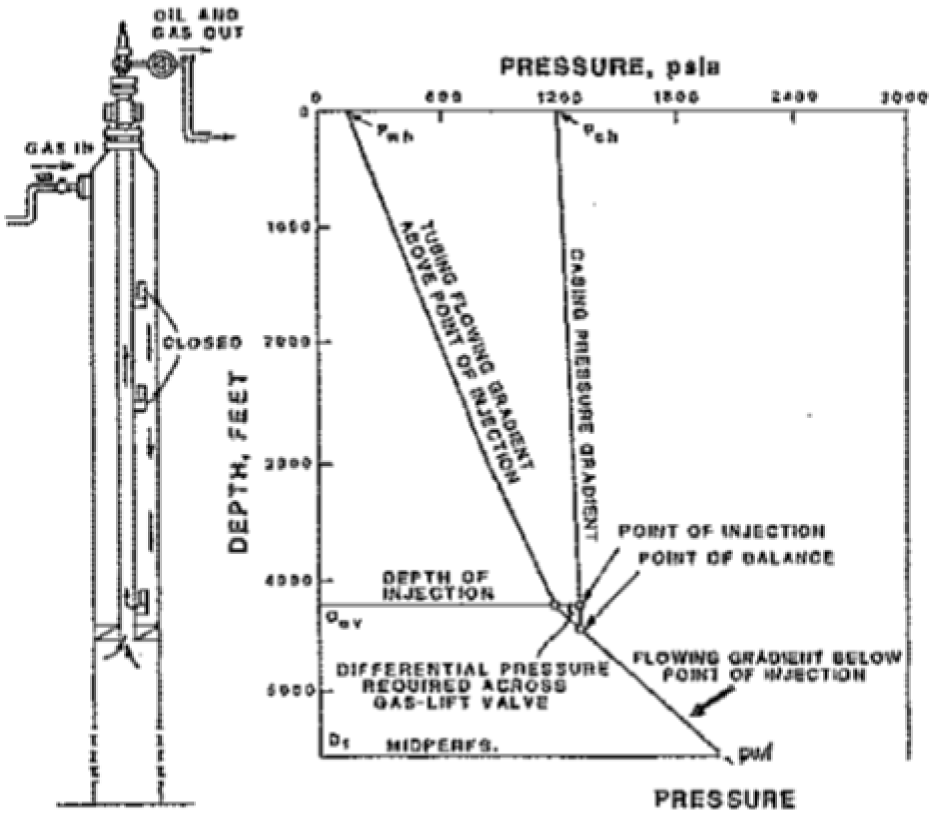


Figure 7: Gas Lift Principle [5]

Figure 7 shows the operating principle of a gas lift installation. The system has already started, the whole injection gas flows through the lowest injection valve. It can easily be seen that the flowing gradient below the point of injection would not be steep enough to provide flow (pressure) at the well head. When gas is flowing down the annulus casing pressure equals the tubing pressure at a certain point, the pressure balance point. Due to the fact that most of the gas injection valves are operated by the pressure difference between casing and tubing the optimum injection depth is slightly above the the pressure balance depth. The injected gas lowers the pressure losses in the tubing (as the tubing flowing gradient above point of injection shows), providing a higher production rate [5].

Basically two types of gas lift exist: Continuous gas lift, where gas is injected continuously to produce the production fluid and intermittent gas lift, which is used to unload wells which do not have continuous high fluid inflow. Intermittent gas lift is a cyclic artificial lift method which produces a significant fluid slug each cycle. The injection GLR required to apply this method is generally greater than the one for continuous installation [5].

Plunger Lift

Plunger lift is a cyclic method of artificial lift that utilizes the well's own energy to produce the reservoir fluids which the well normally cannont expel with natural flow. Therefore it is basically used for liquid loaded gas wells. The plunger thereby is used to establish an interface between liquid accumulated in the production tubing and the reservoir or annulus gas pressure which is used to lift the fluid [5][13].

At the start of each cycle the well is shut in and the plunger then falls through the accumulated fluid to the bottom of the well (it is recommended to install the tubing in a way that the end of the tubing is at the top of the upper third portion of the perforated interval). There are basically two possibilities to re-open the well again: pre-set time or pre-determined pressure at a control panel. The surface pressure is drawn off into a gas gathering system or another low pressure point, thereby creating a differential pressure across the plunger. As a result the plunger starts to rise through the tubing taking the accumulated fluid with it [13].

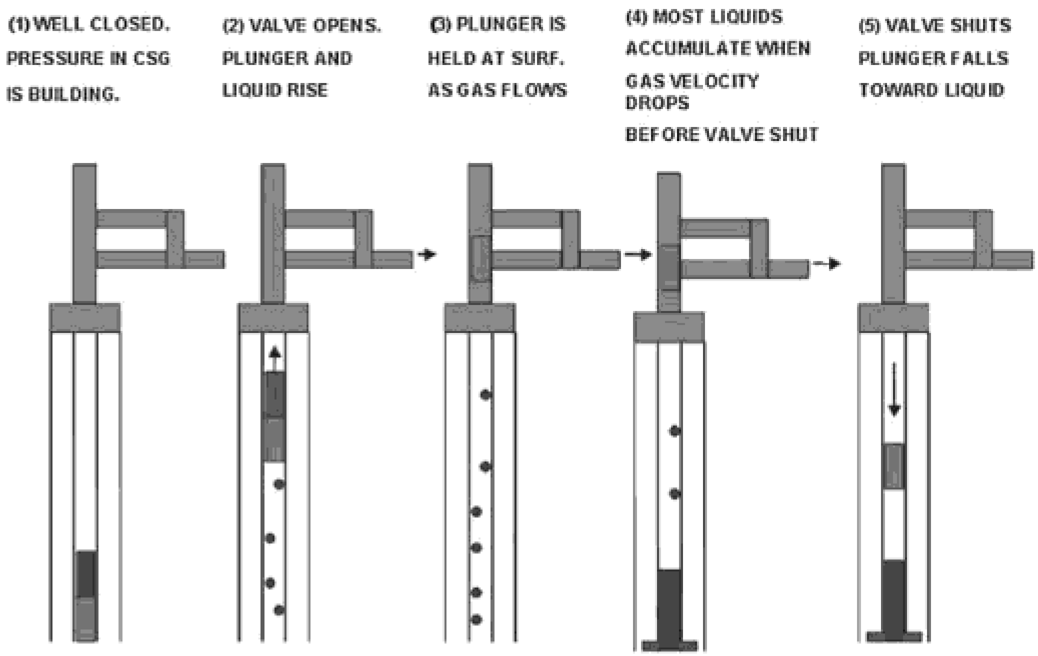


Figure 8: Plunger Lift Principle [14] [p. 128]

The main application of plunger lift systems is de-watering of gas wells.

Foaming

Foaming is a possibility of well de-liquification. Especially in wells with a very low gas rate, liquid loading is a problem, due to the fact that the gas pressure is not high enough to transport the accumulating liquid up to the surface. The principle of foam as a de-liquification method for gas wells is that foam provides a larger surface area than normal water gathering at the bottom of a well. Gas is held within the bubbles, decreasing the density of the whole mixture. Also gas slippage is reduced.

The foam effect on the production of liquids is described by:

$$V_t = \frac{1.593\ \sigma^{\frac{1}{4}}(\rho_l - \rho_g)^{1/4}}{\rho_g^{1/2}}$$

V_t (in ft/sec) hereby describes the critical velocity of gas, ρ (in lbm/ft³) indicate the density of a fluid, subscripts l and g stand for liquid and gas. σ (indynes/cm) is the surface tension between gas and liquid. The critical velocity of gas hereby means the gas velocity which is sufficient to take the liquid droplet within the gas stream to the surface.

Foam basically reduces the surface tension and therefore reduces the required critical velocity. Foam also will reduce the density of the liquid droplets. A rule of thumb is that foaming the water will reduce the critical veloctiy about two-thirds.

The percentage of gas in the foam mixture at operating pressure and temperature is called foam quality.

Application possibilities of foaming agents:

Three methods exist to bring the foaming agent (surfactant) into the well. The simpliest method is to drop soap sticks down the tubing, the second to apply batch treating down the annulus which can only be done if there is no packer in place or as third possibility, to use a chemical injection line, the so called capillary string for injection of surfactants [14].

Conventional Hydraulic Pumps

Hydraulic pumping applies Pascal's principle to active wells by transmitting pressure generated on the surface to the bottom of a well by a working fluid in order to actuate e.g. an engine with a reciprocating piston driven by a power fluid connected by a short shaft to a piston in the pump end or a jet pump equipped with a nozzle that leads into a venturi in order to carry the fluid from the pay zone by means of the working fluid.

Reciprocating Piston Pumps

The reciprocating piston pump consists of an engine which drives a closely connected piston pump. Two configurations of reciprocating piston pumps exist: One type with a closed power fluid system and one with an open power fluid system. The basic difference is that the high pressure power fluid which drives the engine can flow up to the surface again in a separate tubing (closed system) additionally to the production tubing or mixed with the well production fluid in one production tubing.

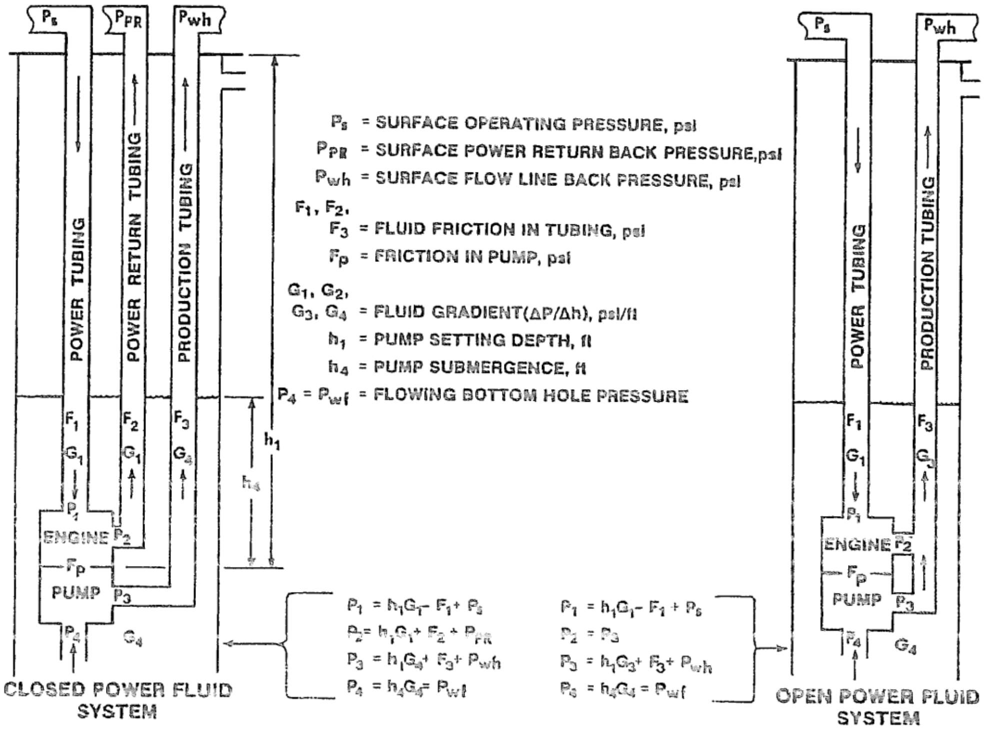


Figure 9: Open and closed power fluid systems [5]

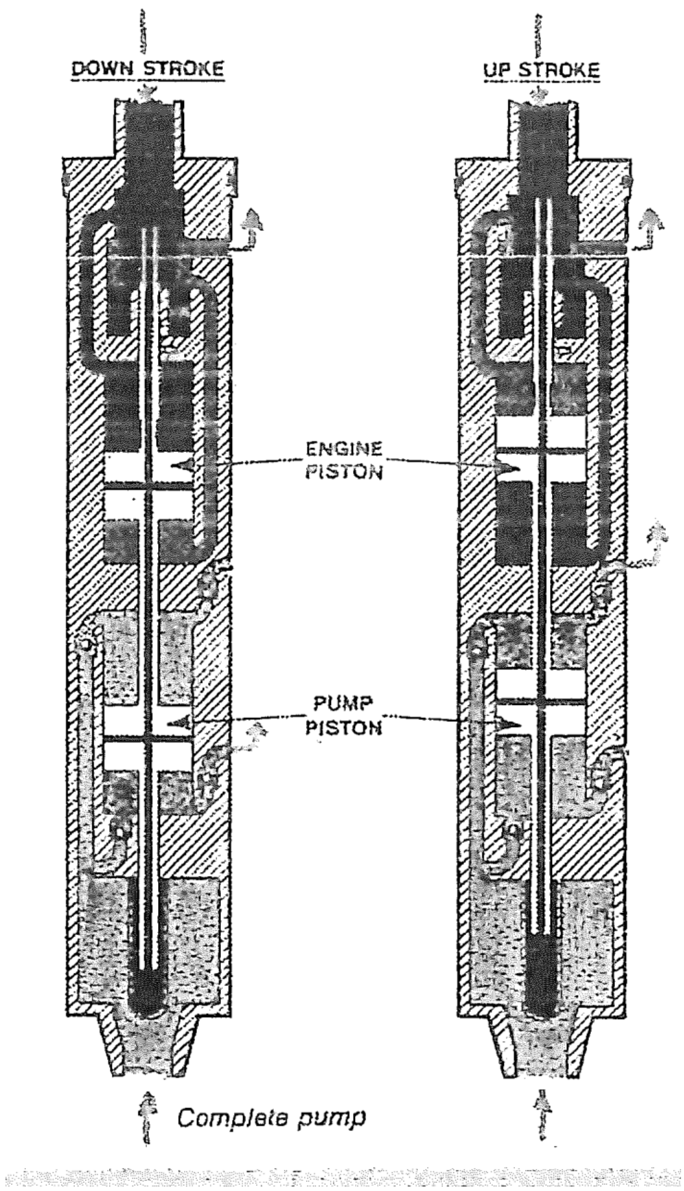


Figure 10: Reciprocating Piston Operating Principle [5]

The reciprocating piston pump is an artificial lift systems which can be easily automated and remote controlled and shows a compact well head that can be covered in sensitive areas. An application in very deep wells is possible. Also no rotating components exist in the system[5].

Jet Pumps

As shown in Figure 11 the jet pump system consists of a power fluid tubing, a downhole nozzle/diffuser part and the main production tubing. The power fluid (p_1, q_1) is pumped at high pressure and low velocity down hole to the nozzle. Figure 12 shows the different pressures and flow rates at the nozzle. Here the high pressure is converted to high velocity, low pressure due to the decrease of diameter. When this pressure becomes lower than the pressure in the suction pathway (p_3) production fluid is drawn into the throat. The production fluid (p_3,q_3) is entrained into the throat together with the high velocity jet. The both fluids mix within the throat.

The mixed fluids are slowed down again by the diffuser, resulting in an increase of pressure (p_2), which rises to a sufficient value to lift the fluid to the surface[5].

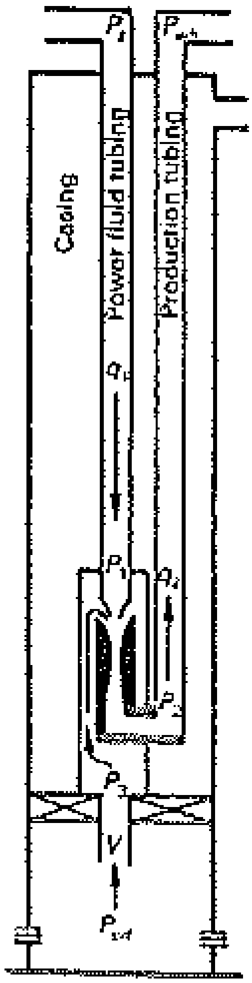


Figure 11: Jet Pump [5]

To meet the necessities of different production fluids, different pressure regimes and different lifting heights, the nozzle-throat-diffuser parts are available in different sizes to allow power fluid rate and pressure to be varied[5].

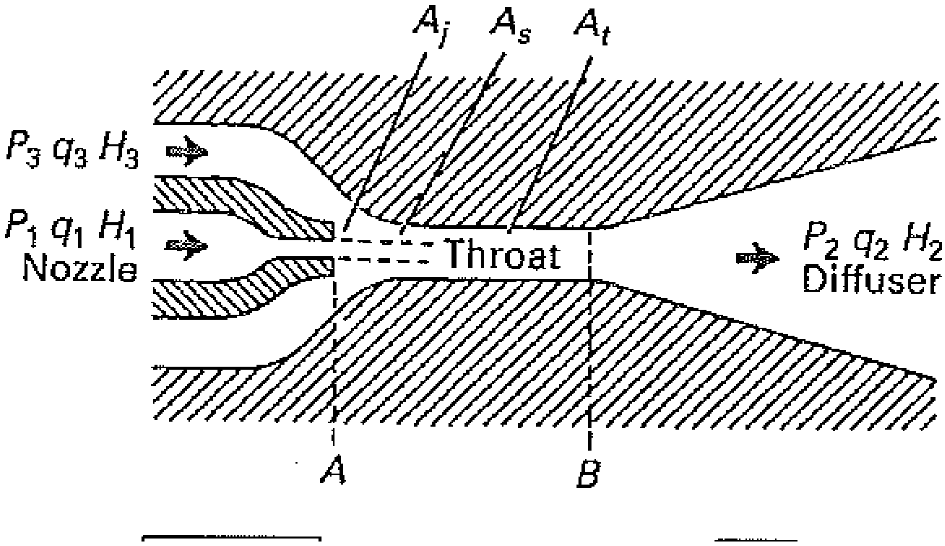


Figure 12: Jet Pump Nozzle [5]

Comparison of conventional Artificial Lift Systems

Appendix 1 shows a comparison of the conventional artificial lift systems, including Progressive Cavity Pumps (PCPs), Electric Submersible Pumps (ESPs), Jet Pump, Gas Lift, Pumpjack driven Sucker Rod Pumps, Rotaflex Long Stroke Pumping Unit Sucker Rod Pump, and the Beam Gas Compressor as production increasing tool.

The comparison includes pump characteristics, necessary properties of the to-be-produced media and the ability of the pump to handle them, necessary well specifications, the influence of certain reservoir properties, a short description of the single systems and an economics.

Also shown is the percentage of the single systems within the worldwide artificial lift market and the type of well for which they can be used.

Pump characteristics include the range of pump speed (rpm), the possible achievable flow rates and the ability of the single systems to handle high and low volumes. The “Produced Media”-Section describes the composition of the fluids which can be produced with this type of pump, e.g. Gas Liquid Ratio, Water Cut, Fluid Gravity and viscosity, formation sand production, the ability to handle highly corrosive fluids (including H_2S and CO_2) as wells as the possibility to do a scale treatment in the well with installed pump.

The section “Pump Abilities” shows the possibilities of well intervention, pump efficiency, run life of the pump, setting method, flexibility, reliability of the single pumps as well as eventual HSE Problems.

Also described are Well Specifications which are necessary to complete a well with a certain artificial lift method. This includes max. setting depth, dogleg severity, bottom hole temperature, casing size limit and restrictions in tubing size as well as flowing bottom hole pressure. Also described is the maximum drawdown which can be achieved with each system.

Because not every pump system can be used in combination with all possible reservoir specifications, the comparison also shows which bubble point, reservoir pressure decline and flow stability are optimum for each method.

A short description of the whole systems is also included.

The last part compares economic factors as CAPEX and OPEX. It has to be mentioned that the values for the economic comparison come from different references and have not been taken from wells with equal depths and flow rates. Therefore the information of these numbers has to be used with care. For a real comparison values would have to be taken from wells with equal conditions.

Also for some systems not all values have been available. The table shall give a short overview man may be used as introduction to the main topic of this thesis.

Comparison of conventional systems for De-Liquification of Gas Wells

Some of the artificial lift systems described above can also be used for the de-liquification of gas wells, e.g. Progressive Cavity Pumps or Sucker Rod Pumps. The Plunger Lift which is contained in the table below can also be used for stripper oil wells, but normally is a de-liquification method. Foaming is a method exclusively used for the de-watering of gas wells.

Comparison of conventional systems for de-liquification of gas wells				
	Foaming		Plunger Lift	
Units	basic	max	basic	max.
Manufacturer				
Flow Rate [m^3/d]	80 *		0.16-0.8	32
Produced Medium	De-w atering gas w ells		De-Watering Gas Wells	
Sand Production	good		fair	
Gas Liquid Ratio	excellent;		300 [scf/bbl/1000 ft]	
Water Cut	w ater and gas; just low hydrocarbon amount		100% w ater	
Fluid Gravity	>8°API		>15°API	
Liquid hydrocarbon handling capability	may cause problems because hydrocarbons act agains foam-building		no problem	
Temperature [°C]	204		288	
Setting Method	Dropping soap sticks in tbg., Batch treating dow n the annulus, Lubricating a capillary string dow n the tbg.; Capillary Unit		Wellhead catcher or w ireline	
Completions	additional Capillary String:			
Completion specification [in]	1/4 or 3/8			
H_2S, CO_2/ Corrosion handling	excellent		excellent	
Dogleg severity	N/A		max. 80°	
Depth [m]	6,705		2,400	5,790
CAPEX			€ 3,800-4,500	

*80 m^3/d is given by Weatherford as max. flow rate for “capillary techniques”.

Table 2: Comparison of Plunger Lift and Foaming

As shown in 80 m^3/d is given by Weatherford as max. flow rate for “capillary techniques”.

Table 2 both methods of de-liquification of gas wells can be used for relatively deep wells, especially foaming can be used to a depth of almost 7,000m. Nevertheless, the amount of liquid that can be lifted by these techniques is limited. Plunger lift has its normal rate range up to 0.8 m^3/d, for foaming itself precise numbers are hard to derive.

Hydraulic "Pump Jack" Systems

Hydraulic Artificial Lift Systems are devided into two categories: Hydraulic Submersible Systems, where the hydraulic fluid is pumped down-hole and driving a down-hole pump – this thesis describes a piston and a diaphragm down-hole pump –and Hydraulic Drive Systems, which basically substitute the mechanical "Pump Jack" at the surface, but uses the same down-hole completion.

This Thesis describes three of these "Hydraulic Pump Jack" systems. All of them are sucker rod pumps, as used in the oil industries for many decades. Two of these drives – one produced by Bosch Rexroth and the second produced by a Canadian company named Ecoquip – are conventional sucker rod pumps down-hole, the third one is designed as a long-stroke sucker rod pump.

Electro-Hydraulic Drive System

Bosch Rexroth has been working on hydraulic drive systems for sucker rod oil-production pumps since the early 90's of the last century. These systems have been used by operators mainly in South and Latin America, in Venezuela, Ecuador and Colombia. The manufacturer calls its hydraulic drive system series "R". Therefore R7 is the seventh hydraulic drive system developed by Bosch Rexroth.

Bosch Rexroth jointly develops the R7 in co-operation with Wintershall Holding GmbH. One system is installed at Wintershall's Oil Production Facility in Landau/Pfalz, Germany. The well, which was shut-in for some time due to inflow-restrictions, has been specially prepared for this test: At first a conventional mechanical drive and the down-hole pump have been installed to provide best-possible comparison values for the test operation of the hydraulic drive[17].This system is the first R7 installed in Europe, two other ones have been installed in Venezuela, one in Ecuador, both not working currently, six systems are working in Colombia and one in China. Bosch Rexroth plans to put one system in operation in Kazakhstan next year[1].

Main Principle

Components

The system basically consists of a hydraulic cylinder mounted to the wellhead and a hydraulic power unit, which is placed outside the ATEX-zone, as shown in Figure 13[17].

The polished rod also acts as cylinder rod. It is connected to the rod string within the tubing.To provide the optimum seal for the well, a 0.90 mhigh frame is flanged to the wellhead and the hydraulic cylinder is mounted on the frame. By using this way of installation, the wellhead is sealed by the conventional stuffing box, and the hydraulic cylinder uses a separate sealing system composed of a wiper and a seal. The hydraulic cylinder is a double-acting cylinder which is driven from one side – only the upstroke is hydraulically driven. For the downstroke the weight of the rod string is used. Figure 13 shows the system installed in Landau. The right line, leading to the top of the cylinder, is a hydraulic line, which is able to pressurize the cylinder on the top side up to 30 bar. Due to the fact, that just the rod weight drives the downstroke, it is just used for venting. The left line, leading to the top of the device, contains the electrical cables used to power the position measuring sensor of the cylinder rod.This sensor uses a magnetic – non –touch technology, which according to the vender could measure positions as accurate as 2µm (whichbasically is not needed in the petroleum industry). Therefore the cylinder rod is produced with a bore, which leads down almost the whole cylinder length. Here the position measuring sensor is installed[1].

The hydraulic aggregate consists of an axial piston unit, an electric motor with integrated flywheel mass and the monitoring and the system control [17].

It is equipped with a pressure sensor, a temperature sensor and to provide full flexibility a cooling and a heating system [1].

Figure 13: Hydraulic Cylinder on Wellhead, Landau [17]

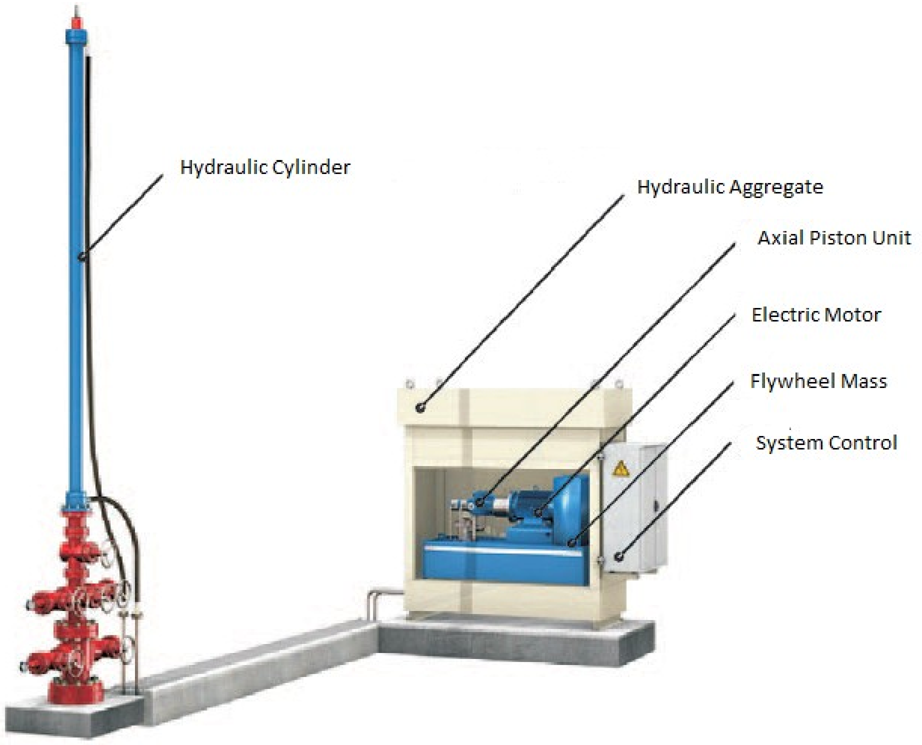


Figure 14: Hydraulic Cylinder and Hydraulic Aggregate [17]

Basically, two hydraulic lines and one electrical line are connected from the hydraulic aggregate to the cylinder. One hydraulic line is pressurized (in the Landau application up to 200 bar) to drive the cylinder, the other one leads from the hydraulic oil tank to the top of the cylinder and is used for venting and lubrication. It is intended to provide a permanent oil mist in the upper cylinder chamber to lubricate the piston head and act as corrosion protection. According to the manufacturer a direct venting would be the technically easier way, but includes the risk of cylinder-corrosion. Addtionally this line has a safety function: In case of piston head seal damage the hydraulic oil can directly be led to the hydraulic oil tank. Also an auxilliary oil pump exists in the system. If the cylinder doesn't move during the start-up-process, this auxilliary pump can pressurize the top chamber and assist the cylinder movement [19].

Due to the length of the hydraulic lines which is necessary due to the ATEX zones, the pressurized line needs a bypass to ensure a proper circulation of the hydraulic oil. This installation is shown inFigure 15.

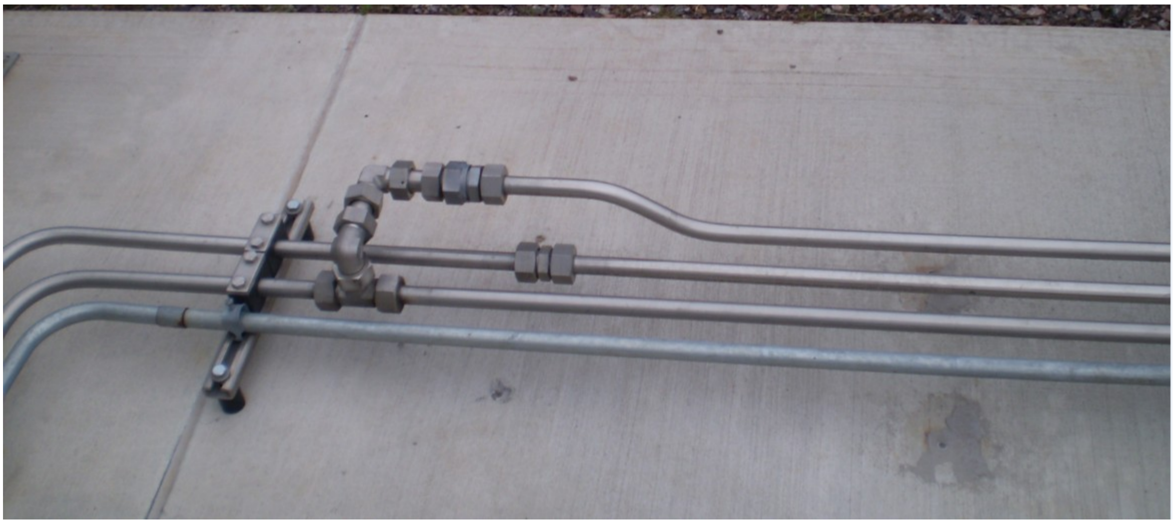


Figure 15: Bypass for the hydraulic pressure line [1]

Working Principle

For the upstroke movement of the cylinder rod, the axial piston unit acts as a pump. It pumps the hydraulic fluid into the chamber A of the cylinder. Therefore the cylinder rod, and connected to it the rod string, is driven upwards. Figure 16 shows the inside schematic of the hydraulic cylinder assembly. Chamber B normally is not pressurized even if it is possible to apply pressures up to 30 bar.

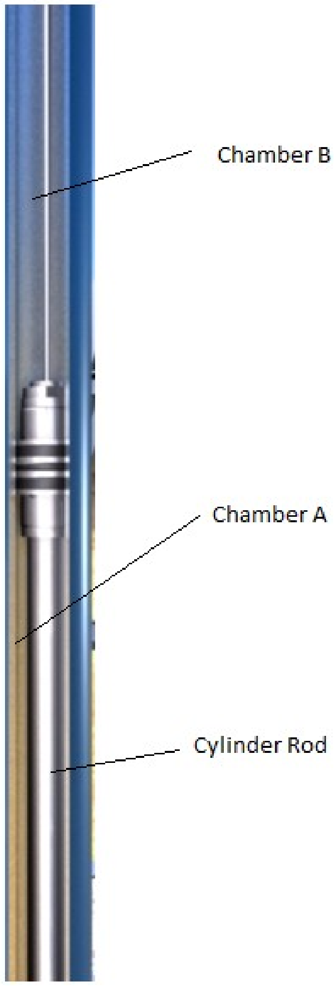


Figure 16: Hydraulic Cylinder Scheme [18]

According to Bosch Rexroth, in Landau it was discussed that thechallenge when dealing with hydraulic drives for sucker rod pumps is the energy efficiency of these systems. Quite some energy is needed to pressurize the hydraulic oil for the upstroke and – if no technical arrangements in form of potential energy storage are made – is set free again during the downstroke. This can be up to 40-50% of the total energy consumption. One method nearly every producer uses is an energy re-injection into the public electricity grid. But even this doesn't increase the energy efficiency very much compared with mechanical systems.

Bosch Rexroth therefore developed a system with an axial piston unit and a flywheel mass, as shown on Figure 14:

During the downstroke potential energy is set free by the downwards movement of the rod string. This energy drives the axial piston unit which now acts as a motor. The electric motor and the flywheel mass are accelerated to network-synchronous speed, which stores the energy mechanically[1].

While moving the rod string upwards, the flywheel-speed is decreasing. This frees the energy which was stored during the downstroke and assists the electric motor power the axial piston unit. The electric motor comprises up to 10% slippage, which allows driving the motor with a larger variability of speed [17].

During designing the R7, one of the main objectives has been to develop a system with variable stroke length. To control the stroke length and the points, where the movement changes from up- to downstroke and back again - the so called direction-change-points - normally a position measuring sensor is installed. The cylinder is longer than the needed stroke length. So there is a little safety design margin inside the cylinder, and the cylinder rod doesn't touch the top or the sealing elements at the bottom of the cylinder. The stroke length itself is variable[1].

As mentioned above the hydraulic aggregate is equipped with e.g. a temperature sensor. This sensor gives signals to the control system. Here limits for maximum and minimum allowable temperatures can be set. If the temperature reaches the upper limit, the cooling system is activated automatically. The same principle holds the lower limit and the heating system[1].

A pressure sensor is installed on the hydraulic aggregate. This pressure sensor also transmitsa signal to the control system. Here the data is used for two functions:The main function is a safety function to prevent hydraulic fluid losses in case of a leak: if the pressure decreases down to a pre-set level, e.g. if a leak in the hydraulic lines occurs, the system shuts down. According to the manufacturer a maximum of 30 l can leave the system in case of a leak[1].

The other function of the pressure sensor is an overload protection of the sucker rods. In case of stuck pipe due to sand or solids in the down-hole pump or the tubing, the pressure sensor signals a higher hydraulic pressure needed for the upstroke. If this pressure increases to a pre-set, level, the system activates a creep-speed mode. In this case the velocity is decreased and the system tries to relieve the stuck rod string. In the same situation a mechanical drive would shut down[17].

Fatigue strength

One of the attractive advantages of the R7 is a "free adaption" of speed for upstroke and downstroke, that means upstroke and downstroke velocities do not have to be the same, because the strokes are not bound to the sine-shaped movement of a mechanical pump jack. This is shown in Figure 17[17].

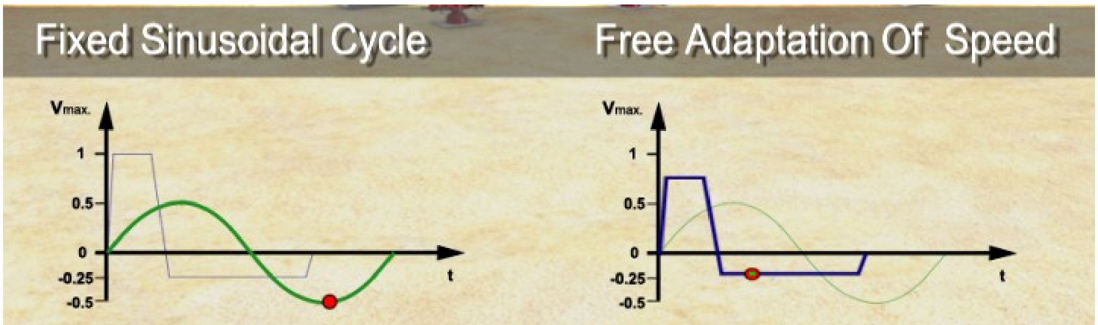


Figure 17:Velocity over Time-Diagram [18]

However this operation also imposes a hazard: The changes in direction are more abrupt, in reality not that sharp-edged as in Figure 17, the curve is not so smooth as for a mechanical drive. This may additionally stress the rod string due to the fact that the conventional parts of a pump jack's rod string are calculated and manufactured for a cyclic, sine-shaped loading scenario [20]. If the movement of the rods is not bound on the counterbalanced, sine-shaped movement of a conventional pump jack it is possible to increase the upstroke velocity. This also increases the acceleration at the beginning of every upstroke movement, and therefore applies higher loads on the rod string. Bosch Rexroth therefore investigated the fatigue strength of the rods from the point of higher velocity scenarios and consequently from the point of higher acceleration at the turning points. It has been found that the limit have to be calculated for every single unit and well conditions due to these values depend strongly on the forces, number of cycles and the specific rod strings. As a matter of fact the unit in Landau operates perfectly within the limits and it has been calculated that these values cannot be reached at the Landau well [19].

Installation

Bosch Rexroth completes the container with hydraulic aggregate and control panel in their factory and delivers it directly to the well site. The frame is then flanged onto the well head and the hydraulic cylinder is mounted.It is important to bring the cylinder axis in line. Then the electrical connections have to be made, the supply voltage has to be connected and the measuring cable has to be laid between the hydraulic cylinder and the control panel.

Then the hydraulic lines between the hydraulic aggregate and the hydraulic cylinder have to be made. At the test well in Landau these are stainless steel lines which had to be adapted one by one[19].

Installation Schedule

Job	Personnel	Time
Installation of frame and hydraulic cylinder	3	2-3 [hrs]
Electric connections	1	2-3 [hrs]
Hydraulic steel line connection	2	1 ½ [d]
Alt.: hydraulic hose connection	2	½ [hrs]

Table 3: Installation schedule for R7 in Landau [19]

Control, Monitoring and Diagnostics

The whole system offers a very high level of flexibility. As mentioned above, a position measuring sensor, pressure and temperature sensor is connected to the control system, to provide all important data for full flexibility. Also the actual polished rod load is continuously measured (Figure 18). At the control station inside the noise protection container near the hydraulic aggregate, it is possible to select stroke length, upstroke/downstroke velocity separately, emergency shut-down pressure, upper pressure level for activating creep-speed mode, temperatures for activating/de-activating the cooling and heating system etc[1].

The production situation of a pump/well can be shown in a force/displacementgraph. These so-called dynamograms show the functionality of the valves, the filling grade of the pump, etc.

Bosch Rexroth has developed a continuous real-time monitoring and diagnostic program which goes along with integrated level-measuring[1].

As mentioned above the combination of pressure and displacement measurement also provides the possibility for level measurements. This is important due to the fact that conventional level measurement devices are not applicable at a well equipped with Bosch Rexroth R7 hydraulical pump drive[19].

Figure 18: Display of the control station[1]

Basically it ispossible to start/stop or pre-set the whole system remotely . This makes it possible to react very fast on changing production conditions at the well [20].

Possible Configurations

The hydraulic aggregates are available in different power classes varying from 26.4 kW to 90 kW.

The following table shows the standard configurations of R7:

Type R7-	**Comb. 1: Stroke length (in)/spm**	**Comb. 1: Stroke length (cm)/spm**	**Comb. 2: Stroke length (in)/spm**	**Comb. 2: Stroke length (cm)/spm**	**Comb. 3: Stroke length (in)/spm**	**Comb. 3: Stroke length (cm)/spm**
365 -	144/6.0	366/6.0	168/5.0	427/5.0	192/4.5	488/4.5
305 -	120/6.0	305/6.0	144/5.0	366/5.0	168/4.5	427/4.5
305 -	120/5.0	305/5.0	144/4.0	366/4.0	168/3.5	427/3.5
256 -	120/5.0	305/5.0	144/4.0	366/4.0	168/3.5	427/3.5
256 -	100/4.5	254/4.5	120/4.0	305/4.0	144/3.5	366/3.5
213 -	100/4.0	254/4.0	120/3.5	305/4.0	144/3.0	366/3.0

Table 4: Standard-Electro-Hydraulic Drives I[17]

Type R7	**Power (kW) @ 50 Hz**	**Weight (lbs)**		**Weight (kg)**		**Max. Production (BFPD) for a 2 in pump**	**Max. Production (m³/d) for a 2 in pump**
		Max.	Dyn.	Max.	Dyn		
365	75.0	36,500	29,200	16,556	13,245	430	68
305	55.0	30,500	24,400	13,835	11,068	370	59
305	45.0	30,500	24,400	13,835	11,048	290	46
256	37.0	25,600	20,480	11,612	9,290	290	46
256	30.0	25,600	20,480	11,612	9,290	230	37
213	22.0	21,300	17,040	9,662	7,729	210	33

Table 5: Standard-Electro-Hydraulic Drives II [17]

The whole system weighs less than 3000 kg and (as installed at Wintershall) has a total height of 4 m [1].

Well head requirements

Diameter of the cylinder rod is 45 mm, the polished rod diameter 32 mm. Therefore the conventional stuffing box has to be adapted for the larger diameter, as well as the brass rings inside. The connection between cylinder rod and polished rod moves is located inside the tubing [19].

Health, Safety and Environment – HSE

Due to the fact that hydraulic fluid is pumped under high pressure over the well site into the ATEX- zone some additional HSE aspects have to be considered:The system acts – depending on the well conditions – with very high pressures up to 200 baror more. Hydraulic Pump Jack systems – e.g. the Ecoquip HPJ described below – normally use high-pressure hydraulic hoses to transport the pressurized fluid to the wellhead.The German mining authority has requested the use of stainless-steel lines between the hydraulic aggregate and the hydraulic cylinder. Due to the high pressure and the circulating movement these lines show quite strong vibrations, especially if having small amounts of air/gas in the oil stream. Therefore additional fixation points of the lines are necessary[1].

In the event of a leak the pressure sensor mentioned above transmits a lower pressure value to the control panel. At the panel a critical value for a sudden pressure decrease can be set to initiate an emergency shut-down in case of a leak. So the lowest possible amount of fluid will be lost [1].

Basically, the hydraulic drive improves the HSE conditions at the well site. The system contains no rotating parts, which have to be secured in a special way[20]. Also the portion of free moving polished rod, which could also be a safety hazard e.g. if unauthorized persons enter the site, is very small, only the small part of the polished rod between well head and lower cylinder entrance.

Economics

Item			Costs [€]
CAPEX			63,000
Additional Installation Costs	Electrical Technician, additional personnel, hydraulic oil		2,500
OPEX			
Maintenance	7-8 hrs	Once a year	800-1000
Hydraulic Oil		Once a year	500
Non-productive time	7-8 hrs	Once a year	294 (a)
Electrical consumption	4.5 [kW/h] (b)		Depending on the electricity costs

Table 6: CAPEX and OPEX for R7

(a) The numbers are calculated on the basis of the Wintershall testing-operation of R7 in Landau.

V=3.5 m³/d, wet oil

WC=40%

ρ_{oil}=840 kg/m³

Oil price=500 €/t[2]

(b) The Landau test well is an oil well with inflow restrictions. It has been produced using a conventional mechanical drive before and also during this operation the pump worked at

[2] Number derived from RAG in January 2012

very low efficiency. Therefore the electrical consumption shown in Table 6 is not representative.

Advantages and Disadvantages

Disadvantages

Polished/Cylinder Rods

The cylinder rod acts as polished rod and is connected to the rod string within the tubing of the well below the stuffing box. According to Bosch Rexroth the cylinder rod cannot be manufactured from stainless steel as a conventional polished rod would be. The first failure due to corrosion occurred after one year of operation.

The cylinder rod's surface shows very small irregularities. Because of the direct connection of cylinder rod and polished rod, and due to these unevenness small amounts of hydraulic oil can be transferred to the produced fluid and otherwise. Theoretically it would be possible that this contamination may set down the flash point of the hydraulic oil. Also it could be that solids from the produced fluid may be carried into the hydraulic oil, which may have a negative effect on the sealing elements of the hydraulic cylinder. Therefore it is necessary to change the hydraulic oil after a certain period of time. After four months of operation the hydraulic oil has shown a severe change in color (Figure 19), but a total change of the fluid has not been necessary[20].

Figure 19:Hydraulic oil new/used[20]

Noise emission

The hydraulic aggregate shows high noise emissions. In contrary to a mechanical pump jack, where the noise is depending on the well conditions or are a result of an insufficient lubrication, the noise emissions of the R7 come directly from the motor/axial piston unit. Ihl, Kuznetsov et al show figures in a range of 77 dB without noise protection and 64 dB with noise protection. This means that the operation of this system in residential areas is prohibitive without further noise protection. Even outside of residential areas (the Landau test well is not installed near any houses etc.) it is necessary to put the axial piston unit, the electric motor and the control system in a noise-protecting container[20].

Economics

Another disadvantage is the complexibility of the workover process. Due to the fact, that the polished rod is directly connected to the cylinder rod, the whole cylinder has to be removedin case of a down-hole pump failure. Additionally to the workover rig which is also necessary for repair operations at wells with conventional drive, a crane and a hoisting rig are needed[20].

The workover operations needmore specialized and well-trained personnel. The previous workover processes in Landau have shown that a minimum of 4 to 5 persons is necessary for the workover (compared to 3 for mechanical pump jacks).Due to the complicated process also more time is needed for the workover. 3 hours are needed for de-installation and 2-3 hours for re-installation[1]. In total the system shows higher workover costs and longer downtime. Although - according to Bosch Rexroth - the energy efficiency of the R7 has been improved compared to the predecessor systemsthe energy consumption is about 10% higher than for a mechanical pump jack. The power efficiency of the hydraulic pump in correlation to the conduction losses and the degree of efficiency of the hydraulic cylinder. The previous findings after one year of operation in Landau seem to confirm the findings. The total efficiency of the system will be published after the end of the test operation in Landau [20]. The additional energy needed for the operation of the hydraulic pump drive increases the operational costs for the R7 in comparison to mechanical drives.

Another addition to the operational costs is a complete hydraulic oil change and a change of the filter elements once a year as recommended by the manufacturer[1].

Rod Rotator

One definite disadvantage of the R7 is that there is no rod or tubing rotator used, and according to the manufacturer, to integrate a rod rotator is not possible at all. Even though the Landau well is vertical and has been running since 2010 the protectors of the rod string have showed massive wear and have been replaced in a workover in November 2011. Due to the hazard of a tubing leak because of this excessive wear the tubing has been pressure-tested and found tight[1].

Advantages

Production Flexibility

The above mentioned free adaption of speed is also the biggest advantages of the system. Due to the fact, that every sucker rod pump needs a net positive head for operation, the dynamic fluid level has to be above the pump. Therefore, the downstroke movement which is dictated by the gravity force has to act against the buoyancy, which restricts the downstroke velocity to avoid excessive buckling. At a mechanical drive, the upstroke velocity is bound to the downstroke velocity in a sine-shaped movement. Using a hydraulic drive the upstroke velocity is not restricted anymore by the max. downstroke velocity. This means more strokes per minute and –as a result – a higher frequency is possible (at a same stroke-length and without changing any parts of the system), which means a certain production increase at the same stroke length.Even though this cannot be proved at the Landau well (which has inflow restrictions), the manufacturer and the Wintershall engineers think that this may be the biggest and deciding advantage of R7. The increase in production after downtimes has been estimated at 10% [20].

Also applied at a well with strongly varying production conditions the flexibility of the R7 is an advantage,especially in combination with the real-time conditioning and monitoring. Due to the fact that velocity and stroke length can be changed very easily and without any mechanical changes at the system, quick reactions and optimization of production are possible[20].

Load Protection

Mentioned above is the load protection mode of the system. Hereby the system slows down if the rod string is stuck and tries to relieve the string by continuous movement. Due to the pressure sensor at the hydraulic aggregate the system is able to sense if the string has successfully run free and then changes back to normal load. This may prevent breakage of the rod string components and prevents a sudden shut down of the system [20].

Visibility

One other factor to mention is the small footprint of the system. Mechanical drives have not only a greater height (as shown in Figure 20)but are also more massive and better seen than the slender silhouette of the hydraulic cylinder.

Figure 20:Difference in footprint between a mechanical pump jack and the R7[18]

No Foundation needed

The hydraulic cylinder is directly flanged to the well head and has a weight of approximately 3000 kg[17]. During the approval process in Germany staticcalculations have been made which confirm that the forces applied to the flange by the hydraulic cylinder are completely uncritical [20]. Therefore no additional foundations, which are necessary for the mechanical Pump Jack, are needed for the R7 and no additional measures have to be taken for the well head [1].

Ecoquip 9000 Series Hydraulic Pump Jack

As well as the Bosch Rexroth System R7 described above, the Ecoquip 9000 Hydraulic Pump Jack is a hydraulic drive system for a sucker rod pump. This means the down-hole pump stays the same as for a mechanical Pump Jack – only the surface system is changed.

Main Principle

Components

The system basically is composed of two components:

A hydraulic aggregate consisting of a master cylinder, a hydraulic pump, a motor and a control panel and the hydraulic slave cylinders, which are mounted on the wellhead. The basic configuration of this unit is shown in Figure 21.

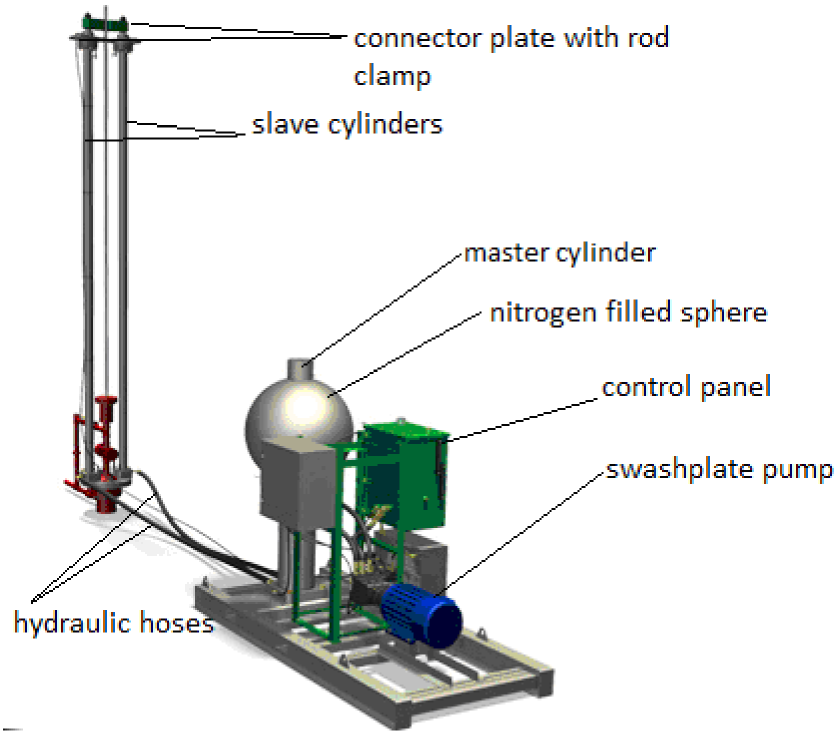


Figure 21:Hydraulic Pump Jack Components[21]

The hydraulic pump which drives the master cylinder and – on this way – the slave cylinders is an electrically controlled positive displacement swash plate-type pump.

The master cylinder is composed of a cylinder shell with a free floating master piston operating inside. Mid-point on the longitudinal axes of the cylinder, there is a sealing bulkhead installed, which restricts the free movement of the master piston (Figure 22). The master piston itself comes with an upper and lower piston head, which are held on opposite sides of the bulkhead. The bulkhead contains a bulkhead seal which – in connection with the connecting rod of the master piston – forms a fluid tight seal between the upper and lower part of the master cylinder[23].

On the upper side of the master cylinder a gas tight, nitrogen-filled, sphere is mounted in a way that the master cylinder is open to the sphere. As shown in Figure 22 these components form four chambers inside the master cylinder: Chamber A at the lower end of the lower master piston head, chamber B between the lower master piston head and the bulkhead, chamber C with the bulkhead as a lower boundary and the upper master piston head as upper boundary and the uppermost part of the cylinder and the sphere as chamber D. Chambers A, B and C are filled with a hydraulic fluid, while chamber D is filled with nitrogen. A thin layer of lubrication agent lies on the upper master piston head[23].

Two pipes or hoses are connected to two hydraulic ports inside the bulkhead and lead to the swash-plate pump.

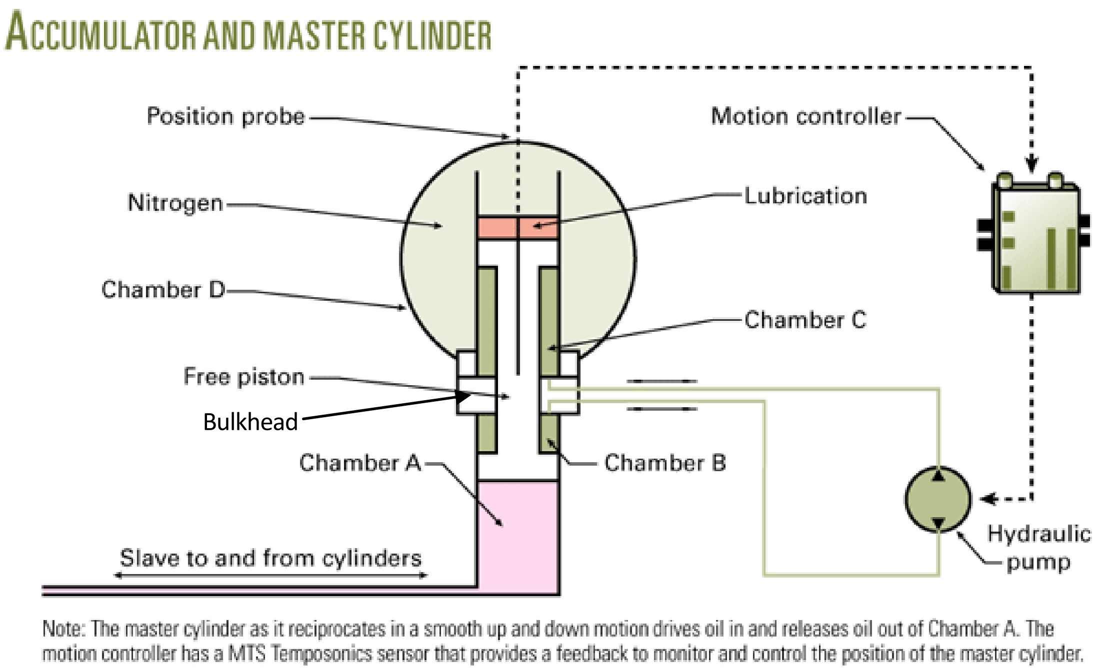


Figure 22:Accumulator and Master Cylinder[22]

Two hoses connect chamber A with the two slave cylinders. These slave cylinders are mounted parallel, one on either side of the well head, and are connected with cylinder tie members to hold the cylinders in a fixed distance to each other. Thesecross members are typically a fixed brace or connector plate in connection to a rod clamp which connects the polished rod with the hydraulic drive system[23],[24]. Also mounted on the top of the slave cylinders is a gooseneck assembly which provides the possibility to operate rod rotators[25].

Prime mover for the hydraulic pump jack can be an electric or gas motor[26].

At the uppermost part of the sphere a position measuring magnetic sensor system is installed, ending in the master piston.As shown in Figure 23 the sensor consists of a measuring head (43) and a magnetic field generator (44). The magnetic field generator is placed in the master piston's upper head. When the master piston moves up and down, a voltage is induced within the sensing element and sent to a control panel [23].

Another part of the system is the motion controller which receives the signal from the position sensor and controls the pump [27].

The control panel , with a power requirement of 10 to 30 V operates in a temperature range of -40 to +70°C. At the control panel a touch-screen is installed to adjust the system[28]. Pressure sensors for real-time dynamograms are optional[27].

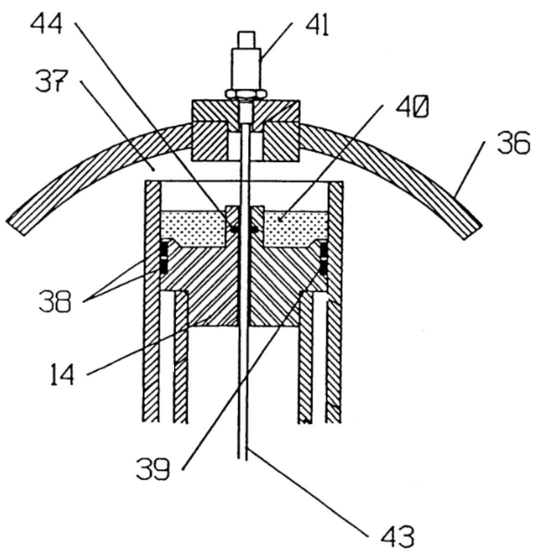


Figure 23:Scheme from inside the energy storage [23]

Working Principle

The two slave cylinders are driven by a hydraulic working fluid. When the master piston moves downwards, the fluid in chamber A is forced through the two hoses to the slave cylinders. The hydraulic fluid is entering the slave cylinder chambers, forcing the cylinders upwards. As the slave cylinder pistons are connected to the polished rod, the sucker rod string is drawn upwards.

The master piston's downward movement is achieved by hydraulic fluid which is drawn from chamber C through the hydraulic pump to chamber B, forcing (in connection with the gravity force) the master piston to move downwards (Figure 24)[23].

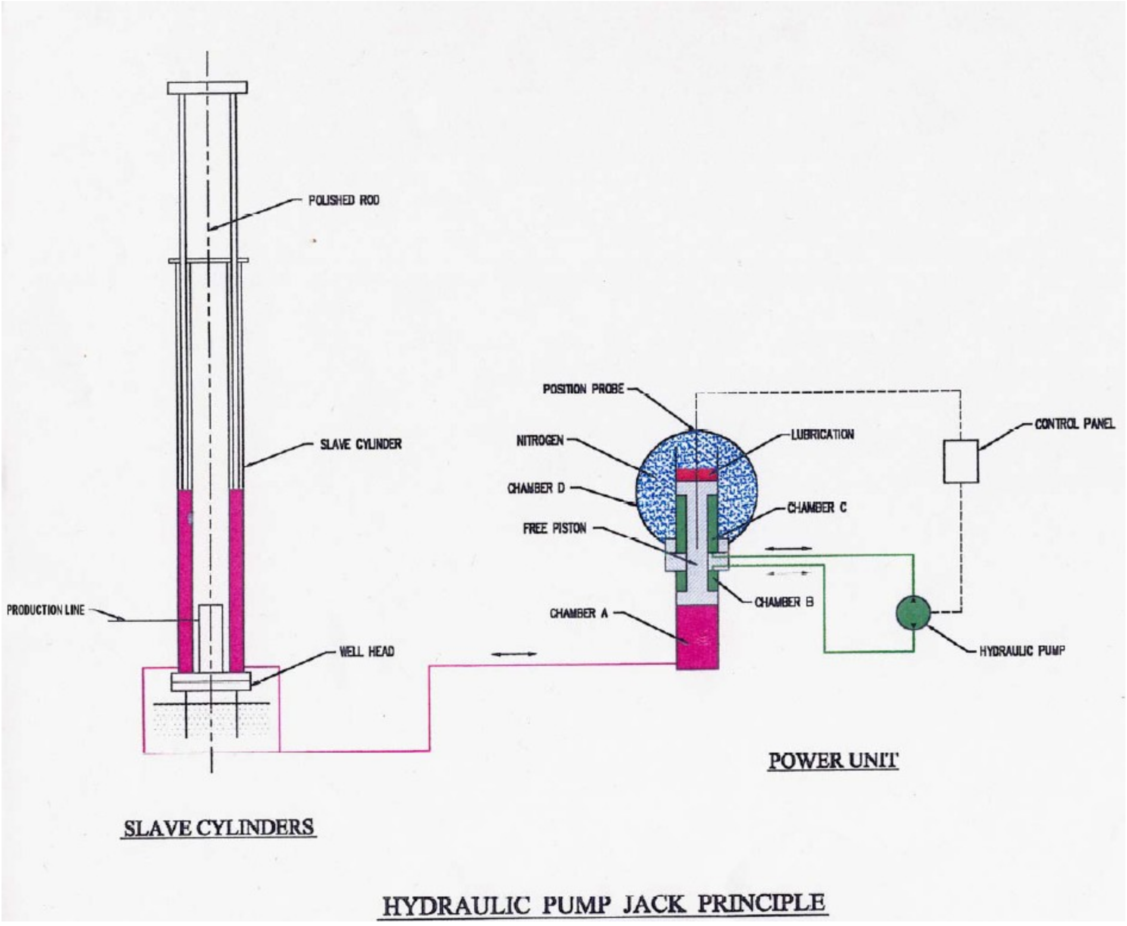


Figure 24:Hydraulic Pump Jack Principle[29]

The upward movement of the master piston is achieved by two main driving forces: The gravity force acts on the rod string (which is connected to the slave cylinders) and forces rod string and slave cylinders to a downwards movement.Hereby the hydraulic fluid is pressed back into chamber A and the hydraulic fluid from chamber B is pumped by the hydraulic pump into chamber C[23].

Now, as mentioned above, the potential energy, which is set free by the downwards movement of the rod string forms the major part of the whole energy requirement of any hydraulic pump jack system. In the Ecoquip 9000 Hydraulic Pump Jack system, the downward movement of the rod string assists the whole system in forcing the hydraulic working fluid back into chamber A. Thisassists the hydraulic pump to force the fluid out of chamber B into chamber C. During the upward movement of the master piston, the nitrogen in the upper, open part of the master cylinder, which is hydraulically open connected to the nitrogen-filled sphere, is pressurized. The closed system which is not connected to the environment, acts as energy storage for the potential energy which is set free by the downward movement of the rod string and this energy assists the pump used to force the master piston upwards; At the reverse action this energy assists the hydraulic pump in driving the master piston at its downwards movement. The other function of the nitrogen-filled sphere is to counter-weight the downwards movement of the sucker rod string, so that the rod string doesn't just “fall” down driven by its own weight, but is controlled and varied in speed [23].

The energy-storage sphere is pressurized with nitrogen while the system is operating[26]. The necessary pressure (max. 100 bar) is determined by the weight of the rod strong, and therefore partially dependent on the depth of the well. The spherical shape of the energy storage is chosen because the internal stresses can be more evenly distributed. Nitrogen as working gas is taken because it isinert and does no harm to the environment [23].

The hydraulic pump, as mentioned above, is a swash-plate type. When the pump swashes in one direction the hydraulic oil flows from chamber B into chamber C vice versa. The hydraulic pump is driven by a proportional servo valve which is controlled by an electro-hydraulic motion controller[27].

The gas pressure in the energy storage can vary in terms of temperature-dependency or small leakages a three-position pressure. To provide the possibility of adding or removing gas from the sphere a balancing shuttle valve is integrated in the system. It is connected to the hydraulic pump as well as to the energy storage. Three settings are possible: First to prevent a short-cut between the pump and the sphere, second to pump hydraulic oil from the pump into the sphere and third to provide the possibility to remove fluid from the sphere. To work in an effective way, the shuttle valve has to work automatically, it is operated in one direction by a spring valve, and by the pressure in the sphere in the other direction. If the sphere is within the pre-set pressure boundaries, the valve is held in closed position. If the pressure drops below a certain limit, the force applied by the spring will overcome the force applied by the inside pressure – the valve switches to the second position and fluid is pumped into the sphere, increasing the pressure again. If the pressure in the sphere is higher than pre-set, the force applied by the pressure will actuate the valve into the third position – fluid is drawn from the sphere into a fluid reservoir. The use of a pair of two-position valves is also possible. One valve is used to add fluid in case of under-pressure, the other onedrains fluid in case of over-pressure[23].

As in every hydraulic system leaksmay occur and even small leaks have a very high impact on the balance of the hydraulic pump jack, the Ecoquip 9000 Pump Jack uses an automatic fluid-adding system. A small, additional pump controls the working fluid volume. Basically during every stroke of the master piston, a small volume of fluid is added to the system. The small pump adds approximately ~0.012 ml per stroke. To prevent overfilling the system is equipped with an over-stroke valve. This valve's actuator is hydraulically connected to chamber A and to the slave cylinder rod. In case of overfilling, the reciprocating of the master piston will cause the sucker rod string to be lifted higher than pre-set. Then the valve will be opened and a small amount of fluid can be drawn from this chamber[23].

The efficiency will decreasein case of contamination of the system caused by e.g. abrasion at the cylinder wall. Therefore it is advisable to install a charge pump circuit, to clean the hydraulic oil and control its temperature. This circuit removes continuously a part of the oil while it is pumped from chamber B to chamber C. The oil is extracted through an additional valve from the chamber with the lower pressure. Now the fluid passes a number of valves, e.g. one thermostatically controlled one, which allows to lead the oil to a cooling unit if a pre-set temperature is exceeded. After the fluid is cooled, if necessary, it is led through a filter that removes possible contaminants and pumped back into the hydraulic cycle again. In a similar way, the hydraulic fluid which is pumped from chamber A to the slave cylinders and back again is cleaned[23].

As mentioned above, a position measuring sensor is installed at the nitrogen-sphere to monitor the position of the master piston (Figure 23). Knowing the master piston’s position means also to “know” the rod string’s position inside the well as well as up- and downstroke velocity. With this information the operation of the hydraulic pump can be set in a way that can avoid to abrupt change of directions of the rod string. The exact real-time measuring of the master piston’s position provides full flexibility in terms of stroke length[23].

Installation

According to manufacturer installation is completed and the system ready for operation in 2-3 [hrs] if all surrounding equipment as fuel supply, wellhead, flow lines, tanks or pipelines is prepared [25].

Monitoring and Diagnosis

As mentioned above, the controller receives a signal from the position measuring sensor and therefore controls the upstroke and downstroke velocity independent of each other. The slave cylinders can be rapidly stopped or started, stroke length can be controlled and easily varied[23].

It is also possible to add hydraulic pressure sensors to the system, which providesreal-time dynamograms for full well control and monitoring. In this case it is possible to changeparameters like pump speed, stroke length automatically [27].

Other controlled parmeters are temperatures of the pump, the speed of cooling fans, hydraulic oil and the system alarms[23].

Possible Configurations

According to the manufacturer the Ecoquip 9000 Hydraulic Pump Jack covers the whole production range of a conventional mechanical unit.

It is available in two sizes:

Model	9000-5	9000-6	9000-9
Max. polished rod load lbs	20,000	32,000	64,000
Max. polished rod load kg	9,072	14,515	29,030
Max. stroke length in	100	144	240
Max. stroke length cm	254	366	610
Max. stroke speed [spm]		6-7	3-4

Table 7: Overview over the different types of Ecoquip 9000 Series[26]

The type 9000-5 is declared as “coming soon” by the manufacturer.

Most of the pumps are installed at 1,000-7,000 ft depth, average well depth is around 4,000 ft. A 80-100 [HP] hydraulic pump is normally used [27].

The values shown below are given for the 9000-6 unit.

Specifications		
Slave cylinders	Height	At downstroke: 6.1 m (20ft) Extended: + 3.66 m (12 ft) Absolute: 9.76 m (32 ft)
	Weight	953 kg (2,100 lbs)
Skid (containing power unit and master cylinder)	Weight	2,722 kg (6,000 lbs)
	Height	2.3 m (7,5 ft) at top of master cylinder
	Length	3.1 m (10 ft)
	Width	1.22 m (4 ft)
Prime mover	GMV6 Or V8 motors Electric Motor	Fuelled by propane or clean wellhead fuel 10 HP
Operating values	Max. stroke frequency	7 [spm]

Table 8: Specifications of the Ecoquip 9000-6 [25][26]

<u>For this type of pump the following capacities are typical[27]:</u>

A sucker rod pump with 2.75 in diameter: With 6 spm a 366 cm (144 in) fluid column can be lifted, at a pump efficiency of around 85%, the pump is able to produce 103 m³/d (648 bbl/d).

A sucker rod pump with 1.5 in diameter with same variables is able to lift about 30.7 m³ (193 bbl/d).

Otherwise another reference lists a load of rod and payload of produced fluid weighs 12,247-15,876 kg (27,000-35,000 lbs), which would be more than the max. polished rod load allows[27].

For the same type it is also noted that the master-rod/slave-rod-ratio in lifting height (inch) is 1:6.

Health, Safety and Environment

Similar to the Bosch Rexroth R7, Ecoquip 9000 Hydraulic Pump Jack has no rotating parts at the well site which could form HSE hazards for unauthorized persons.However the portion of free accessible moving parts is significantly higher than for R7, because the slave cylinders and the polished rod move upwards and downwards.

There is no necessity of any proximity or open limit switches at the slave cylinder assembly, due to the fact, that all settings of the sucker rod can be operated from the power unit [25].

Because of the high pressure hydraulic fluid the same HSE considerationsare valid as for the R7.Three high pressurized zones exist in the system: the nitrogen-filled sphere, the master cylinder and the connection lines between the master cylinder and the slave cylinders which form a HSE risk.

Economics

Item			**Costs [€]**
CAPEX			135,000
Additional Installation Costs	Electrical Technician, additional personnel, hydraulic oil		
OPEX			
Changing of Hydraulic Filters	6 times a year, 5 [min]	1 person	
Checking the balancing of the unit	At regular intervals, 20 [min]	1 person	
Hydraulic Oil	After some years		
Non-productive time	All maintenance	Per year	
Electrical consumption			

Table 9: Economic Performance [25]

Advantages and Disadvantages

Disadvantages

Economics

In comparison to a conventional beam pump the CAPEX for the whole system (including motor, control panel, slave cylinders and the master skid) is quite high. Estimated costs are € 104 000 ($ 135,000)[25].

The main disadvantage of the Hydraulic Pump Jack is the change of the master cylinder sealing. The slave cylinder sealing has a mean time between failures (MTBF) of max. 6 and average 3 years, and can be changed on site within a few hours. The master cylinder sealing doesn't even reach 3 years and then the whole skid must be taken to the shop for resealing [25]. This means a significant production loss unless a stand-by system can be installed. Systems which use a nitrogen-filled accumulator sphere to store the potential energy at the downstroke, showed to be very maintenance and service intensive[1]. This corresponds to the information given by Ecoquip, who recommends a 3 month service interval for filter change-out and motor service[25].

Other systems, also using a nitrogen-filled sphere as the pressure accumulator show a significantly decrease of efficiency proportional to the number of up- and downstroke cycles. After 50.000 cycles the cycle efficiency decreased. If calculating with 4 spm and continuous production, this efficiency drop would start 9 days after starting the system[1].

Nitrogen-filled Sphere as Pressure Accumulator

The Bosch Rexroth R6, which used the same principle as the Ecoquip's 9000 series Hydraulic Pump Jack, was very temperature-dependent. Strong environmental temperature changes caused significantly pressure losses in the Nitrogen sphere [1]. According to the Patent, Ecoquip tries to compensate these pressure losses by adding fluid into the accumulator or removing it [23]. Another possibility is maintenance: A workers has to add Nitrogen through a port at the sphere after some time to held the necessary pressure level[25].

Ecoquip also reports that regular re-filling of the nitrogen-sphere is necessary every 6-8 weeks at R6.

Advantages

Visibility and Footprint

The unit provides a very small footprint. The hydraulic aggregate is low in profile and easily overseen. The overhead clearance of the slave cylinders –if extended – is approximately 10 m[25]. The slave cylinder/polished rod combination is slender and has a much smaller visual impact than a mechanical Pump Jack.

No Foundations needed

The unit is a lot lighter than a mechanical sucker rod drive. It weighs only about 953 kg (2,100 lbs), the power unit additionally 2,722 kg (6,000 lbs)[25]. Therefore it does not need foundations, but a leveled ground is recommended for the power unit. This can be achieved either by gravelling or by installingthe unit on two 5 cm x 20 cm x 2 m (2 in x 8 in x 6 ft) planks that keep the frame in place. The slave cylinders are mounted directly on the well head[26].

Ease of installation

Normally the units are transported by small pick-up trucks. The whole system is very easily installed and de-installed. A crew of two is able to to set it up and start it in 2-3 hours. Break-down is even quicker: two people can de-install the system in around 2 hours. According to the manufacturer the installation costs are quite low compared to other systems [25].

Rod Rotators

It is possible to add rod rotators to the system if the well trajectory requires it, making the system attractive also for deviated wells, where tubing and rod or rod protector wear may be a problem. According to the manufacturer up to 95% of the wells driven by the 9000 series Hydraulic Pump Jack are equipped with a rod rotator[25].

Real-Time Monitoring

Rod loads can be monitored real-time directly from the hydraulic pressure and sent to the control panel. Stroke speeds and accelerations, stroke length, etc. can be set easily from the panel as well. Therefore full flexibility to react on changing production conditions is given. The control system can be equipped with"remote monitoring and control packages". The aim will be full remote controllability of the single units [27].

Load Protection

The accumulator support for the slave cylinder motion softens the changes in up- and downwards motion and therefore prevents abrupt and fast loadings of the rod string as well as the surface equipment.

HRPI Subsurface Hydraulic Rod Pump

Compared to the systems described above the HRPI Subsurface Hydraulic Rod Pump differs significantly.

Main Principle

Components

Basic element of the system is a subsurface hydraulic cylinder, which is installed in the tubing string and remains submerged in the production fluids while operating. It is mounted inside the well head therefore modifications at the well head are required. As shown in Figure 25, the well head includes a casing gas outlet, a double-studded landing flange, a cylinder flange, the hydraulic hoses and the flow line.

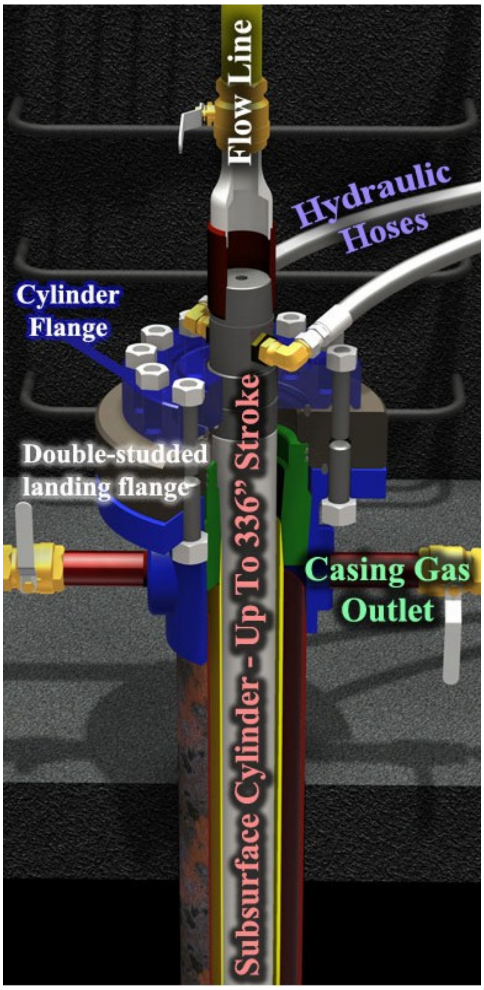


Figure 25:Wellhead Configuration for the Subsurface Hydraulic Cylinder [31]

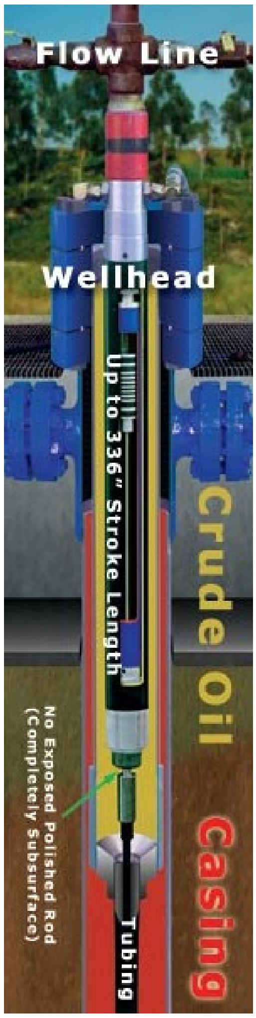


Figure 26:Internal Installation [30]

This cylinder includes the cylinder piston which is directly attached to the polished rod. To prevent a contamination of the hydraulic fluid with wellbore fluids or solids, a double-sided (back-to-back) high pressure seal is installed at the lower end of the cylinder[33]. The sealing section provides internal scrapers and bushings as well as packing.

The second part of the system is a Power Unit, which exists (if non-counterbalanced) in single or dual well design, or in a nitrogen-counterbalanced single well version.

The non-counterbalanced power units consist of an atmospheric oil reservoir, a hydraulic pump, a three-position, four-way directional control valve, an adjustable throttle valve (for controlling the back flow at the downstroke) and a check valve to bypass the throttle valve for upstroke.

Also a cooling system and a return flow filtration are components of the system.

The nitrogen-counterbalanced power units more or less comprise the same elements as the non-counterbalanced units, but include a hydraulic motor that is close-coupled with the pump and consumes nitrogen-pressurized oil from an accumulator. An additional hydraulic pump is close-coupled to the main pump and the motor. In this system as in the non-counterbalanced one, a cooling device and filtration is included. Also parts of the system are automatic shut-off valves on the accumulator and cylinder and as well as automatic system bleed-down valves.

The accumulator is designed with ample storage capacities and a flexible manifold circuitry.

The main power-supply for the non-counterbalanced as well as the nitrogen-counterbalanced units is an electric motor, for the counterbalanced unit gas or diesel engines are also possible.

For safety and monitoring reasons, the system is equipped with several sensors, e.g. pressure sensors, a flow sensor, temperature sensors, etc.

The Units themselves provides a PLC (Programmable Logic Controller) for monitoring, which can be equipped with an operator interface at the power unit for monitoring and setting of variables.

Working Principle

The basic principle is the following: The main pump draws hydraulic oil from a reservoir (at atmospheric pressure) and pressurizes it up to working pressure. The flow is directed by the control valve through the hydraulic hose to the cylinder, where the piston is lifted up to a pre-set point. The upstroke velocity is adjusted by the hydraulic pump displacement. Once this point is reached, the control valve re-directs the flow and the hydraulic oil is drawn back into the reservoir. The throttle valve controls (and adjusts) the downstroke velocity. During the upstroke the flow is bypassed around the throttle valve by the check valve.

Other thanin the two systems described above, the change from up- to downstroke and back again does not work over a position measuring sensor, but over the displacement volume of the hydraulic pump and the volume of the cylinder. If a pre-set volume of oil is pumped into the cylinder, the system changes from up- to downstroke. Additionally pressure and flow sensors monitor the pumping situation.

The system provides a very advanced computer control and monitoring. Pressure sensors send information to draw the dynamograms real-time.

Non-counterbalanced Single and Dual Well Power Units

Basically these units simply convert electrical energy into linear motion. The units are the same ones for single and dual well application, so the single well units are dual well units operating as single well ones.

The dual well unit alternately strokes each well, one well is in upstroke while the other well strokes down. It is possible to vary the strokes per minute independently, using “ratio-cycling”.

For the dual well power unit a gas or diesel engine as prime mover is not possible, due to heavy cyclic loading fluctuations caused by a powered upstroke.

Nitrogen-balanced Well Power Units

The basic working principle for these units is the same as described above. Additionally, a hydraulic motor and a small displacement pump are coupled to the main pump. A nitrogen pressure-accumulator exists, which pressurizes hydraulic oil to assist the pump. Therefore a pump with lower HP requirement is necessary to lift the same polished rod load.

During the downstroke the directional control valve directs the pump flow not directly to the reservoir, but to the accumulator. The motor is driven by the back-flowing oil and assists the main pump to charge up the accumulator again during the downstroke. The back-flow from the cylinder is controlled by the pressure-load on the main pump through to the re-charging of the accumulator and the electric motor’s resistance against overrunning.

The additional pump pre-charges the accumulator with oil while setting the pump into operation. During the normal operation it adds oil to prevent a loss of pressure due to oil leakage and consumption (by the motor).

The nitrogen-accumulator is designed with ample storage capacities and a flexible manifold circuitry to allow a manual or automated setting of the system pressures.

Two types of nitrogen-balanced units are available: One for fixed and one for variable displacement. The variable displacement type provides the ability to adjust up – and downstroke velocity independent of each other.

Gas or diesel engines as prime movers are possible, the load fluctuations due to the balanced situation is stable.

According to the manufacturer pressures, temperature, amperage and oil levels are monitored.

Long Stroke Pumping

Long Stroke pumping differs from conventional rod pumping by the stroke length, stroke frequency and surface stroke length to rod stretch ratio. To stay with the definition of the manufacturer, long stroke pumping means stroke pumping with stroke lengths longer than 610 cm (240 in)[33].Basically, in non-corrosive situations, the fatigue resistance of sucker rod material is shown byFigure 27. Hereby the fatigue resistance decreases rapidly within the first million of cycles and then reaches a certain stable level. Theoretically this line is not declining, therefore the rod material should never fail if the allowed stresses are not exceeded[38].

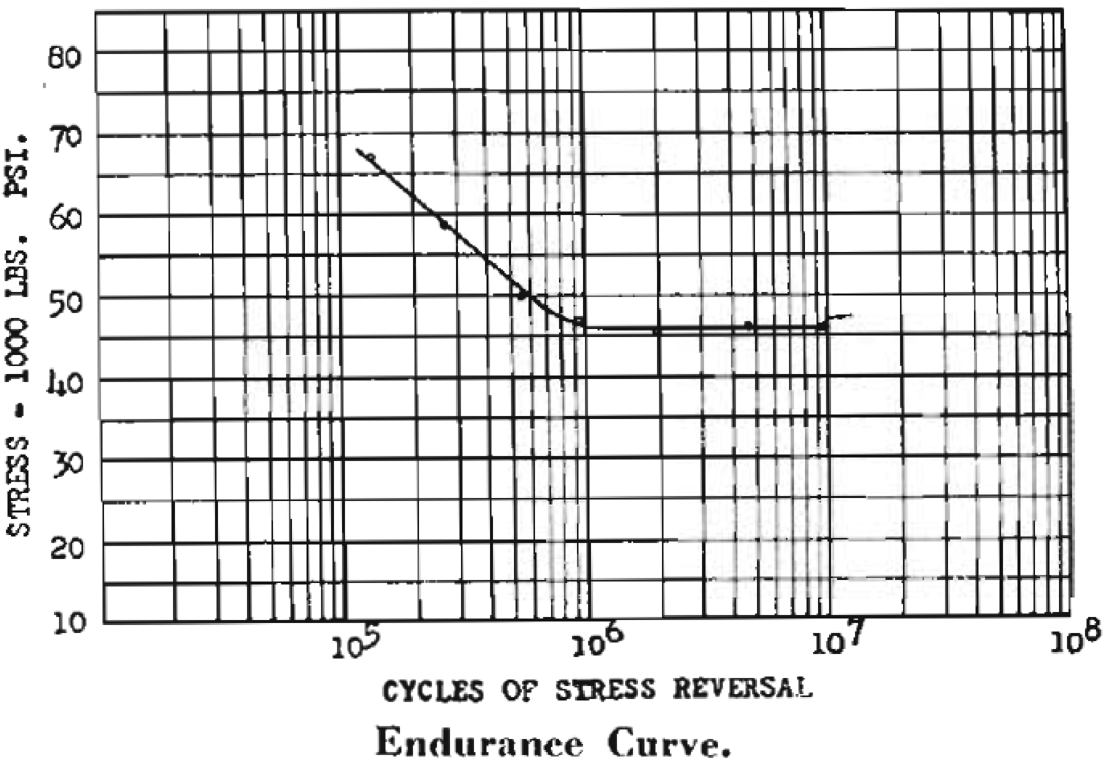


Figure 27:Endurance curve[38]

As a matter of fact this would only be true if operating in an absolute non-corrosive environment. Wellbore fluids often contain saline water, CO_2 and H_2S . Dale and Johnson (1940) conducted several studies in order to establish fatigue resistance curves for sucker rod material in corroding environments.

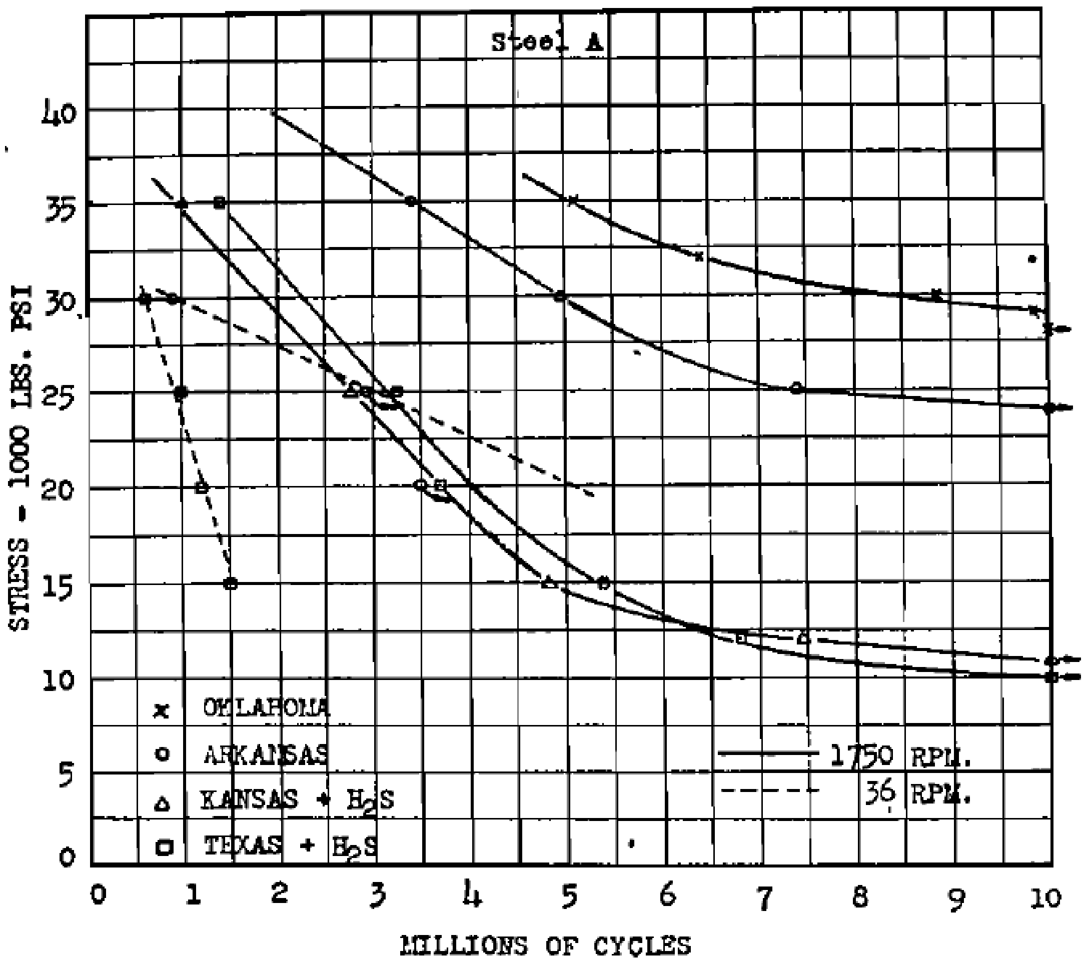


Figure 28: Endurance curves in different environments [38]

Figure 28 shows the stress vs. cylces-curve for a steel in different environments, two of them containing hydrogen sulphide and with different velocities. The curves have been established in the laboratory – numbers of 1750 and 36 rpm cannot be reached in the field. But the graph shows two important facts[38]:

Firstly the curve is not paralell in reality is not parallel to the x-Axes, so the maximum allowed stresses are declining with increasing number of cycles. In practice this means that even in slightly corrosive environment every rod will fail after some million of cycles[38].

Figure 28 also shows curves for lower velocity. If the number of cycles can be reduced e.g. by slow or long-stroke pumping the occurrence of fatigue failure can be retarded due to the fact that the curve is not related to operation time, but to millions of cycles.

Characteristically long-stroke pumps operate with fewer strokes per minute, as every stroke has to overcome a longer way, which takes more time.Bommer and Shrauner (2006) formulate *"The faster a unit pumps, the larger the number of cycles, and the sooner the rods reach a fatigue limit" [39].* Which means that with fewer cycles it takes more time to reach the fatigue limit.

Sucker rod pumps working with higher stroke lengths basically show higher volumetric pump efficiencies due to the surface stroke length to rod stretch ratio. At the start of the upstroke, the rod string stretches before the bottomhole plunger begins to lift fluid. Therefore a part of the stroke length which is measured at the surface is lost. During the downstroke the rod is compressed again. If a sucker rod pump with 305 cm (120 in) surface stroke length has a rod string stretch of 30 cm (12 in), 10% of the upstroke is lost. For the same rod string stretch and plunger load this loss would be the half if the surface rod length doubles: If a rod string stretches 30 cm (12 in) at a stroke length of 610 cm (240 in), the loss is eliminated at 5 %. These losses can also be seen as efficiency losses.

The time which is spent by stretching the rod is lower at long stroke pumps: As mentioned above, long stroke pumping units show a lower frequency because it takes more time to complete one single stroke. If instead of 6 spmonly 4 spm are done, the 30 cm (12 in) stretching is done 4 times instead of 6. This leaves a longer gross lifting time than shorter stroke pumps can have. Basically up to 5% more production can be achieved at same “inches per minute” travelling speed[33].

Every up- and downstroke causes acceleration and deceleration of the rod string. At the beginning of the upstroke the rod string is accelerated very quickly. This may cause high peak stresses, in some cases higher than ideal. The acceleration at the beginning of the downstroke causes the upper part of the string to “fall” faster than the middle or lower rod string. Due to some other influences, e.g. as fluid resistance against the plunger (fluid viscosity, gas lock), rod friction and hydraulic resistance of fluid passing around rod couplings and rod guides, compression may occur.

The rod design and therefore the calculation of the maximum allowable loads on the rod is normally done by the API method basing on the Modified Goodman Diagram.

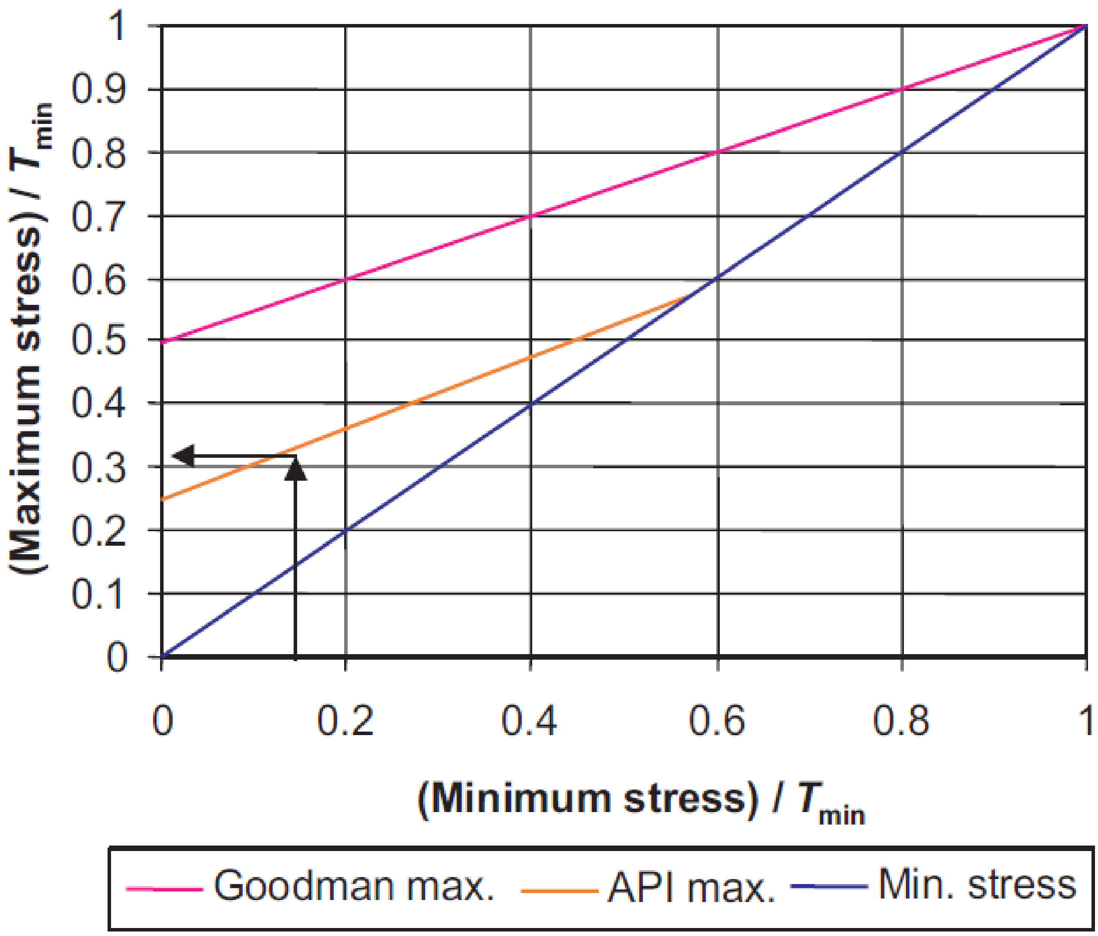


Figure 29:Modified Goodman Diagram [39]

The maximum line is hereby described by

$$\frac{\sigma_{max}}{T_{min}} = \frac{1}{4} + 0.5625\frac{\sigma_{min}}{T_{min}}$$

So stress is described as a fraction of the minimum tensile strength of a rod. The intercept of the of the maximum stress line at zero minimum stress is defined as the fatigue strength of the rod. This is related to the required number of cycles. For the API maximum, the fatigue strength is one quarter of the minimum tensile strength. The calculated number of cycles is around 10 million. A rod can also operate at more cycles without fatigue if the required fatigue strength is a smaller fraction of the tensile strength of the rod[39].

As shown in Figure 29 the predicted time to fatigue failure is calculated for tensional load. The ideal case would be maximum and minimum load in tension. The life of the rod string decreases significantly if the minimum load is in compression [39].

The ideal case is to have one stress fluctuation per cycle within the tensile load region. The above mentioned abnormal loads appear as measureable dynamic sine-shaped waves on the dynamometer card (Figure 31). It is often referred to as “rubber band”-effect, due to the fact that it is related to the elasticity of the rod string. The rod hereby is thought as a weight hanging on a rubber band. If the rod is loaded cyclically with abnormal loads, rod string fatigue will occur [33].

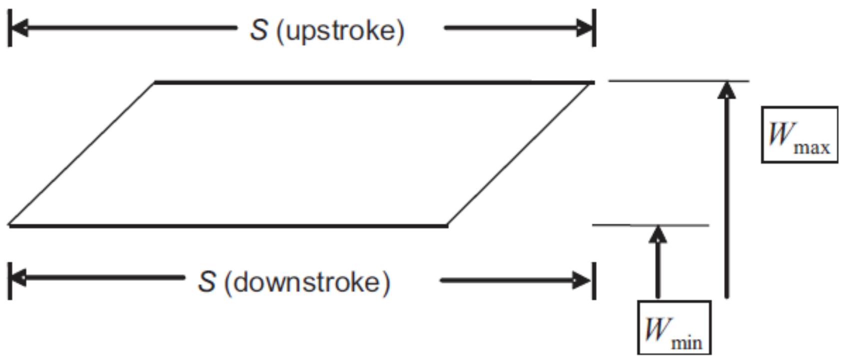


Figure 30: Ideal surface dynamometer card [39]

Figure 30shows an ideal surface dynamometer card without any load fluctuations or compression. The rod stretch is represented by the parallelogram shape.

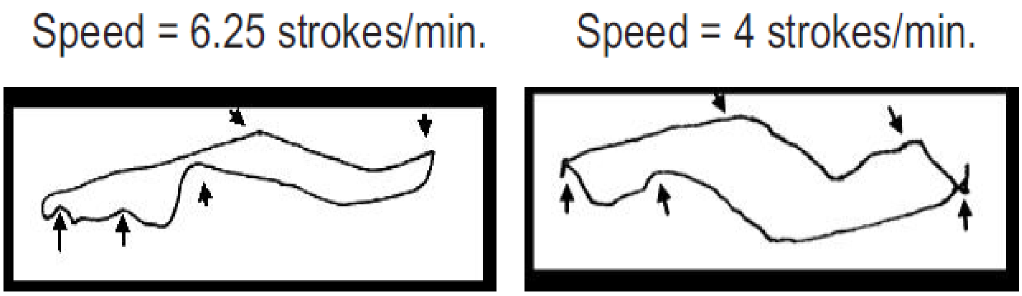


Figure 31: Real dynamograms [39]

In this connection “abnormal loads” are: varying pump loads due to fluid level fluctuations, fluid viscosity changes, well bore deviations, sudden speed changes as e.g. sticking pumps, temperature changes, presence of corrosives, fluctuating presensce of gas, tubing movement, etc [33].

Long stroke pumping provides longer, smoother strokes due to linear travel speeds. As shown in Figure 31 this significantly reduces the dynamic wave-form loads because the string is accelerated to a slower fixed rate and it is holding this constant rate for the majority of the stroke. The arrows indicate the load fluctuations [33].

Rod compression has another aspect concerning the life expectancy of the rod string: Buckling. In many cases compression causes the rod to buckle inside the tubing, hereby creating unwanted contact between tubing and rod. The result is excessive rod and tubing wear and failure. One possibility to overcome buckling is to avoid compression as explained above. If this is not possible, long stroke units show another effect which increases rod and tubing life: The pattern of wear is distributed over larger areas/longer distances. The tubing/rod contact normally occurs at the rod coupling which has normally a larger OD than the string itself. Therefore the contact loads are concentrated on a small area, which travels up and down exactly the distance of one stroke length. If this stroke length is longer, the wear pattern is distributed over a larger area. This enhancement helps to extend the life of the tubing [33].

Maintenance Intervals and Workover

Job	Regularity	Personnel required	Time [h]
Hydraulic filter change	Every 3 months	1	
Visually inspection of the Unit	Every month	1	

Table 10: Maintenance Schedule [36]

As shown in Table 10 the only required maintenance is a change of hydraulic filters every three months. The visual inspection once a month is basically the same as required for conventional pump jacks.

For the workover no additional equipment or personnel is necessary. Nevertheless the personnel has to be trained for the installation and de-installation of the hydraulic cylinder. The cylinder has to be removed for every workover [36]

Installation

At first the rod string should be installed. Then the hydraulic cylinder has to be installed. Next step is to set the surface unit by a fork lift, and then to connect the power lines. At last the hydraulic hoses or pipes have to be connected[36].

Installation Schedule

Job	Time
Installation of hydraulic cylinder	1 [h]
Hydraulic steel line connection and electrical power lines connection	2.5 [h]
Placement of Surface Unit	0.5 [h]

Table 11: Installation Schedule of the HRPI Subsurface Hydraulic Rod Pump [36]

Monitoring and Diagnostics

The already mentioned PLC system provides the possibility to adjust stroke length and velocity, safety settings, dynamometer cards, automatic pump-off control, data storage, remote telemetry etc.

To provide a control for the cylinder stroke length and velocity the PLCcalculates SPM timing and stroke ratios (in case of dual completions) and sends information to the control valves, meaning it delivers the timing to the directional valve which itself controls the flow direction. The user just has to set the desired stroke length (in percent of a full stroke or inch), strokes per minute, and perhaps velocity difference for upstroke/downstroke. It is also possible to select the upper and lower portion of the available stroke, and therefore stroke position.

Using solid-state electronic pressure transmitters the system is also able to adjust user selected stroke timer setting and therefore react on changing well conditions and hydraulic system efficiencies[33].

As mentioned above the system is able to produce real-time dynamograms by monitoring the hydraulic pressure and they are streamed as they are collected [34].

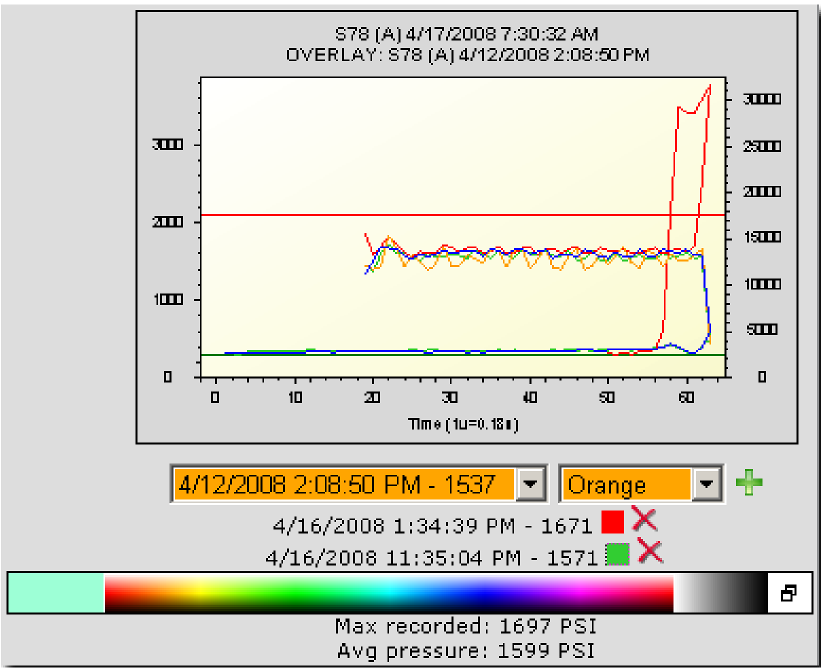


Figure 32:Overlayed dynograms from http://pumpreports.com[34]

The PLC provides an automatic pump-off controller, which compares the pressures/loads from the dynamograms to user pre-set data and shuts down when these values are reached.

The continuous hydraulic pressure is also used for a safety shut-down system in case of a malfunction of the directional hydraulic system. It is a two-stage safety procedure: During the upstroke first the stroke can be interrupted and then the system can be shut down totally[33].

The system provides the possibility of remotely adjusting the stroke velocity. Therefore it is possible to react very flexible on changing production parameters [34].

To achieve full flexibility and remote control the monitoring and analysis works web based and is provided by http://pumpreports.com. Therefore it is possible to access all available data from any standard web browser.

Some of the features of http://pumpreports.com are a complete well history including well document management, workover history, failure history etc., trend analysis graphs including fluid level history, production tests and surface equipment data, 3-D well bore diagrams including the possibility to overlay well data on a single 3-D interactive graph, current fluid levels and historical failure points..

http://pumpreports.com provides the possibility of access from every internet connection.

If the system doesn't work any more in the pre-set safety ranges, http://pumpreports.com will email and text message alerts[35].

Alerts

Location	Unit	Well	Subject/Message	Count	Sent
[illegible]	SANSI 5-3		DOWN-HI TEMP	105	
[illegible]	SANSI 5-3		HIGH OIL TEMP	72	
[illegible]	MOD-11	WP-13	Short Stroking	215	
[illegible]	UNIT #10	P-67	Short Stroking	1	
[illegible]	UNIT #21	S-65	Short Stroking	62	

Figure 33:Alerting table[34]

Possible Configurations

Hydraulic Cylinder

Cylinder Size (Bore x Stroke)	Max PPRL (@ 3000 psig)	Extended Length	Collapsed Length	Outside Diameter (Subsurface)	Minimum Casing Size at surface (Subsurface Cylinder)	Subsurface Available
2.5" x 240"	12,363	527" (44')	287" (24')	3.75"	5-1/2" (all weights)	Yes
3.0" x 240"	18,840	527" (44')	287" (24')	4.75"	7" (all weights)	Yes
3.5" x 240"	25,169	527" (44')	287" (24')	5.50"	8-5/8" (all weights)	Yes
3.5" x 288"	25,169	623" (52')	335" (28')	5.50"	8-5/8" (all weights)	Yes
3.5" x 336"	25,169	719" (60')	383" (32')	5.50"	8-5/8" (all weights)	-
4.0" x 240"	34,000	527" (44')	287" (24')	5.75"	8-5/8" (all weights)	Yes
4.0" x 288"	34,000	623" (52')	335" (28')	5.75"	8-5/8" (all weights)	Yes
4.0" x 336"	34,000	719" (60')	383" (32')	5.75"	8-5/8" (all weights)	-
4.5" x 240"	42,390	527" (44')	287" (24')	6.25"	9" (all weights)	Yes
4.5" x 288"	42,390	623" (52')	335" (28')	6.25"	9" (all weights)	-
4.5" x 336"	42,390	719" (60')	383" (32')	6.25"	9" (all weights)	Yes
5.0 x 336"	53,376	719" (60')	383" (32')	-	-	-

Table 12: Hydraulic Cylinder Specifications [31]

Table 12shows the specifications and casing size requirements of the subsurface hydraulic cylinders. The cylinders come with up to 19,228 kg (42,390 lbs) of Peak Polished Rod Load capacity and stroke lengths up to 854 cm (336 in). Due to the fact that the hydraulic cylinder is installed in the casing, a stuffing box at the well head is not required [31].

The unit weighs around 1,134 kg (2,500 lbs)[31].

Surface Unit

As mentioned above, the HRP Power Units, if choosing the non-counterbalanced type, are capable of single and dual well operation. The power supply for the HRP Hydraulic Power Unit can be either 480/460 VAC three-phase electrical power or a NEMA B[3]10 to 250 HPelectric motor.

[3]NEMA has established four different designs - A, B, C and D - for electrical induction motors:
NEMA B: maximum 5% slip, low starting current, high locked rotor torque, normal breakdown torque; suited for a broad variety of applications, normal starting torque - common in HVAC application with fans, blowers and pumps[37]

The hydraulic pump is available as a hydraulic vane pump with 3500 psi pump pressure rating and a 5-108 GPM pump displacement [32].

The average depth of the installed systems is around 2590 m, with a water cut of around 80% [36].

Economics

Item		Costs [€]	Costs [$]
CAPEX			
Single Well Application		42,070	55,000
Dual Well Application		Additional 13,000	Additional 17,000
Sound Enclosure		7650	10,000
OPEX per day (w/o electrical consumption)		16	20

Table 13: CAPEX and OPEX for the HRPI Subsurface Rod Pump [36]

Advantages and Disadvantages

Disadvantages

Energy Efficiency

When running as a single well unit, the system will consume more energy than a beam pump [36].

Noise

According to the manufacturer the system is designed to stay below 60 dB of noise, but it has to be noted, that hydraulic sucker rod pump drives are normally louder than conventional (the pumping unit is loud, not the cylinder). Additional noise protection in residential areas is necessary and has already been realised.

Figure 34:Soundproof unit[40]

Deviated Wells

It is possible to use the HRPI Subsurface Hydraulic Cylinders in deviated wells, but as the main force which draws the sucker rod downwards again is the gravity force, the degree of deviation is limited and horizontal well applications are not possible. There are wells where the system is used with around 20°/100ft dogleg severity, but normally max. 10°/100ft deviation is the max. possible value [36].

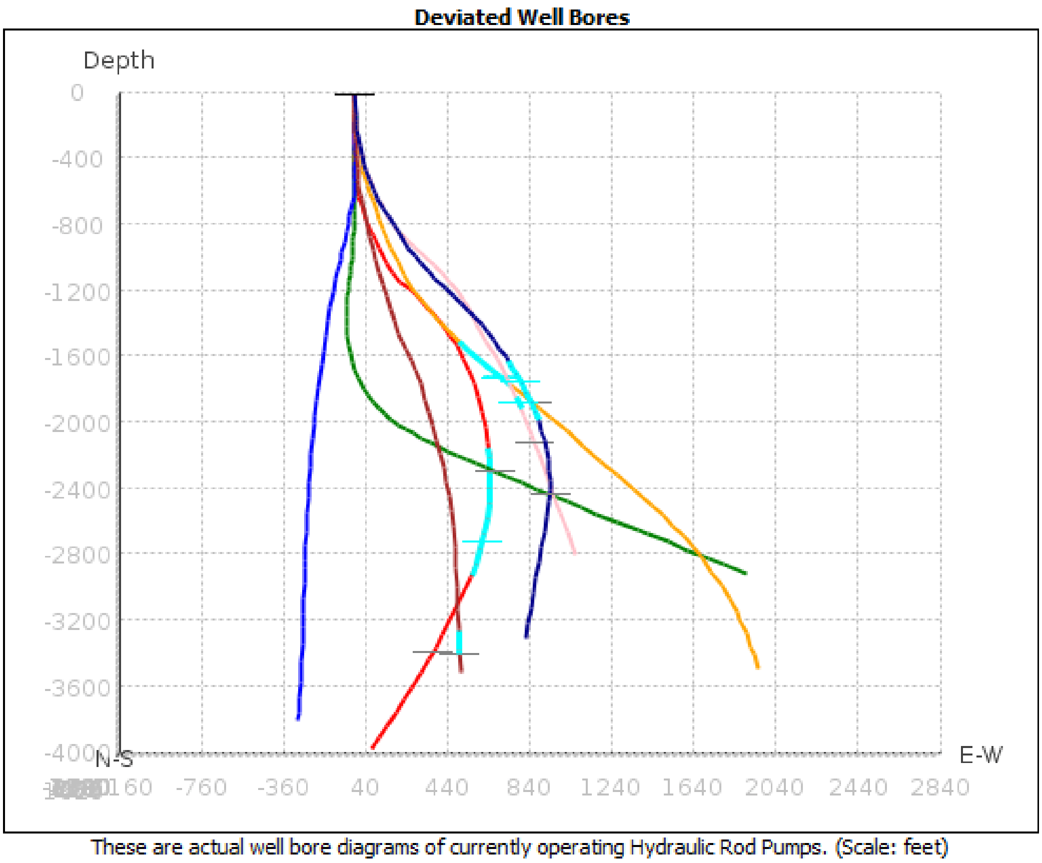


Figure 35:Wellbore profiles[41]

Figure 35 shows the wellbore profiles of some deviated wells where this system is used. From this graph it can be seen that the wellbore profile should be a S-Profile with a preferably vertical well bottom.

Maintenance

According to the manufacturer the surface equipment requires quarterly maintenance, including filter changes and inspection of hoses and seals.

Advantages

Small Footprint

The whole system has a small footprint. The hydraulic cylinder is submerged into the well itself and the power unit is quite small compared to a mechanical sucker rod drive. In connection to the possibility to use the dual well power unit and to separate the units from the wellhead (around 150 m (500 ft) of length are possible) the HRPI system can be used on- and offshore for densly populated drill sites. The picture below showssuch a situation [41].

These are actual wellheads for an urban drill site. Most of the wells in this picture are Hydraulic Rod Pumps.

Figure 36: Crowded well cellar[42]

The visibility profile of the subsurface cylinders and the small power unit is very low, which makes it possible to use it in residential areas. One of the systems is used on a golf course in Beverly Hills[43].

Dual Well installation

The possibility to use one power unit for a dual well installation provides energy savings in comparison with two beam pumps. Every well can be spaced max. 150m (500 ft) from the power unit, therefore it is possible to power two wells with a distance of max. 300 m (1000 ft). The power consumption is split between those two wells and the efficiency increases [36].

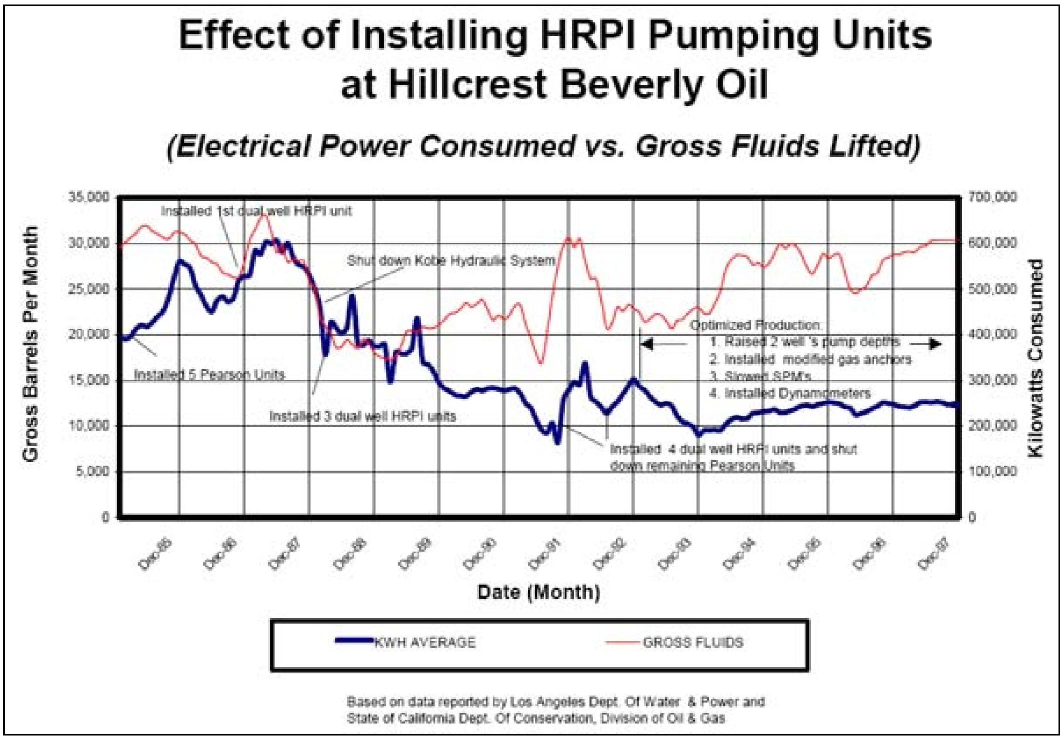


Figure 37:Energy savings in correlation to production increase for dual well powering[44]

Tubing Rotator

Optionally the system comes with a subsurface tubing rotator and/or a rod rotator. Therefore in moderately deviated wells the application is possible without excessive wear.

Figure 38:Tubing Rotator [41]

Real-Time Monitoring and Remote Control

The very advanced, internet-supplied remote control system for the Subsurface Hydraulic Rod Pump is definitely a big advantage of this system. It allows a very flexible reaction on changing production situations. This allows on the one hand a very effective and quick production which is not bound on the slow downstroke movements and can (in comparison to conventional mechanical units) shorten the cycle-time efficiently.

On the other hand, in case of low inflow, it eliminates the necessity for time-runners. This may - especially in wells with a high solid production - be an advantage as the settling sand and solids can block the down-hole valves of the pump and cause sticking when starting them again.

Reduced Bottomhole Equipment Wear

As explained above long stroke pumps show less strokes per minute. Less strokes per minute means also less cycling for the downhole-pump valves. The standing and travelling valves are designed for metal-to-metal impact every time the valve closes. Due to this working principle failures depending on cyclic wear increase with an increasing number of cycles. On the contrary: reducing the number of cycles, e.g. by 50% per minute, the valve life should theoretically be doubled by using the long stroke unit [33].

Reduced Gas Locking

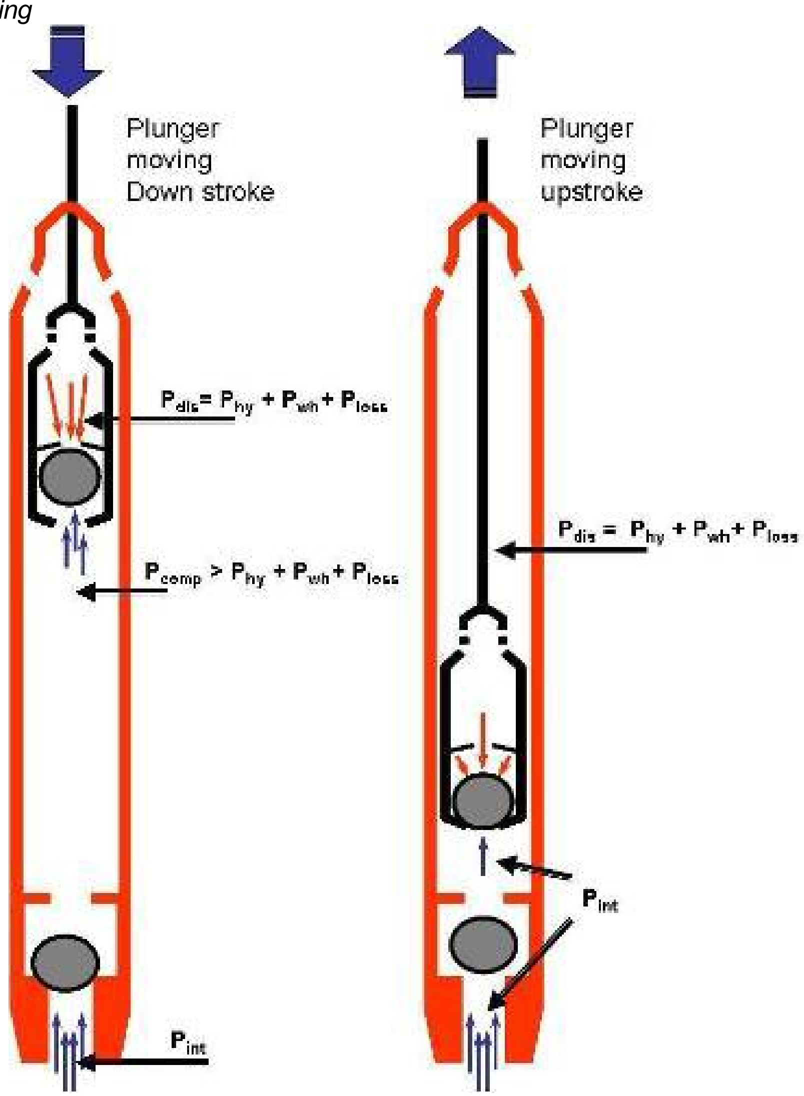


Figure 39: Pressures across the downhole pump[7]

If free gas enters the pump it will fill a part of the volume below the plunger (depending on the amount of gas). Therefore a pressure is createdinside the pump barrel. At the beginning of the next upstroke the standing valve will not open again, until the p_{int} exceeds the gas pressure inside the pump. Therefore a part of the stroke is lost.

At the beginning of the downstroke the travelling valve will not open until the pressure below the plunger exceeds the p_{dis}. This will not be at the uppermost part of the stroke as the gas has to be compressed by the downstroking plunger until the increasing p_{comp} exceeds $p_{dis.}$ So also a part of the downstroke volume is lost. If the amount of gas entering the pump is large enough, that the travelling valve cannot open at all, gas locking occurs [7].

Therefore sucker rod pumps installed in wells which produce moderate to high amounts of free gas or produce near to pumped-off condition can have severe gas locking problems. One possibility to overcome gas locking problems may be to space the plunger in a way that it almost touches the standing valve at the lowest point of the downstroke. In this situation the un-swept volume below the plunger is reduced and the compression ratio of the pump is increased.

The compression ratio is defined via volume reduction:

$$CR = \frac{V_1}{V_2}$$

Where V_1 is the volume below the plunger at the top of the upstroke, and V_2 is the volume below the plunger at the end of the downstroke [51].

Due to an increase in the compression ratio of a pump, p_{comp} can be modified (also increased) in order to reach the necessary Δp to open the travelling valve. Due to the fact that the compression ratio depends on the volumes inside the pump barrel, longer strokes and larger pump diameters increase the compression ratios and therefore can reduce gas locking problems [35].

Application for Deliquifaction of Gas Wells

Due to the above mentioned resistance to gas locking the HRPI can also be used for de-watering gas wells. In this case it is an advantage when a very flexible pumping can be achieved. If gas wells are de-watered with time runners, water is refilling the well when the pump is stopped and if the pump is started again, the back-pressure on the formation created by the weight of the water column in the well may hold back gas which could be produced otherwise.

Comparsion of Hydraulic Drives for Sucker Rod Pumps

Comparison of hydraulic drives for SRPs			
	R7	Hydraulic Pump Jack	Subsurface Hydraulic Rod Pump
Manufacturer	BoschRexroth	ECOQUIP	HRPI
Pump Type	Electro-hydraulic pump drive	Hydraulic Pump Jack	Subsurface hydraulic Rod Pump
Stroke Length	192-100 [in]; 8-4 [strokes/min]	9000-6: 144 [in] 9000-9: 240 [in] 2-6 [strokes/min]	240 [in] - 336 [in]
Weight	Weight: <3.000[kg] rod loads: max. 36,500 [lbs]	surface unit: 6,500 [lbs] Rod loads: -6: 35,000 [lbs] -9: 60,000 [lbs]	surface unit: 2,500 [lbs] Peak polished rod load: 53,376 [lbs]
Flow Range	260-530 [bbl/d]	ID 1,5 [in]: max. 193 [bbl/d] ID 2,75 [in]: max. 648 [bbl/d]	
max. Setting Depth	around 1.400 [m] (test operation Wintershall)	average around 7,000[ft]/2130 [m]	no information available
Power Source	electric motor	Electric motor: 50 [HP] Gas Motor: Ford 300 and GMC 350: 110 [HP] (Ford)	480/460 VAC three-phase electrical power; NEMA B electric motor: 10-250 [HP]
Deviated Wells	no tubing rotator; very limited	tubing rotator possible; limited	limited; max. dogleg severity: 10°/100ft; tubing rotator possible
Installation Time	3.5 [hrs]; additional time to make up hydr. connections needed	no information available	3 [hrs] @ installed rod string
Footprint	depending on max. stroke length; Landau: 4 [m] above surface, but very slender system; additionally hydraulic aggregate: ~container size	depending on max. stroke length; overhead clearance above well head: 10 [m]; system is very slender; hydraulic aggregate: 10x4x7.5 [ft]	very low; just hydraulic aggregate
Noise	quite loud; additional noise protection crucial	no information available	designed to stay below 60 [dB]; additional noise protection possible
Other Advantages			reduced down-hole pump wear due to less strokes/minute

Table 14: Comparison of Hydraulic Drives for SRPs

Hydraulic Submersible Pumps

Lufkin Hydraulic Submersible Pump

The technology for this pump has been developed by Global Energy Services Ltd[4] and is named "Activator". In 2008 a Global/Lufkin Joint Venture has been agreed with International Lift Systems (a 100% subsidiary of Lufkin). Lufkin therefore develops the market and service worldwidefor the pump, which is now called HSP [45]

Main Principle

Components

Down-hole Equipment

The submersible pump consists of a Corrosion Resistant Monel Coated Carbon Steel Housing, with Nitride coated interal components and a nickel alloy shaft. The internal space is divided into two chambers by middle gland seals, the upper one filled with production fluid, the lower one filled with hydraulic fluid. The piston head divides each chamber into two sub-chambers.

A nickel-alloy shaft travels inside the pump. Three strings lead downwards to the pump: two strings transporting the hydraulic fluid to the pump, one mounted at the top of the lower chamber, the other one at the bottom of the lower chamber.

The production fluid intake is positioned at the top of the upper chamber, as well as the production valve. Another intake of production fluid is mounted at the lower end of the upper chamber[47].

The system itself has an OD of 3.6 in, which fits into 4.5, 5.5 and 7 in casing.

Also integrated into the system and mounted on the lower end of the pump is a self-flushing, 10 spiral- slot 0.012insand screen.Other specialized screen sizes are possible and can be matched with the necessities of the well in question. It is a 1.3 m tube with an OD of 1.5 in[48][49][50].

For the coiled tubing deployment, different possibilities exist: A triple-string configuration is one possibility, another possibility is an encapsulated coil, a combination consisting of jointed tubing and coil etc.

Also a fourth tubing string for gas injection can be added[48].

[4]Global Energy Services Ltd has changed its name into „Raise Production Inc." in November 2011 [46]

Wellhead

Because of the triple-encapsulated tubing special wellhead equipment is necessary. The wellhead is called “Tri-Coil Wellhead”. It provides 3 crossovers connected to 3 tubing hangers an an annular bag (Figure 40) [50].

Figure 40: Tri-Coil Wellhead [50]

Figure 41 shows the installation of the Tri-Coil Wellhead.

Figure 41: Installation of the Tri-Coil Wellhead [50]

Surface Equipment

The surface unit consists of either a 22-25 HP Nissan Industrial Engine, which uses propane or field gas as power source, or a 10 HP electric motor, combined with a 15 GPM Compensated Hydraulic Pump, which are positioned in an sound dampened enclosure. Dimensions for the surface unit are 2.5x1.0x1.0 m. The second possibility is a solar panel powering system[52].

Operating Principle

During the upstroke, hydraulic oil is pumped down-hole to the bottom of the lower chamber, forcing the piston into an upward movement. Hereby the hydraulic fluid filling the upper part of the lower chamber is forced out of this chamber into the string. For the downstroke, the system acts exactly the other way round: hydraulic fluid is pumped into the upper part of the lower chamber, forcing the piston into a downwards movement. The hydraulic fluid is drawn out of the lower part of the bottom chamber.

The main intake of the pump is mounted inside the integrated sand screen. There are two of them, leading to either the top or the bottom part - the“cooling chamber” - of the upper chamber. The intake valve, which leads to the upper part of the top chamber is the real production intake valve. It opens during the downstroke, and the fluid enters the production chamber. Now, during the upstroke movement, the production valve on the top of the upper chamber opens, and the fluid is forced into the production tubing string. While the upstroke movement, some part of the production fluid is drawn through another intake valve into the cooling chamber. When the piston strokes downwards again, this fluid is forced out of this part of the chamber and flows back into the sand screen, hereby “flushing” it[49].

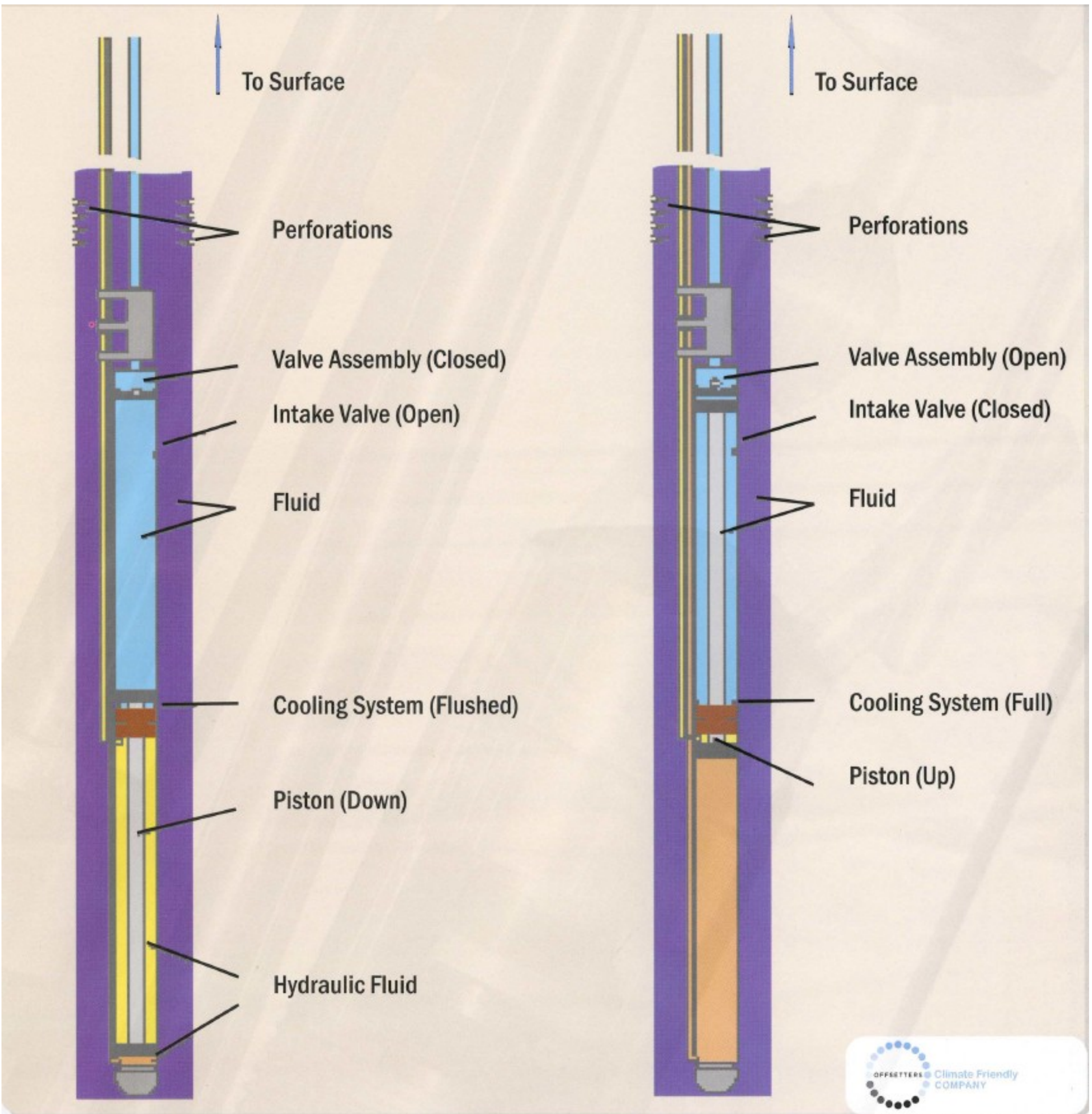


Figure 42: Operating Diagram of the HSP[47]

It is possible to adjust the pump rate flexible, and instantaneous using a flow divider. This is a flow control valve which is positioned in the surface equipment. As described above, the hydraulic oil flow downwards moves the piston and therefore controls the number of strokes. The speed of the pumped oil determines the frequency of each cycle[49].

To push the piston down, a certain amount of hydraulic oil is needed and slightly less for forcing it downwards again, so around6.6 l (1.75 gal)of hydraulic oil percycle. To react on changing production conditions, these rates can be changed and therefore pumping frequency can be changed easily [49].

Production rates will be dictated by the frequency of the pump. One stroke can max. produce 5.7 l (1.5 gal), so the daily production depends on the number of strokes[53].

Gas Locking

The pump is basically designed to withstand gas locking with a compression ratio of over 500 [47]. Gas locking normally means, that due to the missing weight and pressure of a fluid column, the down-hole valves cannot move anymore and the pump “locks”.

Explained in detail: The upper chamber of the HSP, normally containing the to-be-produced-fluid, consists of two volumes. V_1 is the volume of the piston chamber at the end of the downstroke, V_{2a} is the so-called “clearance volume” – the volume of the piston chamber which still remains at the end of the upstroke [51].

In presence of gas, also two volumes exist inside the pump: V_1, which is the volume in the piston chamber at the end of the downstroke, so the same V_1 as above; V_{2b}, which is now the volume of the compressed gas at the end of the upstroke;

Similarly, two pressures exist during the production cycle: p_1, which is the pressure of the gas entering the chamber; p_2, which is the pressure of the gas when compressed at the end of the upstroke.

$$\frac{V_1}{V_{2b}} = \left(\frac{p_2}{p_1}\right)^{\frac{1}{r}} \qquad \text{[a]}$$

r is the ratio of the specific heats of the gas $\frac{c_p}{c_v}$, for natural gas mixed with air, this value is normally 1.29. c is the specific heat of a substance or – in this case – a mixture, in SI-Units: $c = \frac{J}{kg*K}$;c_p is the specific heat of the mixture at constant pressure, c_v is the specific heat at constant volume.

Gas locking will now occur, when the clearance volume V_{2a} is less than the critical volume relevant to gas locking V_{2b}[49].

Criterium for Gas Locking: $V_{2a} \leq V_{2b}$

Table 15shows calculated values for V_{2b} (using [a]). P_2 thereby is calculated as the hydrostatic pressure in pump setting depth:

$$p_2 = \rho * g * H$$

With:

ρ… fluid density, here taken as the density of salty water, ρ=1,100 [kg/m³]

g…gravity acceleration, g=10 [m/s²]

H…the pump setting depth in m

V_1 is the calculated volume of the piston chamber

$$V_{2b} = \frac{ID^2}{4} * \pi * h \,,$$

With

ID…internal diameter of the HSP, ID=2.5 in

h…stroke length, in

Pump Setting Depth H	Stroke length h in	P_1bar	P_2bar	V_1 [in³]	V_{2b} [in³]
1,500	73.28	2.41	165.7	359	13.5
2,500	72.55	3.45	343.2	356	10

Table 15:Calculated Values for V_{2b}[49]

As the pump has a clearance volume of about 2 in³, the criterion for gas locking is not reached in any calculation ofTable 15, and can hardly be reached at all.

Heat Trace

The HSP system uses the heat of the pressurized oil to prevent wellhead freezing. The hydraulic oil heats while pumping due to pressurizing. Therefore the hydraulic oil lines are routed along or around the production line, and the line system as a whole is isolated. The production line acts as a heat exchanger and reduces or eliminates the necessity of cooling.At the same time the hydraulic oil and prevents freezing of the water in the production line[49].

Maintenance Interval and Mean Time between Failure (MTBF)

Table 16 shows the maintenance intervals recommended by the manufacturer.

There is no design specification for the number of cycles possible on the pump. Many factors will contribute to the run life of the system. According to the manufacturer the run life varies between 2-3 years [53].

The run life strongly depends on the well conditions and the proper design of the sand screen. Excessive sand or solid production may decrease the MTBF severely[54].

System	Maintenance required	Recommended frequency
Engine	Monitor engine oil temperature using engine oil thermometer	Daily
	Change oil	Every 2-3 weeks
	Check engine coolant levels	Monthly
	Visually inspect all lines to check for hydraulic oil leaks	Always be alert for leaks; perform a thorough inspection daily
	Ensure engine rpm is in 1800 to 2200 range	Daily
Hydraulic filter	Monitor hydraulic oil filter gauge	Daily
Hydraulic oil	Monitor hydraulic oil temperature by using hydraulic oil thermometer	Daily
	Check oil by taking a dip and ensuring oil is not black, dirty or plugging up; change if necessary	Every 3 months
	Change Hydraulic oil in surface equipment by draining old oil and replacing	Every 6 months

Table 16: Recommended maintenance intervals according to the manufacturer[53]

Possible Configurations

The HSP can effectively produce larger amounts of fluid up to a depth of 1,530 m (5,000 ft) and can produce at production rates up to 24 m³/d (150 BFPD). The device has an OD of 3.6 in and fits into 4.5, 5.5 and 7 in casing. As already mentioned, 3 feed throughs are required for the down-hole pump: one production tubing and two hydraulic fluid pumping tubings [48].

The pump has a length of 5.59 m (18.33ft) and weighs around 114 kg (250.8 lbs) [47]. According to the manufacturer the design of the pump should provide full function in *"virtually any position"*. It is recommended to set the pump in the heel section of the well to get best results in unloading. Setting in a deviated section may put stresses on the pump itself, therefore is not recommended [53]. In one application (horizontal coalbed methane well) the pump has been operating for more than two years at an overall deviation angle of 86.5°. The pump has been set in a short straight section of this well [55].

Possible are a triple-string coil configuration, an encapsulated coil, a joint-tubing for fluid production and 2 coils for the hydraulic fluid and other variations. It is also possible to add a fourth string for gas injection [48].

If working with a triple-string coil tubing, the required OD of the production string is 31.75 mm (1.25 in) and the required OD of the hydraulic strings is 25.4 mm (1in) [47].

Encapsulated Coil

The main manufacturer is CJS Coiled Tubing Supply Ltd for the encapsulated coil. The product is called FLATPAK. It is able to convey up to four strings in one coil down-hole. The standard material for the tubings is carbon steel grade 70/80k[5] which is also available with external FBE coatings for mild H_2S/CO_2 environments. Alternative materials are 304 SS[6], 316-L[7] SS, lean duplex alloy 19D[8], or, for low pressures, also a “hi temp” acid resistant thermo plastic tube is possible.

The encapsulating material is vulcanized thermoplastic. It can be applied in temperatures from below 0°C up to 135°C and shows chemical resistance to the chemicals used in the oilfield [59].

Description	Dimensions	Weight lbs/ ft
0.75” x .075”	1.10” x 1.80”	1.52
1” x 5/8” x 1”	1.25” x 3.07”	2.88
1” x 1” x 1”	1.25” x 3.45”	3.45
1.50” x 1.0” x 1.0“	1.75” x 2.95”	4.50

Table 17: Configuration possibilities for the FLATPAK[59]

For the HSP the normally the triple-configuration 1 x1x1 in OD is used [60].

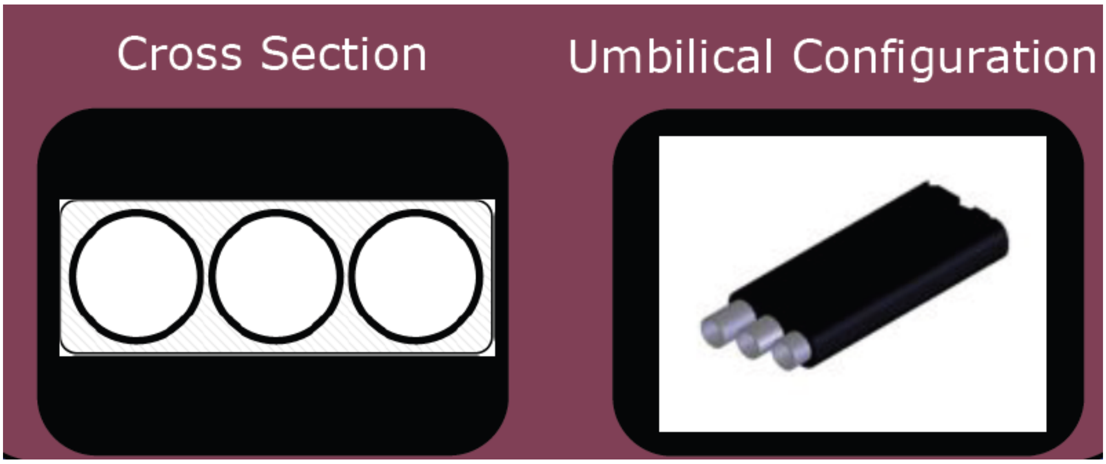


Figure 43: FLATPAK Scheme [59]

The installation of the FLATPAK is possible with conventional Coiled Tubing Trailers.

[5] ASTM/ASME grade

[6] 304 SS:Fe, <0.08% C, 17.5-20% Cr, 8-11% Ni, <2% Mn, <1% Si, <0.045% P, <0.03% S[56]

[7] 316-L SS: Fe, <0.03% C, 16-18.5% Cr, 10-14% Ni, 2-3% Mo, <2% Mn, <1% Si, <0.045% P,<0.03% S[57]

[8] Special Stainless Steel Grade: Fe, max. 0.03% C, max. 4.0-6.0 Mn, max. 0.04 P, max. 0.03 S, max. 1.0 Si, 19.5-1.5 Cr, 1.0-3.0 Ni, 0.6 Mo, 0.05-0.17 N [58]

The additional equipment which is necessary for the application of FLATPAK, injector chains, BOPs, hanging and pulling equipment is also produced by the manufacturer [59].

Monitoring and Diagnosis

One of the big issues using this pump is to determine if the pump is operating in “pumped-off” state, meaning if it is running without any fluid produced. This is done by monitoring the pressure of the hydraulic oil leaving the surface pump. If the pump has to lift water, it has to create a pressure peak to push the weight of the water column upwards. This peak will show up at the pressure gauge, which is installed at the well head.

Now when there is no water to produce, the pump doesn’t have to lift the water column. Therefore no additional pressure has to be created by the surface pump and the main driver’s rpm will increase instantly in order to compensate for the reduced resistance [49].

Setting Procedure

The system is run down into the well on the FlatPak, which takes, depending on well depth, not much more than one hour on average. The surface unit as a whole can be loaded on (and off) a trailer and set on the well site. Just two fluid connections and four fittings have to be made.

Average HSP installation schedule:

Normally it takes about 2.5 hours for rigging up, one to two hours for RIH, tying of the hydraulic lines to the surface unit and the production line to the pipeline in around two hours. Then the system can be started [49].

The time specifications above are just valid when using coiled tubing. It is also possible to deploy the HSP on conventional steel tubing, which increases the completion time due to the threadconnections of steel tubing, a work over rig is necessary.

Economics

CAPEX are depending on depth:

52,513 € (70,000 $ CDN)[9] for 750 m up to 71,270 € (95,000 $ CDN) for 1,500 m. Main cost driver here is the tubing, therefore CAPEX are strongly depth-dependent.

OPEX are also strongly depth dependent because of the increasing energy requirement with increasing depth. They also depend on the maintenance costs [61].

Advantages/Disadvantages

On behalf of the first manufacturer of the HSP, Global Energy, McCulloch and Moorhouse (2006) did a comparative survey to establish advantages and disadvantages of the new HSP

[9] Wechselkurs 06.04.2012: 1 $ CDN = 0.75 €

technology. Therefore they compared the HSP performance with a mechanical pump jack, a PCP, and a hydraulic pump jack. The advantages and disadvantages below are primely based on this report.

Variable	Parameter	Unit
Well Depth	1450 (4757)	m (ft)
Capacity	5 (31)	m³/d (bbl/d)
Tubing Size	73 (2 7/8)	mm (in)
Location	Strathmore, Alberta, Canada	
Sound Attenuation	Non-sound attenuated and sound attenuated options were taken into consideration	dBA
Prime Mover	Gas	
Application	De-Watering	

Table 18: Operating Parameters[61]

Table 18 shows the basic data of the wells where the comparative study was done. In addition, Table 19 presents the other pump technologies which have been used to establish advantages and disadvantages of the HSP. The values of the Hydraulic Pump Jack system in the following tables is not one of the systems described in this Master Thesis. Obviously the parameters of the HPJ systems vary a lot depending on the way how they are installed[61].

Assembly	HSP	CPJ	PCP	HPJ
Prime Mover	Nissan CG 13	Arrow C-46	Chevy V6 Hydraulic Skid	3.0L Vortec GM Motor
Pump Model	Activator[10]	Lufkin C-80D-109-48	Moyno 24S4	CH 10-64 ICI Artificial Lift
Drive Head			Moyno DHH Hydraulic Drive Head	

Table 19: Equipment and Pump Model of the technologies used for comparison[61]

Advantages

Installation

The above described ease of installation and deployment leads to very low set-up-times – normally the system can be installed in half a day. No full service rig is required the whole process can be done by a coiled tubing rig. In comparison to the other systems, which have been analysed by the authors, the set-up of the HSP is up to 300% faster (compare Table 19).

[10] HSP

Technology	Set up time – best case (days)	% difference
HSP	0.5	0
CPJ	2	300
PCP	1	100
HPJ	1.5	200

Table 20: Installation time comparison[61]

Not contained in the set-up times of Table 20 is the assembly of the CPJ, which in most cases has to be done on site and may need an additional day. For the HPJ the attaching of the surface unit to the rod string has to be added, normally half-a-days work. Also the time for the surface unit connection for the PCP has to be added, but that is taking less time than for the other ones.

Also less equipment is needed for the installation of the HSP in comparison to the other options due to the fact, that just a coiled tubing trailer is needed[61].

Noise

The whole surface unit of the HSP is contained in a sound enclosure. This brings down the noise to 55.4 [dBA], which is significantly quieter than of the compared systems (Table 21).

System	Prime Mover	Highest Level (dBA)
HSP	Gas Engine	55.3
CPJ – Metal shack	Gas Engine	56.5
CPJ	Electric Motor	64.0
PCP	Electric Motor	57.0
HPJ	Gas Engine	63.3

Table 21: Noise Pollution of the single pump systems[61]

It is possible to bring the noise level for every pump system down, when using the right sound attenuation system. The advantage of the HSP is, that the sound enclosure is included in the HSP system and therefore no additional noise protection will be necessary[61].

Footprint and visual Impact

The visual footprint of the HSP shows advantages versus almost all other systems, only the PCP shows similar properties.

System	Footprint (m²)	Height (m)
HSP	3.25	1
CPJ	10.25	4.2
PCP	3.00	1
HPJ	3.0	1.54

Table 22: Visual Impact of the different pumping systems[61]

As shown in Table 22 the PCP shows a slightly smaller footprint,if a sound attenuation is not required [61].

Leak potential

In contrary to the CPJ, HPJ or PCPs, the HSP doesn't have any rotating or reciprocating parts which would impede to repair small leakages at the well head. Additionally the containment is also a leakage protection around the prime mover and the pump which pressurizes the hydraulic fluid[61].

Deviation Angle

The positive displacement design enables the pump to work in any position. Nevertheless it is recommended to set the HSP in the heel section of the well. This is an advantage especially in comparison to all other systems which are dependent on reciprocating or rotating rods which may show excessive wear in case of high deviation angles or cannot be applied at all. All pump jack systems are restricted in terms of deviation angle because the main driving force for the downstroke is the gravity (the rod weight). The rods have to have the possibility to fall freely to provide proper operation[53].

Wear and sand filter

The design of the pump is rodless, so no reciprocating and rotating parts are directly exposed to the unfiltered reservoir fluids. Due to the integrated sand filter possible wear caused by sand or solid production in the pump cylinder is reduced. The integrated sand filter also prevents other damage which would be a consequence of excessive sand production, as e.g. corrosion or blocked valves[48].

Operation in pumped-off mode

The pump is designed as "positive displacement" pump. In normal operation residual water is always present in the upper chamber of the pump, even at the end of the upstroke. Therefore in a pump-off situation residual water is still contained in the chamber, but level is too deep so the piston will not produce a flow through the check valve. Basicallyit is possible to pump 100% gas. Because of the residual water in the chamber a certain cooling exists for the piston although operation in pumped-off state is not recommended for more than eight hours. In this case the middle gland seals can run dry[49].

Maximum drawdown

The above mentioned possible operation in pumped-off mode also provides the possibility to lower the fluid level in the pump to an absolute minimum. A certain fluid level inside the casing therefore means a certain pressure in the casing which also creates backpressure on the producing formation. Due to the fact that maximum flow can only occur with maximum pressure drawdown which is produced by lowering the fluid column in the pump to a minimum [39].

Low required NPSH – Net positive suction head

If the pressure at the suction side of a pump is too low the fluid could start boiling. This would be if the pressure in the fluid is lower or equal than the vapour pressure of the fluid at the actual temperature. The results of boiling would be a reduced efficiency, cavitation[11] and pump damage.

Now basically the Net Positve Suction Head required is the NPSH which is required for save pump operation and determined by the manufacturer, while the Net Positive Suction Head available is the NPSH which is available in the system. The $NPSH_a$ should always be higher than the $NPSH_r$.

The Net Positive Head is the difference between the static pressure in the fluid at the pump intake minus the vapour pressure of the fluid at the actual temperature and converted to head.

Static pressure of the fluid at the pump intake derived by the Bernoulli-Energy-Equation:

$$p_s = h_s * g * \rho - \frac{v_s}{2}\rho \qquad (1)$$

With p_s….static pressure at the pump intake

h_s…suction head close at the pump intake

v_s…velocity of fluid

g…acceleration of gravity

ρ…density of the fluid in question

The liquids vapour pressure can be expressed as:

$$p_v = h_v * \rho * g \qquad (2)$$

Where p_v …vapor pressure of the fluid at a certain temperature

h_v…vapour head

[11]Basically „cavitation" means that bubbles occur in the liquid and collapse again [63]

Transforming on hs and hv and combining formulas (1) and (2) gives than the Net Positive Suction Head available:

$$NPSH = h_s - h_v \tag{3}$$

or

$$NPSH = \frac{p_s}{g * \rho} + \frac{v_s}{2 * g} - \frac{p_v}{g * \rho} \tag{3a}$$

When speaking of hydrocarbons the NPSHr given is for use of cold water and has to be adapted for the vapour release properties of complex organic liquids [62].

Now as shown in Table 24the different artificial lift systems require different $NPSH_r$s due to their function principle and design. The HSP requires hereby a very low $NPSH_r$ which means it can be used with almost no or very low pressure on the suction side of the pump – corresponding to a very low reservoir pressure. The system is therefore almost able to suck fluid out of the producing formation. According to the manufacturer the deployment of the HSP added 0.75 [Bcf] of recoverable reserves in two mature low pressure gas wells [47].

Artificial Lift Technology	**Net Positive Head, required**	**Minimum Pressure**
Jet Pump	183 [m]	18 [bar]
ESP	91 [m]	9 [bar]
Rod Pump	30.5 [m]	3 [bar]
PCP	18 [m]	1.8 [bar]
HSP	0.3 [m]	0.07 [bar]

Table 23: $NPH_r$for competing artificial lift systemsl – SI Units [48]

Artificial Lift Technology	Net Positive Head - Required	Minimum Pressure
Jet Pump	600 ft	260 psi
ESP, Electrical Submersible Pump	300 ft	130 psi
Pump Jack/Rod Pump	100 ft	43 psi
Progressive Cavity Pump (PCP)	60 ft	26 psi
Hydraulic Submersible (HSP)	1 ft	1 psi

Table 24: NPH_r for competing artificial lift systems – Oil Field Units[48]

Disadvantages

Energy Efficiency

To determine the efficiency and establish benchmarks for the comparison with the other pump systems, the energy efficiency has been calculated as [HP/bbl], so as the theoretical horsepower requirements for each barrel pumped. Table 25 shows these efficiencies for a pumping depth of 1450 m.

System	Efficiency (HP/bbl)	Efficiency (kW/bbl)
HSP	0.175	0.13
CPJ	0.08 – 0.10	0.06 – 0.07
PCP	0.08 – 0.10	0.06 – 0.07
HPJ	0.15	0.11

Table 25: Theoretical Pump Efficiencies[61]

The numbers in Table 25 show a significant lower efficiency for the HSP in comparison to especially the CPJ and the PCP, but also for the HPJ. Therefore the HSP is the least efficient of the competing technologies[61].

The theoretical calculated data differ from the experiences of the first applicants of the HSP. The general observation has shown that the HSP shows similar efficiencies as the CPJ.

Production volume as a function of depth

Due to friction losses in the production line the max. produceable volume is depth dependent. Figure 44 shows a daily-production (m³/d) vs. Pump Landed Depth (m) graph. “Pump Landed Depth” hereby means “setting depth” of the HSP. The red line is the benchmark for max. production at a certain depth, the blue points show the performance of already installed pumps[64].

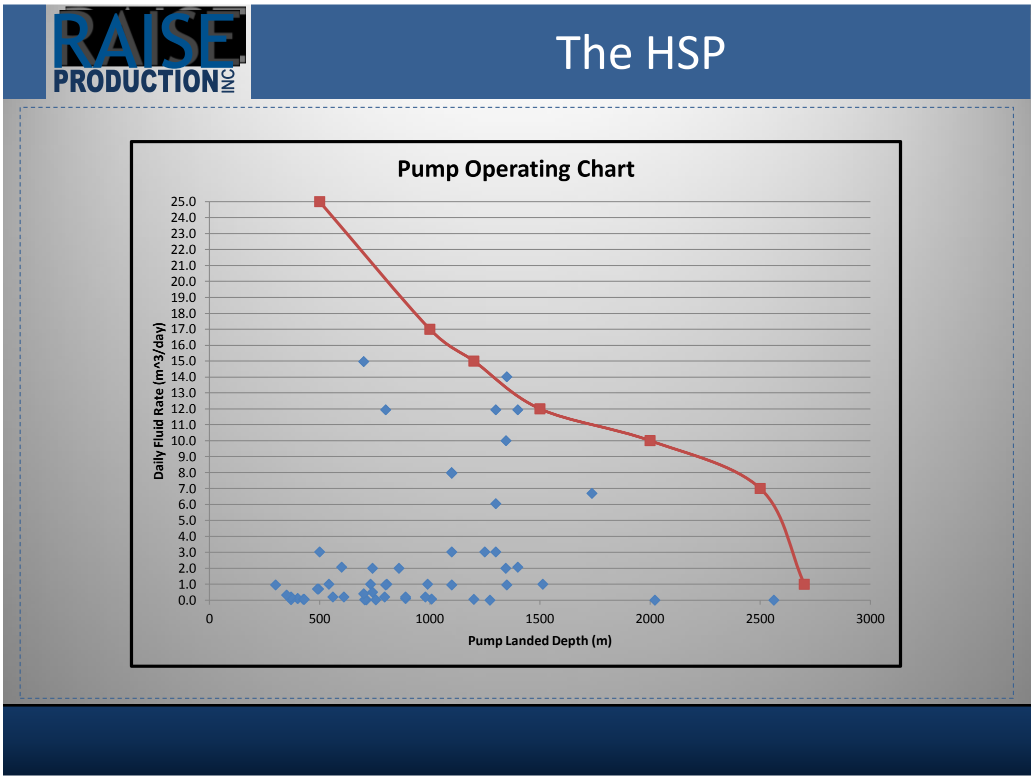


Figure 44: Depth dependency of production volume [64]

Economic Performance

When discussing the economic performance of a system, it is important to differ between Capital Cost and Operational Cost of a system. Capital Cost are usually defined as total cost for all the necessary equipment, manpower and time to purchase, deliver and install all components. The Capital Costs as well as the Operational Costs shown below are coming from Canada and it is not possible to transfer them one to one on Central Europe.

It is hard to say if the economic performance of the HSP is a disadvantage, because the capital costs are strongly depth-dependent due to the fact that the main cost driver is the tubing. Figure 45 shows the Capital Cost for the different pumping systems for different depths. The comparison shows that the HSP is more than the competing technologies depth dependentbecause the coiled tubing is the cost factor of the whole system. In 1450 m coiled tubing is almost one half of the CAPEX, in 1000m setting depth this value sinks to one third of the capital costs[61].

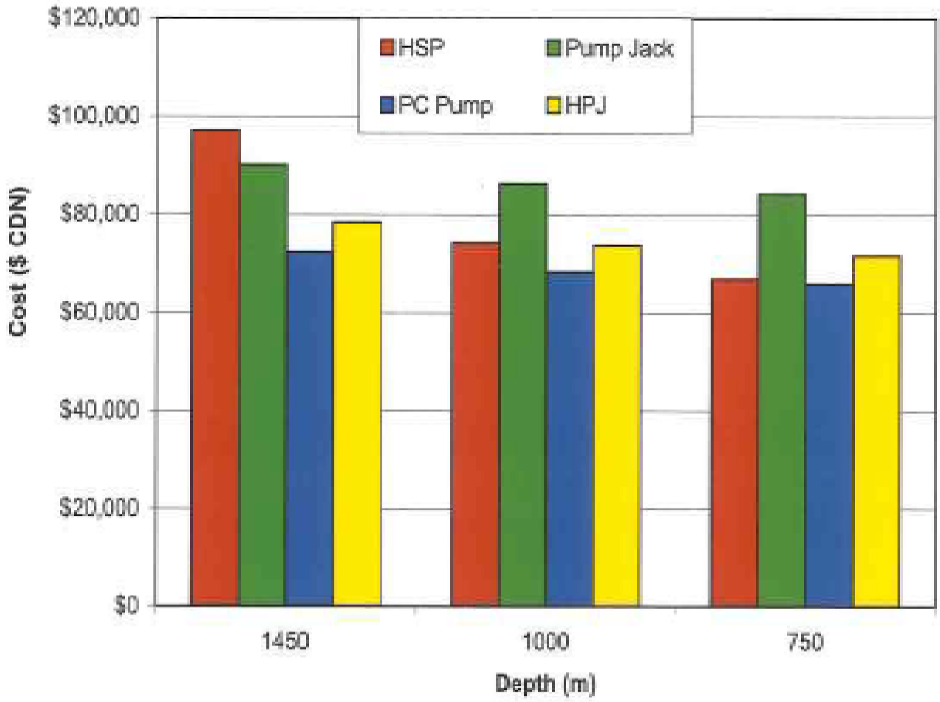


Figure 45: Capital Cost for different Depths [61]

The comparison shows that the HSP is more than the competing technologies depth dependent due to the fact that the coiled tubing is a big cost factor of the whole system. In 1450 m coiled tubing is almost one half of the whole CAPEX, in 1000m setting depth this value sinks to one third of the capital costs[61].

Not only the capital costs, but also the operational costs as e.g. the energy requirement of the pump are strongly depth dependent[53].

Power Supply by Solar Panel

As mentioned above a power supply of the HSP by solar panel is possible. This can be an advantage of the system in two ways: The most obvious way is the absolute independence on any “normal” power supply. The system could be installed in areas where no electricity is available and there would not be the necessity to supply a gas engine (especially if no or just little associated gas exists). Also powering artificial lift systems by solar power can be a possibility to improve the public acceptance of the petroleum industry.

It is possible to drive HSPs by Solar Panel if the energy requirement is very low. The energy requirment depends on the setting depth of the pump, therefore the Solar Panel stays a theoretical option of most applications[53].

SmithLift Hydraulic Diaphragm Electric Submersible Pump

Main Principle

Components

The HDESP – System contains two components: an oil field type submersible electric motor and two cylinders equipped with twin acting diaphragm tubes. The whole system is sealed against intrusion of wellbore fluids and filled with hydraulic oil. Each cylinder has its own intake and its own outlet valve. The motor is coupled to an internal pump which moves the hydraulic oil to and between the diaphragms. The system itself is enclosed in a stainless steel construction.

The cable is a 3 phase, 460 volt submersible power cable which is fixed to the tubing and sealed in the wellhead.

The surface controls are integrated into a surface control panel. The systems can also be equipped with a variable frequency drive [65][66].

Depending on the well conditions flow-bypassing shrouds or heat transfer methods can be installed. According to the manufacturer also an overload device in conjunction with a highly developed motor saver is necessary to avoid motor failures in case of voltage fluctuations or line failures [67].

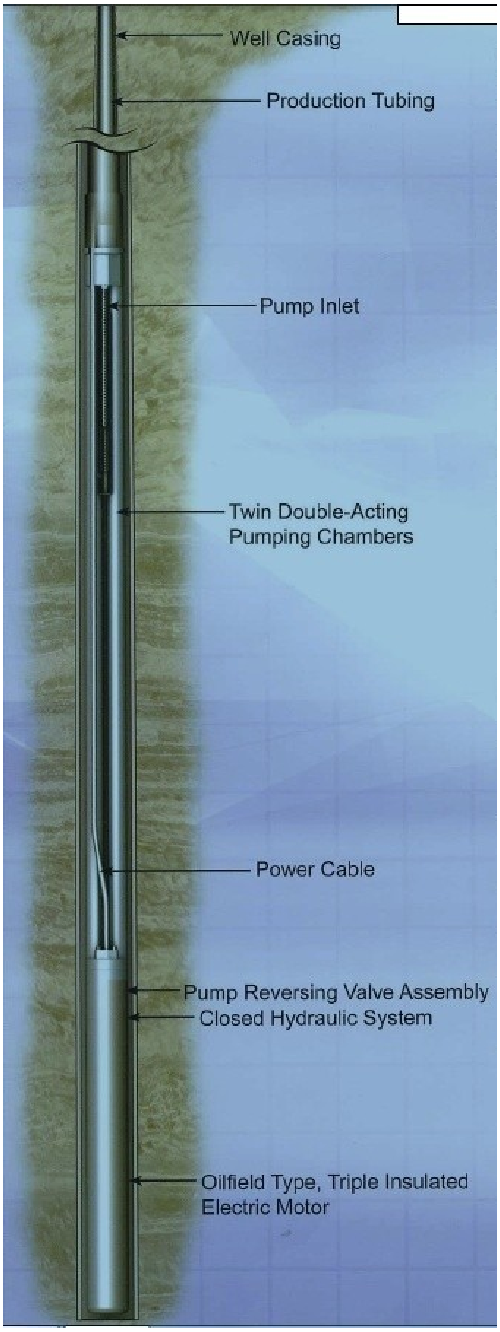


Figure 46: Components of the HDESP [67]

Operating Principle

The submersible motor drives the internal pump which pumps the hydraulic fluid from one diaphragm tube to the other. If the fluid is pumped into one diaphragm the diaphragm expands thereby displacing the oil well fluid in the cylinder through the opening outlet valve into the tubing. Then the hydraulic oil is pumped back into the other diaphragm, causing the inlet valve into cylinder one to open and to refill with production fluid. By this alternating displacement of fluid in the cylinder chambers a continuous flow is provided[65].

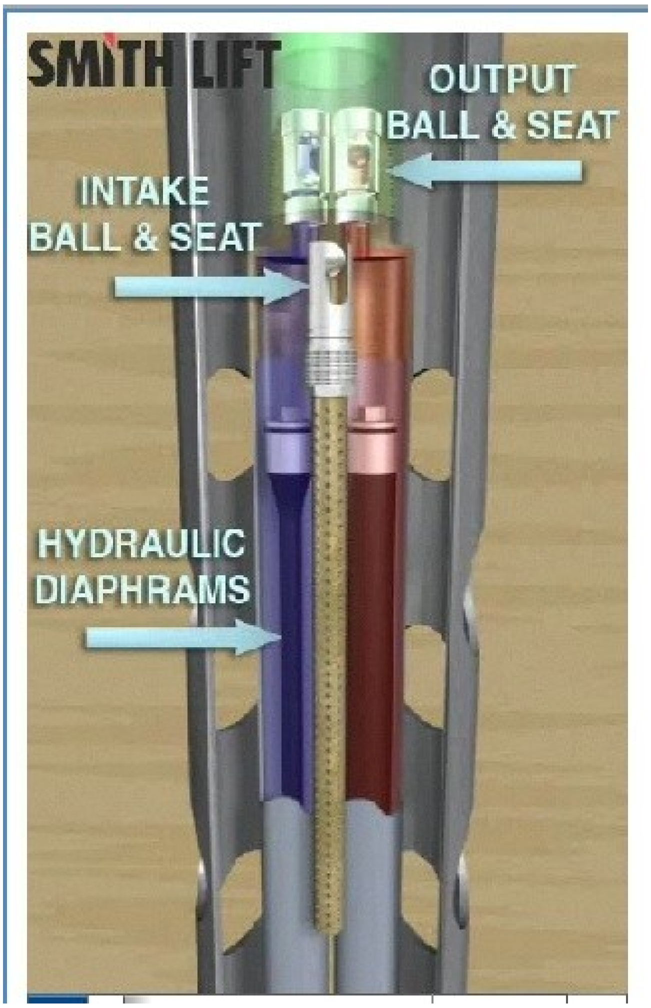


Figure 47: Operational Principle of the HDESP[68]

Solids and gas handling

Due to its twin-acting-diaphragm tubes the pump is able to produce efficiently at high gas ratios, and able to operate in pumped-off mode. Even producing 100% gas will not cause the oil pump to fail[67].

The housing is made of corrosion resistant stainless steel and the diaphragms isolate well fluids from the pumping mechanism. Therefore the pump can be used in aggressive chemical environments, e.g. in wells with H_2S/CO_2 content as well as in wells producing a relatively high solids ratio [69].

In cases where solids production can be expected a very small diameter completion should be chosen. This increases the fluid velocity, avoiding a back-settling of the solids on the downhole valves [65]. According to the manufacturer up to 2% solids can be pumped[71].

Surface controls

The surface control panel contains motor protection against voltage fluctuations, phase loss and ground faults as well as the pump off controls. Also possible are variable frequency drives. With the surface panel it is not possible to change the pump frequency and therefore the flow rate. It can operate the downhole motor at a fixed speed.

The variable frequency drive provides the possibility to change the rotational speed of the downhole motor. Therefore the pump cycle of the internal pump is changed which dictates the expansion of the diaphragms[66].

Heat Transfer

To provide proper cooling for the down-hole motor the pump should be landed within the fluid stream. If the pump is set in a thermally insulated section of the well, e.g. below the perforations, excessive heat build up will occur and - as a consequence – the motor failure. Best way to avoid this is to place the pump so that the to-be-produced fluid flows across the motor, a placement below the perforations should be avoided. If the well design requires a setting of the pump below perforations, shrouds or similar devices have proved to be best practice to provide proper motor cooling[67]. The flow shrouds increase the fluid velocities at the motor shell and therefore improves the cooling effect[65]. Also other heat transfer mechanisms exist. The motor is very sensitive due to heat build up, therefore cooling is absolutely crucial[67].

Configuration

Pump	
Length	2.13 m (7 ft)
Weight	41 [kg] (90 lbs)
OD	3.75 in
Material	Housing: corrosion resistant stainless steel Diaphragms: Nitrile
Cable	3 phase, 460 [V]
Production Capacity	3 pump sizes: 100, 150, 200 (BFPD)
Well	
Max. setting depth	760 m (2500 ft)
Deviation angle	20-30° (recommended by the manufacturer)
Casing ID	Min. 4.5 in
Max. fluid production	32 [m³/d] (200 [bbl/d])
Completion	
Tubing	Conventional steel tubing Coiled Tubing (corrosion resistant thermo-plastic tubings)
Tubing Diameter	OD: 2 3/8 in→ ID: 1.99 in OD: 1.0 in→ ID: 0.61 in

Table 26: HDESP Basic Pump and Well Data [66][65]

Table 26shows the pump dimensions and basic well data for HDESP application. The pump has to be designed for a certain production rate per day. Three pump sizes exist, for 16, 24, and 32 m³/d (100, 150 and 200 BFPD)[66].

As the pump is primarily designed for application in shallow CBM, gas and stripper oil wells, its design makes it possible to handle large amounts of solids. These wells normally produce on low flow rates. To get the large amount of solids to the surface without back settling on the valves, small diameter tubings are required. As shown in Table 27 these tubings allow fluid flow at relatively high velocities to ensure solids transportation to the surface [65].

Flow rate	1.99 in ID	1.99 in ID (SI)	0.61 in ID	0.61 in ID
100 BFPD	0.3 ft/sec	0.091 m/sec	3.2 ft/sec	0.97 m/sec
150 BFPD	0.5 ft/sec	0.15 m/sec	4.8 ft/sec	1.46 m/sec

Table 27: Fluid velocity comparison in different ID tubings [65]

Setting Procedure

The HDESP is a tubing-deployed pump. The setting procedure and the necessary equipment as well as the setting time therefore depends on the type of tubing used. As described below, conventional steel tubing is one possible configuration, the other will be Coiled Tubing[65].

So if conventional-tubing-deployed, a workover rig will be used for installation, if coiled-tubing-deployed a coiled tubing trailer will be needed. The pump is screwed on to the end of the tubing like a conventional ESP. For installing the cable one spooler will be used which carries the power cable.

Setting time also depends on the tubing type. Basically it is only the time needed to get the pump to the desired landing depth. For conventional tubing this will take longer because of the connecting-time of the joints, if coiled tubing deployed, setting time will be shorter[66].

Monitoring and Diagnosis

The system is equipped with a motor controller. This motor controller senses the power consumption of the Pump. If the fluid level drops or the pumped-off state is reached and the HDESP is just pumping gas, the power consumption decreases. At the surface control panel a critical value for the power consumption can be set. If this value is reached the motor will shut off automatically, preventing an operation in pumped-off mode [66]. This system also eliminates the need of downhole pressure sensors and fluid level gauges[65].

The system can also have an automatic timer with which it is possible to program a certain down-time[66].

Economics

Type of Costs	Costs [$]	Costs [EUR]
CAPEX	~50,000	~ 38,400
OPEX		
Energy costs	~600.0 /year	~ 460 /year

Table 28: Economics of the HDESP [66]

For the HDESP the information about the economics is very rare.

Advantages/Disadvantages

Advantages

Footprint and Surface Profile

The HDESP provides a very small footprint and visibility. At the surface just the surface control panel or the Frequency Speed Drive is needed, both being quite small devices.

Figure 48: Typical Well Head Configuration[70]

Figure 48 shows a typical well head of a HDESP well. It can be seen that the well shows optimum overhead clearance and due to the fact that just the cable is sealed into the well head leakage from the stuffing box is prevented[65].

The whole system is downhole, therefore noise pollution is not an issue as well [65].

Net Positive Head

The HDESP has a very low net positive suction head requirement. This allows a maximum fluid drawdown by lowering the fluid- to – pump intake to within inches without cavitation[71].

Gas and Solids Handling Capability

The HDESP can be used in high gas/ high solids rate production applications as mentioned above. It can be used in applications where gas locking or abrasive wear may be a problem for ESPs or rod pumps. Gas locking has never occurred in field application [65].

Economics and Efficiency

As mentioned above the HDESP is a pump with a main application in shallow, low-rate gas or oil wells. Schlumberger who markets the HDESP shows two studies, one stripper oil field and one CBM field which were produced by conventional beam pumps and ESPs.

In both fields the mean time between failure (MTBF) increased using the HDESP, resulting in fewer costs for pulling and repair and in no production loss due to pump failure. Therefore the HDESP showed improved operating economics [69][72].

Another study has been conducted comparing the energy efficiency of artificial lift systems in shallow, low volume wells. Therefore shallow, water-producing wells have been chosen. Flow rates and power were measured over a four-day period. The compared systems were a conventional beam pump, an ESP and the HDESP[73].

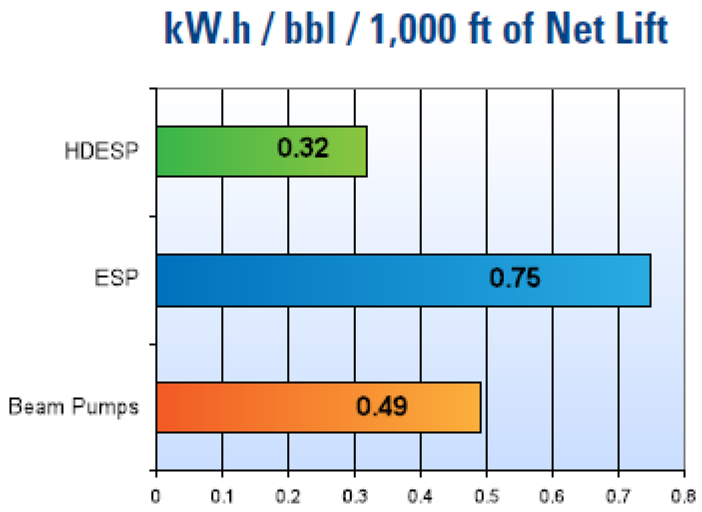


Figure 49: Average Power Consumption for a net lift of 1,000 ft[73]

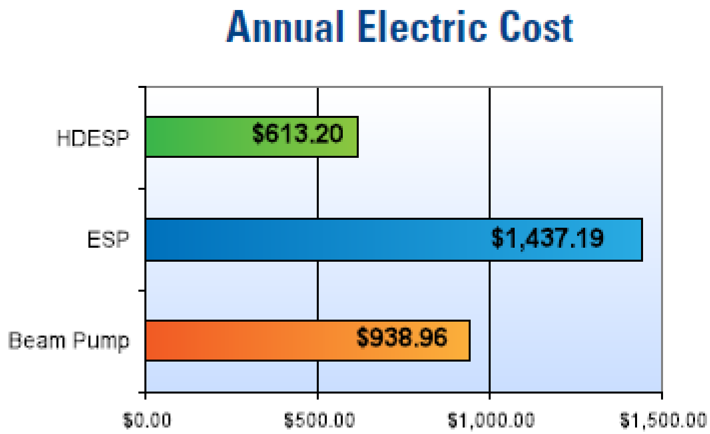


Figure 50: Annual Electric Cost Comparison [73]

Figure 49 shows the average power consumption for the compared pumping systems to lift one barrel fluid over 1,000 ft (305 m). The HDESP shows the lowest power consumption, resulting in significantly reduced annual electric costs, shown for a 32 m³/d (200 bbl/d) well with a net lift of 305 m (1,000 ft). The calculation for Figure 49 has been made with an average electricity cost basis of 0.07 USD/kWh[73].

Disadvantages

Only possible for verticle or slightly deviated wells

The HDESP can only be used in wells producing from depths not deeper than 2500 ft (760 m). This limits the possibilities of an application of the HDESP also in vertical wells.

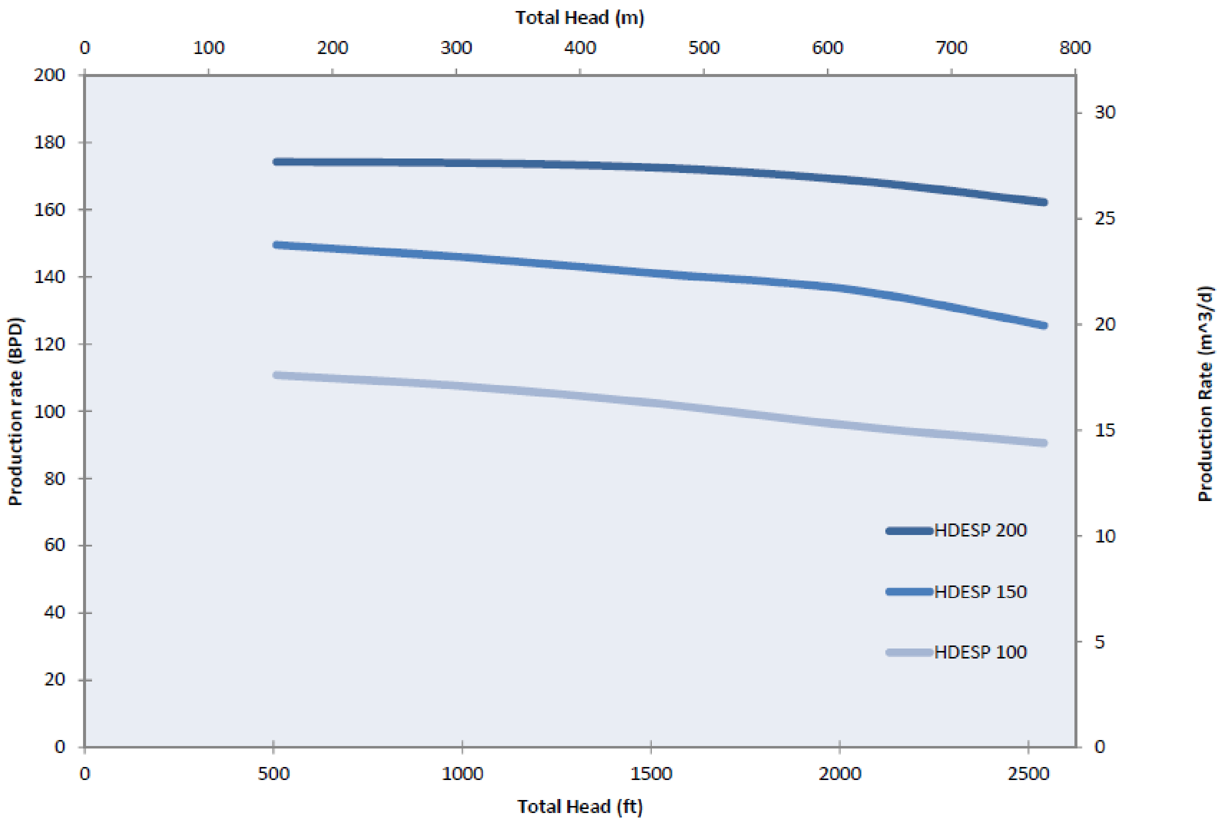


Figure 51: Depth Dependency of Production Rate for the three Pump Sizes[66]

Figure 51 shows the relation between pump setting depth and production rate. The depth dependency of the possible production per day is not that relevant as it is for the HSP. Therefore the whole production capacity cannot be used for applications below 183 m (600 ft) which additionally limits the already shallow application depth [66].

As also explained above the HDESP can only be used in vertical wells or in ones in a max. deviation angle of 30°. This further narrows down the application possibilities of the HDESP [66].

Additional Surface Equipment for Variable Pump Frequency needed

In contrast to the HSP which allows a very flexible adaption of pump settings, the HDESP needs additional equipment, a variable frequency drive, for adjusting pump frequency [67]. Basically the fluid production of the well has to be known, depending on this fluid production the internal pump of the system is chosen when designing the completion. The three lines shown on Figure 51 show the three different possible internal pumps of the HDESP and the achievable flow rates.

Comparison of HSP and HDESP

Comparison of technical data		
	HSP 3000	HDESP
Manufacturer	Lufkin	SmithLift
Pump Type	Hydraulic Submersible Pump	Hydraulic Diaphragm Electric Submersible Pump
Technical Data Down-Hole Pump		
Length	18.33 [ft] / 5.59 [m]	8 [ft]/ 2,4 [m]
Weight	250.8[lbs] / 114 [kg]	120 [lbm]/ 54 [kg]
OD	3,6 [in]	3,75 [in]/95,3 [mm]
Flow Range	1-150 [bbl/d]	200 [bbl/d]/32 [m3/d]
max. Setting Depth	up to 5.000 [ft]	2.500 [ft]/760 [m]
Casing	4.5, 5.5 and 7 [in]	min. 4,5 [in]/114,3 [mm]
Tubing Spec.	Triple-String Coil configuration, Encapsulated Coil, Jointed Tubing and Coil, production string OD: 1.25 [in] hydraulic strings OD: 1 [in]	Steel and Coiled Tubing possible; to avoid solid settling on pump discharge or checkvalve: smaller tubings for higher fluid velocities 1,99 [in]-0,61 [in]
Driving Unit		
Type	Surface Unit	Downhole Motor
Power Source	Solar/Wind (in Development) Propane or Field Gas Electricity	Electric Line: 460 Volt/3 phase
Power Electric Motor	0,5-25 [HP]	
Power Gas Motor	15-40 [HP]	
Heat Trace	Downhole system is self-cooling and self-lubricating, can be ran in pumped-off mode for about 8 hours. Surface: on flow lines, well head and fuel gas lines-->heat exchange system	System is sensitive on overheating; Motor should be placed in fluid flow for cooling

Table 29: Comparison of HSP and HDESP I

Comparison of other properties		
Deviated Wells	almost every deviation possible	vertical or slightly deviated wells
Sand/Solid Handling	Self-flushing Sand screen: 1.3 [m] length; 1,5 [in] OD handles solids <0.01 [in]	according to manifacturer: high levels of solids can be pumped; up to 2% fines; nevertheless maintain higher velocities than 1 [ft/sec] is sensefull; found something else which told: moderate solids
Gas Lock	should not be, but is possible	Never occured under field conditions @ pump off state. Very unlikely
Pump-Off State	not more than 8 hours, determined by monitoring gauge of the oil flow leaving surface pump	Can especially make problems with overheating; pumpoff control via surface control
Exposure to Well Conditions	No rods or other sensitive parts are exposed; just the piston has contact to the pumped medium; no contact with solids because of sand filter.	Very unsensitive to chemicals, high salt contents or H_2S/CO_2; no moving parts are exposed to the pumped fluid. No sand filter: Therefore interference with solids are possible
Setting Time	can be installed and running in half a day;	it is easy to set
Rate Handling	very easy by joystick; flow of hydraulic oil dictates the cycles; frequency is controlled by pumping speed.	fixed rate
Footprint	very small, surface unit has the dimensions 3.3 [ft]x 8.2[ft]	small surface installations; allows smaller well locations
Noise	55 decibels @ 10m	nearly eliminated
Meantime Between Failure	Very Different	Is compared to ESPs or Beam Pumps according to field studies quite good. Therefore money savings
Other Advantages	can be combined with a gas compressor; portable system exists; no problem with wellhead/surface line freezing in winter	higher drawdown, but no cavitation problems
Other Disadvantage	production volumes are dependent on depth	Should not be operated in Ratholes

Table 30: Comparison of HSP and HDESP II

Outlook: New Developments

The recherché for this thesis showed that in the last few years many new artificial lift systems based on hydraulic principles have been patented and developed. One contribution to this new developments comes from the Mining University Leoben.

The system has been published in 2011 and shall give an outlook in which direction new developments can lead. All further remarks in this chapter refer to Reference 120[74].

New Hydraulic Pump System

Main Principle

Components

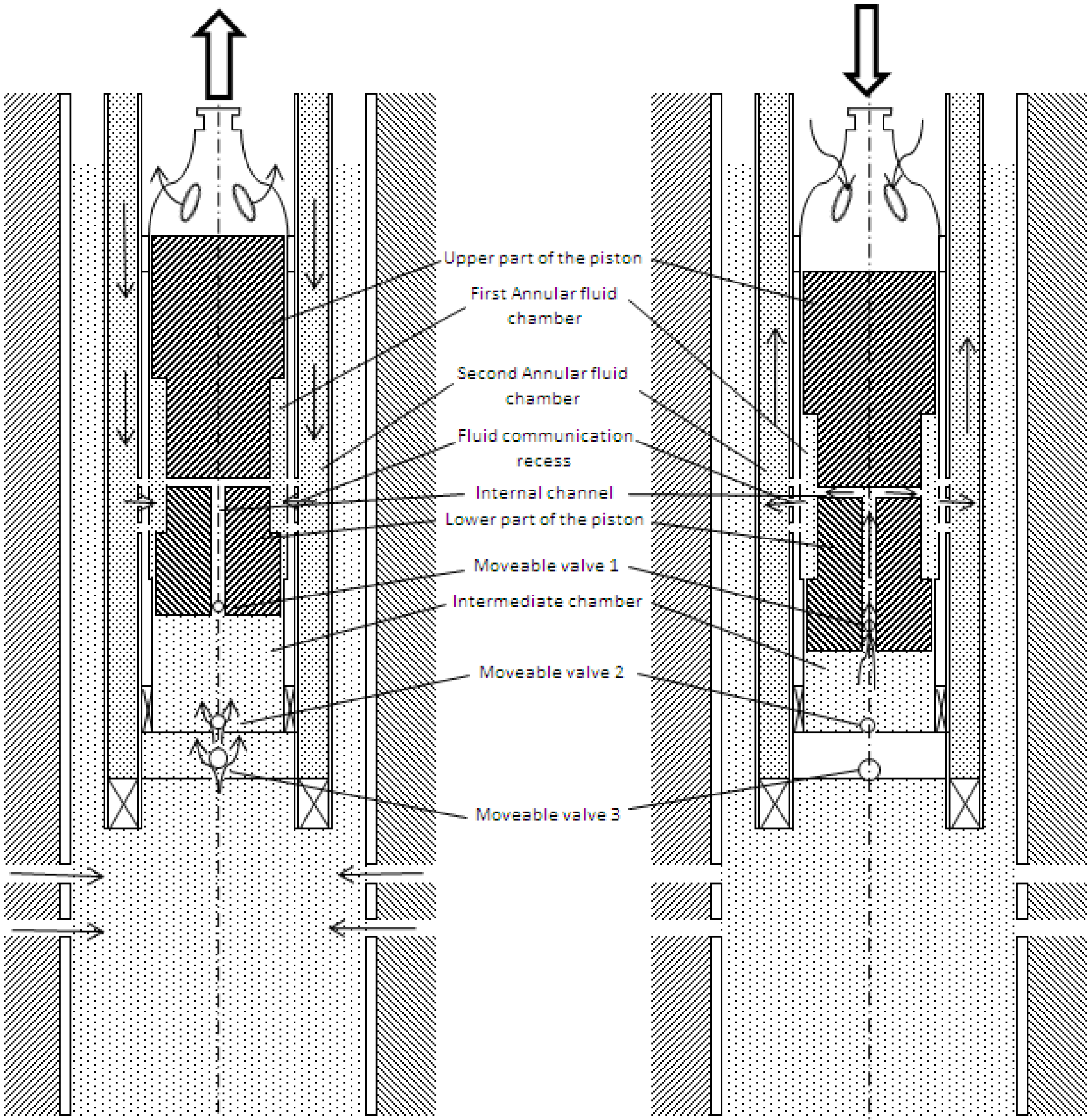


Figure 52: Components and Working Principle of a New Hydraulic Pump System

The new hydraulic pump system is mounted to a concentric tubing completion. The outer tubing string reaches slightly deeper into the well than the inner one. A retrievable valve (moveable valve 3) seals the lower bottom of the outer tubing and prevents communication of the hydraulic fluid with casing and the perforations.

At the lower end of the inner tubing a barrel is installed, with another valve (moveable valve 2) at the lower end, which prevents uncontrolled fluid communication. As shown in the figure above the lower end of the piston and the moveable valve 2 form an intermediate fluid chamber during the upwards movement of the piston.

All three valves shown in the figure above are ball valves. The diameter of the valves increases with increasing distance to the first annular fluid chamber.

Within the barrel a reciprocating piston is installed, which is consists of a lower part, an upper part and an intermediate part, which comprises a smaller diameter than the upper and the lower part. The lower part of the piston shows a bore, which is used as an internal channel and comprises a moveable valve 1. The whole internal channel is formed in T-shape and provides a fluid flow path between the intermediate fluid chamber and the first annular fluid chamber. The upper and lower parts of the piston form a fluid tight seal to the pump barrel.

The inner tubing and the small-diameter middle part of the piston form the first annular fluid chamber. The second annular fluid chamber is formed by the inner and outer tubing. Perforations at the height of the first annular fluid chamber offer a flow path between the first and second annular fluid chamber.

The inner tubing and the second annular fluid chamber are connected to a hydraulic pump at the surface. The inner tubing contains a hydraulic fluid, while during the operation of the pump the second annular fluid chamber contains a mixture of hydraulic fluid and production fluid.

Working Principle

As mentioned above the inner tubing and the second annular fluid chamber are connected to a hydraulic pump at the surface. To create the upstroke movement of the reciprocating piston, the second annular fluid chamber is pressurized. The pressurized fluid enters the first annular fluid chamber through the perforations (fluid communication recess). The increasing pressure forces the piston to move upwards.

During the upstroke, the moveable valve 1 closes. The emerging underpressure within the intermediate fluid chamber forces the valves 2 and 3 to open and the production fluid enters the intermediate fluid chamber.

To force the piston into downwards movement, the pressure is taken from the second annular fluid chamber and the inner tubing is pressurized. The pressure within the inner tubing forces the piston to move down again. Hereby the moveable valve 1 opens while valve 2 and 3 close and the fluid from the intermediate chamber can flow through the internal channel within the piston into the first annular fluid chamber.

The production fluid therefore is produced through the second annular fluid chamber where it mixes with the hydraulic fluid. Other than to other sucker rod pumps, the downstroke of the reciprocating piston is the producing stroke.

Installation and De Installation

At first the moveable valve 3, which is a pullable standing valve is set at the lower end of the outer concentric tubing. Afterwards the pump itself is circulated into place.

For de-installation first the second annular fluid chamber is over-pressured to circulate the pump out. Then the valve can be pulled by wire or rope.

Advantages

Energy saving U-tube effect

During the upstroke the fluid which has been pressed into the second annular fluid chamber at the downstroke will now –according to the physical concept of the U-tube effect - flow back into the first annular fluid chamber and therefore assist the upstroke movement. The hydrostatic pressure from the second annular fluid chamber therefore causes the U-tube effect. The second annular fluid chamber acts as potential energy storage and the back flow of the fluid into the first annular fluid chamber provides an additional lifting force for the upstroke.

This allows a very energy-efficient pump operation.

Application in highly deviated wells

Because of the rodless design of the pump an application in highly deviated wells is possible. When producing a highly deviated well with a conventional sucker rod pump, the rod string tends to shear along the tubing wall in the deviated section, causing rod and tubing wear and making the application of a rod rotator necessary. The rodless design of this pump prevents this problem.

No contact between hydraulic fluid and formation

The separately retrieveable moveable valve 3 provides the possibility to circulate the pump out by over-pressuring the second annular fluid chamber. Due to the moveable valve 3 this can be done without a direct contact between the perforations and the hydraulic fluid, which prevents a possible (negative) influence (additional skin) on the pay zone.

Ease of installation

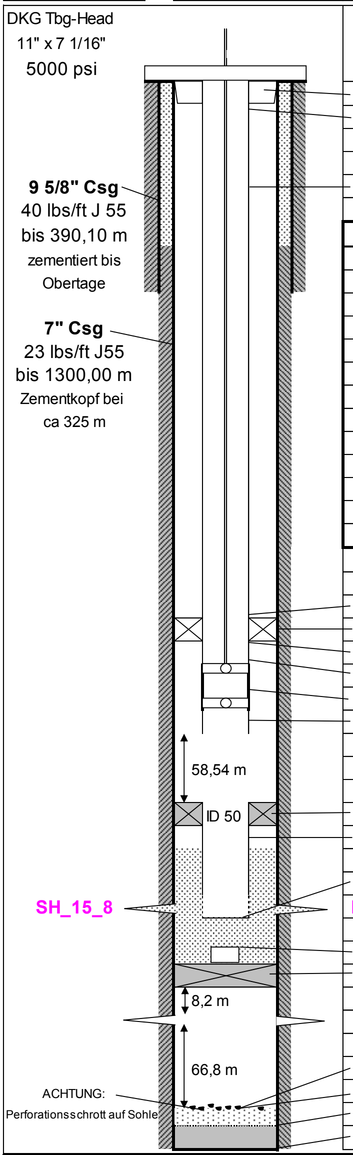
The system is easily installed by circulating the pump down. Therefore no work-over rig is necessary to install the pump, which decreases installation costs and increases installation safety.

No external wires are required during the operation, and therefore no additional working steps during installation are necessary.

Oil Well Completion

KOMPLETTIERUNG

Datum		
20 03 2012	HZ/HH 5,2/366	theor. Förderung 70,4 m³ / d



E I N B A U D A T E N	Länge [m]	eingebaut bis [m]
2 7/8" x 7 1/16" Tbg-Hänger geteilt DGK mit DN Tbg - Head Oberkante = Ackersohle	0.44	0.44
109 Stk 2 7/8" EU-Tbg	1038.94	1039.38

Stk.	PUMPGESTÄNGELISTE	Länge	bis	PG-Auslastung nach RODSTAR-D Servicefactor 0,9
1	1 1/4" Polierstange HJ gebr	7.45	6.08	
4	1" KST (2,4+1,2+0,55+0,65 m)	4.80	10.88	
31	1" x 2 7/8" 2EPA2 gebr	236.22	247.10	55 %
63	7/8" x 2 7/8" 2EPA2 gebr	480.06	727.16	61 %
20	3/4" x 2 7/8" 2EPA2 gebr	152.40	879.56	57 %
21	1" x 2 7/8" 2EPA2 gebr	160.02	1039.58	29 %
1	2 7/8" spiral rod guide + XO	0.43	1040.01	30%
1	7/8" Kolbensingle glatt NEU	7.62	1047.63	
1	2 1/4" Stahlkolben	1.23	1048.86	Annahme
1	2 1/4" Fußventil	0.41	1049.27	dyn Spiegel
1	1 1/2" Pumpenliner	0.58	1049.85	bei 750 m

	Länge [m]	eingebaut bis [m]
XO 3 1/2" EUZ x 2 7/8" EUM	0.57	1039.95
7" LRTA-Anker 75 A mit 8 Scherstifte (18 t)	1.63	1041.58
XO 2 7/8" EUZ x 3 1/2" EUM	0.56	1042.14
2 7/8" EU Kurzstück	0.76	1042.90
2 7/8" x 2 1/4" x 20' TH-Pumpe	6.37	1049.27
2 7/8" EU Kurzstück	0.60	1049.87
7" SM 1 Packer (fangen mit Gewindefangstück) bei **1108,41 m**	1.16	1109.57
2 7/8" NU Niro Kiesfilter SW 0,2 mm	38,31 m	
eingebaut am 28 04 2011		
Kiesfilterschuh		1146.72
Perforation: SH_15_8 im Bereich von 1139,0 - 1145,0 m = 6,0 m		
am 29 03 2011 mit 4 1/2" TCP, 9 spf, 4512 PJ, gesamt 178 Schuss		
Top 2 7/8" Trennstück Unterteil = **1167,99 m**		
7" Lok-Set-Packer mit Zirkulierstopfen und 2 7/8" Trennstück Unterteil	2.01	1170.00
Sohle von 1190 m bis 1249 m freizirkuliert - Sand (SBH am 23 09 2010)		
Sohle bei 1250,4 m (weich aufgestanden Schlumberger am 06 092010)		
RV bei 1261,93 m		
Endteufe am 25 07 2010 bei 1300 m MD (~ 1253 m TVD)		

Inventurnummern		Abstreiffeistigkeit	3 1/2" EU-Tbg; 9,3 lbs/ft; J55 roh; neu	64,6 t
Pumpe	DUT 483	100%	2 7/8" EU-Tbg; 6,5 lbs/ft; J55 roh; neu	45,0 t
Anker	2144	max. empfohlene	Pumpgestänge 3/4" 12 to	1" 22 to
Packer		Belastung	(neuwertig) 7/8" 17 to	1 1/8" 29 to

Ankerabsetzdaten:
4 t Zugspannung; Setzweg 0,35 m; 8 pins ca 18 t
Setzweg:
Ankerlösevorgang:
Strang hochziehen, langsam Zugspannung reduzieren und gleichzeitig 1/2 Umdrehung rechts drehen
Anmerkungen
Gesamtabweichung: 233,47 m (MD 1285,5 m, TVD 1240,33 m)
max Neigung: 28,44° bei 1101 m

Eingebautes Equipment

TUBING Dimension	Stk	kg	GESTÄNGE Dimension	Stk	kg
2 3/8"		0	**3/4"**	20	380
2 7/8"	109	9,701	**7/8"**	64	1,728
3 1/2"		0	**1"**	52	1,716
4 1/2"		0	**1 1/8"**		0
Summe	**109**	**9,701**	Summe	**136**	**3,824**

Table 31: Oil Well Completion – Sucker Rod String

Technical Data Comparison				
	conventional Sucker Rod Drive: Lufkin C-640D-365- 144		electro-hydraulic Sucker Rod Drive: Bosch Rexroth R7	
	SI	Oil Field Units	SI	Oil Field Units
Stroke length nom.	366 [cm]	144 [in]	366 [cm]	144 [in]
Stroke length max.	366 [cm]	144 [in]	366 [cm]	144 [in]
stroke length min.	267 [cm]	106 [in]	flexible	flexible
SPM (max.)	5.2	[spm]	7.5	[spm]
Polished Rod capacity	36,500 [lbs]		36,500 [lbs]	
theor. Production rate	70.4 [m³/d]	443 [bbl/d]	84.2 [m³/d]	530 [bbl/d]
real Production rate (efficiency factor η=0.8)	56.3 [m³/d]	354.4 [bbl/d]	67.4 [m³/d]	424 [bbl/d]

Table 32: Oil Well Completion – Technical Data Comparison between Lufkin Pump Jack and R7

Installation and Maintenance				
electro-hydraulic Sucker Rod Drive: Bosch Rexroth R7-365				
Installation				
	time	personnel	operator	manufacturer
Container (incl. Hydraulic aggregate and surface panel)	delivered as whole container, setting time ?		x	x
Frame and Cylinder	3 [hrs]	3		x
electrical connections	3 [hrs]	1	x	
hydraulic Connections				
steel lines	1.5 [d]	2		x
hydraulic hoses	0.5 [hrs]	2		x
Maintenance				
yearly maintenance (incl. Hydraulic oil and filter change)	8 [hrs]		x	
motor change (est. after 2.5 years)			x	

Table 33: Oil Well Completion – Installation and Maintenance Timetable

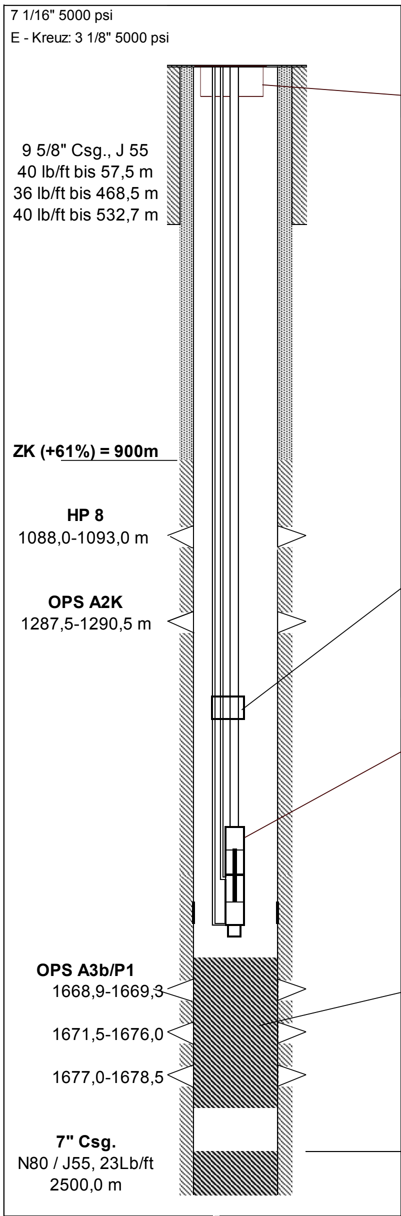
Cost Comparison Lufkin Pump Jack vs. Bosch Rexroth R7				
Gross Net Production GA-092	0.1	[t/h]		
Oil Price	500.0	[EUR/t]		
	Lufkin C-640D-365-144		Bosch Rexroth R7-365	
CAPEX	140,000.0	[EUR]	63,000.0	[EUR]
Installation Costs	15,000.0	[EUR]	350.0	[EUR]
Cylinder				
electrical connections			2,000.0	[EUR]
hydraulic connection (hoses)			1,000.0	[EUR]
Sum	155,000.0	[EUR]	66,350.0	[EUR]
OPEX				
yearly maintenance	N/A		1,000.0	[EUR]
hydraulic oil	N/A		500.0	[EUR]
production downtime	N/A		400.0	[EUR]
workover downhole pump	30,000.0	[EUR]	35,100.0	[EUR]
production downtime	2,400.0	[EUR]	2,700.00	[EUR]
pulley change	150.0	[EUR]	N/A	
production downtime	100.0	[EUR]	N/A	
electrical consumption	0.00628437	[kW/(m³*m)]	0.02228571	[kW/(m³*m)]

Table 34: Oil Well Completion – CAPEX and OPEX comparison

Tail End Gas Well Completion

Komplettierung

Datum: 27.03.2012 Ergänzungen:



EINBAUDATEN	Länge: [m]	eingebaut (bzw.Teufe) bis [m]
Tri-Coiled String Well Head	0,15	0,15
Dreifach Tubing Hanger	0,20	0,35
Triple-encapsulated CT-String (1.25"x1.0"x1.0")		
Lufkin HSP 5,6 [m]		
von 1590-1584,4 [m]		
7" Schiebemuffe		1453,00
Zementbrücke von 1600,0 bis 1732,0 m		
Zementsohle		2450,00

Table 35: Tail End Gas Well Completion

Technical Data				
Subsurface Pump				
OD Pump			3,75	[in]
Length			5,59	[m]
Weight			114	[kg]
Flow Range			0.1-30	[m³/d]
Energy Efficiency			0,13	[kW/bbl]
Tubing				
Production String			1,25	[in]
Hydraulic Strings			1	[in]
Surface Unit				
Dimensions			2.5x1.0x1.0	[m]
Sand Screen				
length			1,3	[m]
OD			1,5	[in]
slot size			10 spiral slots, 0.01	[in]

Table 36: Tail End Gas Well Completion –Technical Data Comparison

Installation and Maintenance		
Rig up	2,5	[hrs]
RIH	depth dependent	
coiled tubing	2	[hrs]
conventional tubing	depends on depth	
hydraulic connections, tubing/pipeline connection	1	[hrs]
Maintenance		
daily	Inspection of	oil temperature (engine and hydraulic oil)
		rpm (between
		visual inspection of hydraulic lines
		hydraulic oil filter gauge
every 2-3 weeks		change motor oil
monthly		check engine coolant
every 3 months		check hydraulic oil in terms of dirt, colour change etc.
every 6 months		change hydraulic oil in surface equipment

Table 37: Tail End Gas Well Completion – Maintenance Schedule

Cost Comparison				
for 1590 m setting depth and a max. production of 11.0 m³/d [69 bbl/d], real gas production 950 m³/d, real fluid production 2.9 m³/d,				
	PCP		Lufkin HSP	
CAPEX	35.000,0	[EUR]	~76,000	[EUR]
Installation Cost	100.000,0	[EUR]	N/A	
OPEX				
Daily check			80	[EUR/d]
	0	[EUR/y]	29.200	[EUR/y]

Table 38: Tail End Gas Well Completion – CAPEX and OPEX comparison

Conclusion

The above presented different hydraulic artificial lift methods adress different problems. The hydraulic drives for sucker rod pumps, the Bosch Rexroth R7, the Ecoquip 9000 Hydraulic Pump Jack and the Subsurface Hydraulic Rod Pump primely are designed to be an alternative for conventional Pump Jacks. The HSP 3000 (Lufkin) and the HDESP (SmithLift) are designed for the de-watering of shale gas or coal bed methane wells.

The hydraulic sucker rod pump drives

Therefore all of them try to meet two “weak points” of the conventional Pump Jack Systems:

- The massive visibility and footprint of conventional Pump Jacks
- The inflexibility in adjusting conventional Pump Jack operation to meet changing production situations.

All three systems show a considerably reduced visibility and a definitly smaller footprint than conventional Pump Jacks, therefore offering a clear advantage if used in residential areas. But the reduced visibility comes along with a problem: Bosch Rexroth R7 shows a quite high level of noise during the normal operation mode and can only be applied in residential areas if additional noise protection is provided. The subsurface Hydraulic Rod Pump offers the lowest visibility.

Bosch Rexroth R7

Other than conventional Pump Jacks, the R7 as well as the Ecoquip 9000 offer the possibility to produce more strokes per minute (and therefore increase production) as well as to reduce the numbers of stroke per minute. Controls are very easy and can be at surface control panels, no pulley changes (as for the conventional Pump Jacks) are required. Also the velocity of up- and downstroke can be adjusted seperatly to each other as well as the stroke length. This offers a high amount of flexibility in production. Strong producing wells can be produced faster at same pump size. The R7 is currently installed in Landau on a well with inflow restricitions. The system offers the possibility to reduce the number of strokes just by some computer inputs, therefore can be operated with a very low number of strokes per minute. This is currently done by Wintershall, but the well’s inflow is too low to achieve a good pump filling. One possibility would be to slow down the upstroke movement, giving more time for the pump to refill. This may be a solution for low producers, which are often operated as time-runners. A time-runner is a pump which operates just a few hours, then shuts down and after a pre-set time is started again. Due to the fact that the start of a pump consumes a high amount of power and solids settle down on the valves every time the pump stops – a massive problem for wells with a high amount of solid production –causing problems when starting the pump, a hydraulic pump may be a good alternative here.

Bosch Rexroth has not finished the testing operation of R7 in Landau yet, therefore it is hard to tell if the increase in production which the R7 provides is large enough to economically overcome the higher energy consumption.

According to the manufacturer the use of a rod rotator is not possible for the R7, a fact that definitly limits the application possibility of this system to vertical or just slightly deviated wells.

One problem here is the fact, that Bosch Rexroth doesn't have much experience in the E&P - Business and therefore has problems to meet the necessities of E&P-companies. Therefore the R7 shows some "teething problems" which have to be overcome. One of the most obvious one is the material of the cylinder rod, which also acts as polished rod. Another one is the fact that no rod rotator exists for the R7. The application of a mechanical rod rotator may not be possible – if an electric rod rotator is not possible has to be reviewed.

Ecoquip 9000 Hydraulic Pump Jack

Other than to Bosch Rexroth, the application of a rod rotator is possible at Ecoquip 9000 Hydraulic Pump Jack. The system provides mainly the same advantages as the Bosch Rexroth R7. Due to the fact that it works with a conventional polished rod and stuffing box some of the problems the R7 definitly has, cannot come up.

The manufacturer is a small company based in Canada and it is difficult to communicate with Ecoquip. During the last months the only information which has been provided by Ecoquip where more or less the same as published in the advertising brochure, making it nearly impossible to give an educated overview especially over the disadvantages of this system. Nevertheless one weak point is the nitrogen-filled energy storage sphere. Bosch Rexroth already tried this type of potential energy storage at the predecessor system of R7. The system needed much maintenance, the nitrogen had to be refilled all 6-8 weeks. The efficiency declined drastically after 50,000 cycles. Also the correct operation of the nitrogen-filled sphere was very temperature-dependent.

HRPI Subsurface Hydraulic Rod Pump

Especially for big producer wells in residential areas the subsurface Hydraulic Rod Pump may be an attractive alternative to conventional systems. Other than to conventional sucker rod pumps, the system provides longer stroke lengths, but less strokes per minute which can significantly increase the lifetime of sucker rods and downhole valves. The hydraulic cylinder which drives the pump is installed below the surface inside the tubing, therefore showing a significantly reduced visibility.

Long stroke pumps show a significantly better behavior in dealing with high gas/oil ratios. Also the long strokes increases the filling time for the downhole pump, which may be a good combination for an application in de-watering gas wells. According to the manufacturer about 30% of their whole business is de-watering gas wells, thereby using largest possible downhole pump.

In difference to the R7 and Ecoquip 9000 which both show a decreased energy efficiency in comparison to mechanical Pump Jacks, the dual-well application possiblity of the subsurface Hydraulic Rod Pump increases the energy efficiency of this system significantly. Therefore an application at very dense drilling sites may be senseful.

The de-liquification systems

Lufkin HSP 3000

The HSP is an interesting artificial lift system for de-watering of gas wells as well as for the end-production phase of oil wells. It has small surface installations, which makes it applicable even in residential areas.The surface installations provide an integrated noise protection which is also an advantage when using it in residential areas.

Very interesting is also the maximum drawdown which can be achieved by using the HSP. The system provides a very low $NPSH_r$, which makes it possible to operate at very low reservoir pressures in the very tail end of production phase of a well. The system can also operate for some time in pump off mode without suffering immediate failure, so the fluid level within a well can be lowered to the absolute minimum, decreasing the backpressure on the producing formation and therefore avoiding liquid loading and even "dying" of the well. The system can be used in almost every position, so also strongly deviated wells can be produced by the HSP.

Another advantage is the ease of installation and de-installation especially if using the triple-encapsulated coiled tubing string. The system can be installed in half a day. Therefore it can also be used as portable artificial lift system [55], perhaps it may also be a possibility for well testing purposes. This is already done in some applications in Canada.

Rate and frequency can be set flexible and variable, so within the possible flow rate range the rate can be adjusted quickly depending on production conditions, therefore it may be an interesting system in wells with changing flow conditions.

The triple-encapsulated coiled tubing also is the key cost factor in CAPEX. Therefore an absolute CAPEX number cannot be given, it depends on the depth of the well. The deeper the well, the higher the CAPEX. OPEX include also maintenance, and here is the weak point of the HSP: frequent maintenance, hydraulic oil changes etc. are necessary.

Another disadvantage is seen: The pump is limited to a max. setting depth of around 2,500 m and the possible flow rates are strongly depending on depth. The system shows a rate of 25 m^3/d in 500 m setting depth, but in 1,500 m depth this is reduced to 12.0 m^3/d and in 2,500 m only 7.0 m^3/d flow rate are possible.

One more disadvantage is that Lufkin seems not to be very interested to introduce the HSP into the European Market.

Smith Lift HDESP

The Smith Lift Hydraulic Diaphragm Electric Submersible Pump is, especially compared to the HSP offered by Lufkin a just very limited usable de-watering system. It offers certain advantages, as low energy consumption, a very small footprint, low nois emissions and no open laying hydraulic high-pressure lines at the surface, also practically no maintenance is necessary due to its ESP-design. A quite high amount of solids and sand can be produces without increased failure probability, but the HSP works with an integrated sand screen which makes a use in high-sand producing wells also possible. Also CAPEX is only little lower than for the HSP, and the flexibility as well as the possible flow range and setting depth are very limited.

The system can only be used for depths down to 760 m and with basic surface installation only a pre-set flow rate is possible. This can be compensated with a variable frequency drive, but even then just slight modifications of the flow rate are possible. Basically the maximum achievable flow rate depends on depth and on the used internal pump. The system can only be used in wells with an deviation angle of max. 30°.

It can be conclused that the HDESP may be an interesting system for de-watering shallow, slightly deviated gas wells, but cannot be used in deeper or strongly deviated wells or wells with strongly changing flow conditions.

Smith Lift as well as Lufkin seems not to be interested to introduce the HDESP into the European Market.

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List of Abbreviations

Acronym	Explanation
API	American Petroleum Institute
ATEX	The ATEX directive consists of two EUdirectives describing what equipment and work environment is allowed in an environment with an explosiveatmosphere. ATEX derives its name from the French title of the 94/9/EC directive: *Appareils destinés à être utilisés en ATmosphères EXplosives*
Bcf	Billion cubic feet
BFPD	Barrel fluid per day
Ca.	*circa*, english: approximately
CAPEX	Capital expenditures
CBM	Coal Bed Methane
CO_2	Carbon Dioxide
CPJ	Conventional Pump Jack
CR	Compression Ratio
dBA	dBA, decibel A-weighting, an environmental noise measurement
e.g.	*exempli gratia*; English: for example
E&P	Exploration and Production
ESP	Electric Submersible Pump
etc.	*et cetera*; English: and so on
FBE	Fusion bonded epoxy, an epoxy based powder coating that is widely used to protect steel pipes
GLR	Gas Liquid Ratio
GPM	Gallons per minute
H/h	In Petroleum Production normally referring to depth in [ft] or [m]; also *head*…pressure converted to depth
HDESP	Hydraulic Diaphragm Electric Submersible Pump
HP	Horse Power
HPJ	Hydraulic Pump Jack
HRP	Hydraulic Rod Pump
HSE	Health, Safety and Environment
HSP	Hydraulic Submersible Pump
H_2S	Hydrogen Sulfide
i.a.	*inter alia;* English: amongst others
ID	Inner diameter
max.	maximal
MTBF	Mean time between failure
NEMA	National Electrical Manufacturers Association
NPSH	Net Positive Suction Head
$NPSH_a$	Net positive Suction Head, available
$NPSH_r$	Net Positive Suction Head, required

OD	Outer Diameter
OPEX	Operational Expenditures
PCP	Progressive Cavity Pump
PLC	Programmable Logic Controller
PPRL	Peak polished rod load
RIH	Running Into Hole
rpm	Rotations per minute
SPM	Strokes per minute
SS	Stainless Steel
US	United States (of Amercia)
VAC	Voltage in alternating current
3-D	Three-dimensional

All other units, formula signs, etc. follow international norms, especially DIN.

Appendix

Comparison of Conventional Artificial Lift Systems

Comparison of conventional artificial lift systems						
	Progressive Cavity Pumps		Electric Submersible Pumps		Jet Pump	
Units	basic	max.	basic	max.	basic	max.
Part of WW Production	N/A		18%		1%	
Usage	N/A		An excellent high rate artificial lift system. Best suited for <200°F and > 159 m³ rates. Most often used on high watercut wells		Good for higher volume wells requiring flexible operation; wide depth range, high temperature, high corrosion, high GOR, significant sand production	
Pump						
Pump Speed	100-1000 rpm		N/A		N/A	
Flow Rate	0.8 - 350 m³/d	715 m³/d	30-3,200 m³/d	4,700 m³/d	50-160 m³/d	3,100 m³/d
			The full range of production rates can be handled. When unconstrained an ESP can be designed to produce the full well potential to the surface (AOF), thus achieving higher flow rates than the gas lift		The full range of production rates can be handled. Less than 8 m³ up to 2,385 m³. AOF production cannot be achieved.	
Volume high lift capabilities	limited because of throughput rate, can be increased by using a higher lobe ratio and by hollow rods		excellent, limited by needed HP and can be restricted by casing size. Tendom motors can be used to increase HP but also increase operating costs.		Excellent, up to 2,385 m³ with adequate flowing bottom hole pressure, tubular size and HP.	
Volume low lift capabilities	basically good, but low volumetric efficiencies in high-gas environments		generally poor, lower efficiencies and high operating costs <64 bar		Fair, >31.8 m³ from 1,220 m	
Produced Media						

Gas Liquid Ratio	good	very sensitive; from 10%: problem; up to 45%: centrifugal gas handlers; up to 75%: axial flow technology;	good; target design is 1000 GLR. Not recommended for GOR greater than 2000, this may reduce the efficiency but helps lift. Vent free gas if possible. Production of free gas through the pump may reduce the ability to handle fluids.
Gas handling capability	can even be used for de-watering gas wells	N/A	good/fair; may require suitable downhole gas separator below pump intake. Free gas reduces efficiency but helps lift. Vent free gas if possible. Use a gas anchor
Water Cut	not sensitive to high water cut; good for pumping emulsions	100% water possible	100% Water possible, but may increase OPEX
Fluid Gravity	<40° API	>10°API	>8 °API to 45°API
High viscosity fluid handling capability	PCPs are an artificial lift method for viscous fluids (heavy oil application) as well as for light oils (40°API)	Fair, limited to about 200 cp	good to excellent; >6° API production with <800 cp possible, power oil of >24°API and <50 cp (water power fluid reduces friction loss)
Sand Production	solids in suspension: very good suited; Pumps oil and water with solids	just moderately tolerant; special running procedures and pump placement techniques are required	fair to poor; Operating with 3 % sand. Fresh water treatment for salt buld up possible.
H2S, CO2/ Corrosion handling	fair	Fair; Run life will be shortened in a more aggressive envirionment. Spechial metallurgy and elastomers will be required leading to more costly equipment	excellent; using special metallurgy and chemical treatment. Chemical in the power fluid can treat the tubular for corrosion. Inhibitor fluid mixes with produces fluid at entry of jet pump throat.

Scale Handling capability	N/A	If well is prone to scale, paraffin or asphaltene deposits, this will occur in the pump area and cause a large pressure drop. Leads to pump inefficiency, increased wear and tear and eventually to failure. Chemical treatment is required to prevent formation of theses contaminations.	Scale could build up at intake and nozzle over time but can be treated.
Treatment (Scale and corrosion inhibitor)		Materials design will need to be modified to ensure continued service of the ESP after treatment	Corrosion/scale ability is good. Inhibitor with power fluid mixes with produces fluid at entry of jet pump throat. Batch treat down annulus feasible.
Pump Abilities			
Pump Efficiency	Weatherford: 50-75 % high system efficiency comes with low power consumption	Weatherford: 35-60 % Good for high rate wells, but decrease significantly for <159 m³. Typically about 50 % for high rate wells but for < 159 m³, efficiency typically <40%	10 - 25 % Fair to poor, max. efficiency for ideal case is 30% thus power fluid at 2-3 times the produceds fluid rate is requried. Ifluenced by power fluid plus prodcution gradient.
Run Life/MTBF	2-5 years	differs with depth, average two years.	N/A
Well Intervention	N/A	Change out of total completion required for ESP failure.	A free jet pump can be circulated to the surace without pulling the tubing or it can be retrieved by wireline
Setting Method	Workover or Pulling rig	jointed, tubing deployed; cable-deployed; coiled tubing-deployed; Workover or Pulling Rig	Hydraulic or wireline
Flexibility	high operational flexibility	Poor for fixed speed. Requires careful design; VSD provides better flexibility.	Good to excellent; power fluid rates and pressure adjusts the production rate and lift capacity from no-flow to full design capacity of installed pump; selection of threat and nozzle sizes extend range of volume and capacity.

Reliability	N/A		Varies, excellent for ideal lift cases but poor for problem areas. System is very sensitive to operating temperatures and electrical malfunctions.		Good with proper throat and nozzle sizing for operating conditions. Must avoid operating in cavitation range of jet pump throat, related to pump intake pressure. More problems if pressure >276 bar.	
eventual HSE Problems	N/A		Full workover could be required every two years (industry average), hence safety risk is higher than gas lift. Electrical fire risk is increased.		More risk of injection and production lines rupture	
Well Specifications						
Depth		normal PCP: 2,400 m	300-3,000 m	4,500 m	1,500-3,000 m	6,000 m
Dogleg severity	0-90° Landed Pump - <15°/100 ft Build angle		10°	up to 90° pump placment; max. <10° build angle for setting	0-20°,	90°; pump placement: <24°/100 ft
Temperature [°C]	limit for elastomer seals: 150; for electronics: 220 Weatherford max. op. T: 250		max. between 204-250		204	
Casing size limit and (7") and restrictions in tbg. Size	N/A		Casing size will limit use of large motors and pumps. ESP restricted to a maximum diameter of 5.4" with a maximum flow rate of 1,900 m³		Small casing size limits producing rate at acceptable pressure drop level. Jet pump is recommended for 7" casing.	
Flowing Bottom Hole Pressure	N/A		Achieving any FBHP is not a constraint with ESP, AOF can be achieved if the well and reservoir properties do not constrain the ESP design.		For range of 6.9 to 69 bar, typical design tagret is a minimum of 6.9 bar per 305 m of lift. Intake pressure should be >24 bar to 1,524 m with low GLR. For BHFP less than 6.9 bar, jet pump cannot deliver fluids to surface.	

Drawdown	N/A	Any drawdown can be achieved with a given ESP design, but well and reservoir constraints limit final drawdown.	Good drawdown but cannot completely deplete a well
Reservoir			
Bubble Point	N/A	Not recommended for high bubble point, as this will limit the maximum drawdown in the well due to the detrimental effects of free gas in the pump.	Not recommended for high bubble point. Recommended for low bubble point.
Reservoir pressure decline	N/A	Not recommended when there is significant pressure drop, the range of production rates that a particular ESP design can handle is limited. Variable frequency drives (VFD) allow some operational flexibility on matching the production rate to the ESP design.	Not recommended when there is significant pressure drop in the reservoir, the range of production rates that a particular jet pump design can handle is limited. A new jet pump design needs to be placed to get optimum lift for the well
Flow stability	not recommended for unstable flow, the system requires a constant fluid level above the pump	not recommended for unstable flow	Continuous and smooth flow of produced fluids
Total System Description			
	N/A	Fairly simple to design, but requires good rate data. System is not forgiving, requires excellent operating practices follow API and RPs in design, testing and operation. Each well is an individual procedure using a common electric system	Available computer design program for application design. Basic operating procedure for downhole pump and well site unit. Free pump easiliy restricted for on-site repair. Downhole jet often requires trial and error to arrive at best/optimum jet.
Economics			
CAPEX	35.000 [EUR]	$250.000,00	$17.000
	low CAPEX	High for power generation and cabling. Reletively low if electric power available. Costs increase as horsepower increases	Relatively low to moderate. Cost increases with higher horesepower. Wellhead equipment has low profile. Requires surface treating and high pressure pumping equipment.
Tubing	N/A	$80.000,00	N/A
Pump	N/A	$25.000,00	N/A

other Equipment	N/A	$141.000,00	N/A
OPEX			
	low maintenance and electricity costs	Moderate to high. Costly interventions are required to change out conventional ESP completion. Varies with high horsepower, high energy costs. High pulling costs result from short run life. Repair costs often high, but productivity and improved run life can offset these costs.	High power cost dure to horespower requirement to pump power fluid. Low pump maintenance cost with properly sized throat and nozzle for long rund life. No moving parts in pump, simple repair procedures.
Lifting Efficiency [kw/bbl/d]	N/A	0,022	0,042
Workover Cost	N/A	$2000/d	$2000/d
Wireline Cost	N/A		
Other Costs	N/A	$225/month	$2900/month

Comparison of conventional artificial lift systems							
	Gas Lift	Sucker Rod Pumps		Beam Gas Compressor		Rotaflex Long Stroke Pumping Units	
Units	max.	basic	max.	basic	max.	basic	max.
Part of WW Production		40%		N/A		N/A	
Usage	Good, flexible, high rate artificial lift system for wells with high bottomhole pressures. Most like a flowing well.	excellent , used on about 85% of USA artificial lift wells. The normal standard artificial lift method		N/A		N/A	
Pump							
Pump Speed	N/A	N/A		12 spm		N/A	
Flow Rate	max. 8,000 m^3/d	0.8-240 m^3/d	max. 1,000 m^3/d	up to max. 433.2 mcf/d; can improve Oil Production about 85%, max. 50 bbl/d			max. around 670 m: 635 m^3/d; max. around 3600 m: 63 m^3/d
	The full range of production rate can be handled. An AOF production rate cannot be achieved with gas lift because as much drawdown as for an ESP cannot be achieved.	Rate is dependent on setting depth. Feasible for low rates (15.89 m^3) and low GOR (<250). In general due to efficinecy, rod pump is not recommended as alift mechanism of choice on high production wells.					
Volume high lift capabilities	Excellent, restricted by tubing size and injection gas rate and depth.	Fair, restricted to shallow depths using large plungers. Max. rate about 636 m^3 from 305 m and 159 m^3 from 1,524 m.		N/A		N/A	
Volume low lift capabilities	Fair, limited by heading and slippage. Avoid unstable flow range. Typically lower limit is 32 m^3 for 2 " tubing and 112 m^2 for 3" tubing. Intermittent gas lift system is better for low volume.	excellent, most commonly used method for wells producing < 15.89 m^3		N/A		N/A	
Produced Media							

Gas Liquid Ratio	excellent; recommended for full ranges. Gas lift would be only expected to of benefit at higher GOR	fair to good; feasible for low rate and low GOR (<500 scf/stb). For range 500 to 2000, gassy wells usually have lower volumetric efficiency. Gas handling ability is rather poor if one has to pump >50% free gas. If the gas anchor or natural separation is used and free gas is venting, the volumentric efficiency can be significantly improved. Not recommended for GOR greater than 2000 scf/stb.	designed to prevent gas locking	N/A
Gas handling capability	excellent, produced gas reduces amount of injection gas.	Good if can vent and use gas anchor with proper designed pump. Poor if must pump (>50%) free gas.	N/A	N/A
Water Cut	High water cut may reduce efficiency due to heavier column of fluid to lighten. May not be able to lift well if reservoir pressure is low.	able to pump 100% of water	N/A	N/A
Fluid Gravity	No limitations, but preferable >15°API	>8°API	N/A	low Gravity Crude
High viscosity fluid handling capability	fair, few problems for ~16°API or below 20 cp viscosity. Excellent for high watercut lift even with high viscosity oil.	Good for up to <200 cp viscosity fluids and low rates (400 BFPD). Rod fill problem for high rates. Higher rates may require diluent to lower viscosity. For greater than 500 cp not recommended as pump efficiency will reduce.	N/A	N/A
Sand Production	good; recommended for all wells producing sand. Sand has little effect on ability to a gas lift well.	fair to good; high solids and sand production is troublesome for low oil viscosity (<10 cp). Improved performance can obtain for high-viscosity (>2000 BFPD) cases. May be able to handlw up to 0.1% sand with special pumps.	N/A	N/A
H2S, CO2/ Corrosion handling	good to excellent; capability of metallurgy and elastomers with the total completion is required. Inhibitor in the injection gas and batch	good to excellent if using corrosion-resistant materials in the construction of subsurface pumps.	good to excellent	N/A

	inhibiting down tubing feasible. Steps must be taken to avoid corrosion in injection gas lines.			
Scale Handling capability	Scale can form close to the operating gas lift valve due to the pressure drop at that location. This may lead to blockage of the gas lift valves and an inability to be able to retrieve them.	Good to excellent. Batch treating inhibitor down annulus feasible.	N/A	N/A
Treatment (Scale and corrosion inhibitor)	Recommended when any treatment is required. These treatments have little to no effect on a gas lifted system.	Corrosion and scale treatments easy to perform. Good batch treating inhibitor down annulus used frequently for both corrosion and scale control.	N/A	N/A
Pump Abilities				
Pump Efficiency	5- 30%; increases for wells that require small injection GLR's. Low for wells requiring high GLR's. typically between 20 and 30 %	Weatherford: 45-60 % excellent toal system efficiency. Typically 50-60%.	N/A	~60%
Run Life/MTBF	N/A	N/A	N/A	730 days
Well Intervention	For gas lift valve changeouts slick line intervention >5 years. For remedial work as required with the ability to perform through tubing workovers.	Workover or pulling rig. Run time efficiency is greater than 90% if good operating practices are followed and if corrosion, wax, asphaltenes, solids etc. are controlled.	N/A	N/A

Setting Method	wireline or workover rig	Workover or pulling rig		additional device for Beam Pumps, mounted to the well head and der Walking Beam		N/A	
Flexibility	Excellent, gas injection rate varied to change rates. Tubing needs to be sized correctly.	Excellent, can control production rate.		N/A		N/A	
Reliability	Excellent if compression system properly designed and maintained.	Excellent; run time efficiency >95% if good rod pumping practices followed.		N/A		N/A	
eventual HSE Problems	Safety risk is low. More risk of blow out and gas fire with high-pressure gas lines	Workovers to change out rod string could be required every 1 1/2 years. If it is a highly deviated well, frequent workovers could be required to fix broken rod string as frequent as once every 6-8 months.		N/A		N/A	
Well Specifications							
Depth	4,500 m	30-3,350 m	4880 m	N/A	N/A		3600 m
Dogleg severity	70°	0-20° Landed Pump,	90°; <15°/100 ft	N/A (as Sucker Rod)		possible up to horizontal	
Temperature [°C]		40-180		N/A (surface installation!)		high	
Casing size limit and (7") and restrictions in tbg. Size	Production tubing restricted to 4" tubing when installing side pocket mandrels.	Problems only if high rate wells requiring large plunger pumps. Small casing sizes (4.5"&5.5") may limit free gas separation. There is a limitation of downhole pump design in small diameter casing.		N/A		N/A	

Flowing Bottom Hole Pressure	If the FBHP is greater than 69 psi, the efficiency of the gas lift determines the achievable FBHP. A gas lifted well normally works with FBHP in this range. For ranges from 6.9 to 69 bar FBHP, gas lift can work in the upper end of this range for low reservoir pressure and productivity wells, however there needs to be enough reservoir energy to deliver the produced fluids to the surface. Less than 6.9 bar FBHP gas lift cannot deliver fluids to the surface.	The pump depth and the dynamic head restrict achieving a low FBHP. The excellent result can be obtained at intake pressure less than 1.72 bar providing adequate displacement and gas venting, typically about 3.4 to 6.8 bar FBHP	N/A	N/A
Drawdown	Achievable drawdown is limited by ability to lighten head of fluid above gas lift point. AOF can never be achieved.	The pump depth and the dynamic head limit achieveable drawdown.	N/A	N/A
Reservoir				
Bubble Point	Recommended for all bubble points. Gas lift not dependent on the bubble point pressure hence is suitable for any ranges.	Not highly recommended for high bubble point. Recommended for low bubble point.	N/A	N/A
Reservoir pressure decline	Recommended as the flexibilty of gas lift allows one installation to deal with falling pressure and production rates.	If there is no pressure support from the reservoir, production rate will decline and the well will be pumped-off.	N/A	N/A
Flow stability	Gas lift is able to handle all types of flow regimes.	not recommended for unstable flow.	N/A	N/A

Total System Description				
	An adequant volume, high pressure, dry, non-corrosive and clean gas supply source is needed throughout the entire life. Good data needed for valve design and spacing. API space and design/operating RP's should be followed.	straight foreward and basic procedures to design, install and operate following API and RP's. Each well is an individual system.	N/A	N/A
Economics				
CAPEX		€ 15,000-20,000	N/A	N/A
	Well gas lift equipment cost low, but compression cost and gas distribution system may be high. Central compression system reduces overall costs per well.	Low to moderate. Cost increase with depth and larger surface units.	N/A	N/A
Tubing		$61.000	N/A	N/A
Pump		$4.600	N/A	N/A
other Equipment	€ 15.240,00		N/A	N/A
OPEX				Servicing $45,000
	Low. Gas lift systems have a very low OPEX due to the downhole reliability. Well cost low, compression costs vary depending on fuel cost and compressor maintenance.	Low for shallow to medium depth (<213 m) and low production (< 63.6 m³). Units easily changed to other wells (re-use) with minimum cost.	N/A	N/A

Lifting Efficiency [kw/bbl/d]		$/bbp/month: $0.183/$2776	N/A	Power Costs/Month: $1,300 bzw. $/BBP/Month: $0.132/$2030
Workover Cost	$2000/d	N/A	N/A	N/A
Wireline Cost	$2000/d	N/A	N/A	N/A
Other Costs	$3000/month	N/A	N/A	N/A

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Rotaflex Presentation

SPE 52157, Table 12

SPE 52157, Table 8