SPE 48933

Artificial Lift Design for the Deepwater Gulf of Mexico

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This paper was prepared for presentation at the 1998 SPE Annual Technical Conference and Exhibition held in New Orleans, Louisiana, 27–30 September 1998.

Abstract

Artificial lift could significantly increase ultimate recovery from deepwater Gulf of Mexico (GOM) reservoirs, but the extreme application will present unique challenges to conventional artificial lift designs. This paper presents an exploration of feasibility and operability issues for both gaslift and Electric Submersible Pump (ESP) usage in direct vertical access wells in the deepwater GOM.

System and equipment considerations for gaslift and ESP design specific to the typical deepwater GOM application are discussed. Either system will work in this application, but they will both push current technology to the limit. The incremental recovery associated with either system is shown to be largely a function of the producing gas-liquid ratio.

A description of the creation and interpretation of outflow curves for the two types of artificial lift is also included. Outflow curves are an important element in the simulation of well deliverability and reservoir performance over time. Proper use of these curves and an understanding of the curve limits are necessary to perform a valid simulation.

Introduction

Deepwater Gulf of Mexico (GOM) production projects are characterized by high reservoir pressures and good permeability-thickness products, leading to very high rate wells, initially. Typical reservoirs also have moderate to high GOR's (600 to 3000+ scf/bbl), which provide natural lifting of fluids until reservoir pressures decline. Artificial lift may become necessary when reservoir energy is no longer sufficient to produce fluids to the host facility.

Artificial lift in producing applications in deepwater may benefit certain projects by maintaining adequate production rates as reservoir pressures decline, and by reducing abandonment pressure to increase ultimate recovery. Economics of artificial lift systems will be dictated primarily by reliability, production benefit, and operating range (intake pressure and well rate).

All artificial lift methods work by adding energy to the flowing stream in the wellbore. In gaslift, gas is injected into the tubing as deep as possible to aerate the fluids above the injection point. This lightens the fluid column, which lowers bottomhole flowing pressure and increases production. ESP adds energy by increasing pressure in the tubing through an electrically driven pump.

Artificial lift may therefore be applicable where reservoir energy is insufficient in itself to surface fluids at acceptable rates. Artificial lift will provide no benefit when reservoir pressures stay high enough to surface fluids at adequate rates, or when GOR's are so high that the injection of additional gas just increases friction. Since energy must be added to the system, it does not make sense to produce into high tubing pressures in any artificial lift scenario. Artificial lift will also not help early in the well life when the flow is already outflow-limited.

With different geometries, reservoir fluids, and depletion schemes on each project it would be impractical to present a general guideline on applicability of artificial lift for the deepwater GOM. Specific designs can be performed easily for any project where artificial lift might be beneficial, and, if warranted, lift curves created for simulation of production rates over time.

Electric Submergible Pumps

Electric submergible pumps (ESPs) are multistage centrifugal pumps driven by an electric motor. The pump and motor are normally suspended from the production tubing, with the motor positioned below the pump, and the pump discharging directly into the production tubing. Power is supplied to the motor via a three-conductor cable, which is run down to the motor from surface through the tubing/casing annulus.

In a centrifugal pump, the velocity imparted to the fluid by the rotating impeller is converted into pressure energy by the diffuser. Each impeller / diffuser set is called a "stage". In a multi-stage pump, the discharge of one stage is the input of the next, so that higher heads can be achieved than would be possible with a single impeller. Obviously, the mass flow rate through each stage in a multi-stage pump is the same.

Variable speed drives (VSD's) change the frequency of the power supplied to the motor, thus changing the pump speed and operating envelope according to the affinity laws. Since shaft horsepower and motor rating are linearly proportional to frequency, smaller pumps and motors run at higher frequency can give equivalent performance to larger equipment at line frequency.

Component and design considerations for the Deepwater GOM. ESP's are most commonly used in the oil field to produce high volume, high water cut, moderate depth wells. Distinguishing characteristics of deepwater GOM developments with respect to ESP are high rate, low water cut, moderate to high GOR, and deep reservoirs. Casing size, gas volume fraction (GVF) at the pump intake, total rate through the pump, and the power system will therefore control ESP design in deepwater.

ESP's generally have a narrow design range with respect to volumetric rate and total dynamic head (lift). Due to changing inflow conditions over time, most ESP's in deepwater would be operated on VSD's. Even then, several changeouts would probably be necessary to resize the pumps and motors over the life of any given well.

To provide adequate rates, ESP's in the deepwater would generally need to have 540 series (5.40" o.d.) motors and 513 series (5.13" o.d.) pumps. The smallest casing this equipment can be run in is 7", 32#, which still creates clearance issues. The smallest clearances will occur where the power cable runs past other equipment like the SCSSV or sub-mudline tubing hangers.

Gas handling. ESP's have historically been limited by the amount of free gas that could be tolerated before gas-locking would occur. At the very least, an ESP will suffer head degradation and low efficiency when high GLR fluids are being pumped. Free gas in large enough quantities will cause a pump to "gas lock", where the bubbles between stages become continuous and the pump no longer generates head. The smaller flow pumps with radial stages have been known to handle 10 to 15% free gas by volume (GVF), and the larger flow pumps with mixed flow stages can tolerate 20 to 25% GVF, at pressures less than 500 psi. At higher intake pressures, more gas can be handled.

GVF is a function of pump intake pressure (PIP), and is based on bubble point and GOR. Since the PIP and pump depth also determine maximum reservoir drawdown, limiting GVF will limit production. However, there are several ways to reduce the gas volume at the pump intake without limiting production, and also various ways to increase the gas handling capability of the pump itself. Still, in most gassy conditions, the pump must be set very deep in the well to limit GVF.

Limiting GVF at the pump intake may require some form of gas separation at the pump intake, by either active or passive means. The most common active method of separating gas is to use a rotary gas separator (RGS) intake. An RGS is a centrifugal device that throws the fluids to the outside of a chamber and diverts them to the base of the pump, while the gas is vented up the casing through crossover ports in the RGS. The RGS is mounted immediately below the pump, and serves as the intake for the pump. GVF is shown in Figure 1 as a function of fluid pressure below the bubble point. The effect of 70% gas separation is shown as the ability to achieve a lower intake pressure before the GVF limit is reached.

Producing gas up the annulus requires a packer above the pump, with a vent tube and associated annular SCSSV. Ironically, separating gas at the pump intake reduces the "gaslift effect" in the tubing and increases pump outlet head requirement even while the volumetric rate through the pump decreases. The additional valve at the packer and the requirement to produce live gas up the casing annulus may also present other reliability or operability concerns.

Other methods that limit free gas at the pump intake include running rotary gas separators in tandem, passive separation using shrouds, and recirculation systems. Higher GVF's can be handled in some conditions by using "tapered" pumps or certain proprietary solutions from the pump vendors. In waterflood applications, keeping away from the imposed free gas limit at the intake is easier, because reservoir pressure is maintained near the bubble point and GLR decreases with increasing watercut.

Pump rate. In any application other than pumping pure water, it is important to keep in mind that "volumetric rate" through a pump stage is calculated at the pressure conditions at that stage. A 1000 B/D oil rate at the surface might correspond to a 1300 B/D rate at the pump intake, or as much as 3 – 4000 B/D if free gas is present. The largest recommended flowrate (at 60 Hz) for 513 series pumps is about 12,000 B/D. Although recommended pump limits increase linearly with frequency, the volumetric limit on rotary gas separators is constant, at about 14,000 B/D (513 series).

If any free gas is present, pump stages closer to the intake will see a higher effective rate, and stages closer to the discharge will see a lower effective rate. A floating impeller pump design attempts to balance three basic forces: impeller weight, hydrostatic forces, and hydraulic impact of the fluid.

There is probably always some "downthrust" on individual pump stages, but this is lessened at higher rates. At rates very low on the pump curve, downthrust becomes extreme, reducing efficiency and shortening pump life. Minimum and maximum recommended rates are set based on thrust and efficiencies (see Figure 2, pump tornado).

Abrasives. Sand production through an ESP causes radial wear of the shaft bearings and aggravates wear caused by operating in downthrust. Radial wear on the shaft and bearings will cause excessive pump vibration, resulting in failure of the protector and motor seals. The third wear mechanism in abrasive environments is general erosion of the flow surfaces in the impellers and diffusers. Erosional wear can be particularly severe in a rotary gas separator, literally cutting through the housing.

A small amount of sand production is tolerable, such as the background sand produced from a competent high rate completion. Several modifications to the pumping system can be made to extend runlife if some sand is anticipated. Fixing the pump stages (axially) to the shaft will eliminate stage downthrust, and reduce the loss of efficiency caused by downthrust wear. A fixed impeller pump is not as efficient to begin with as a floating impeller pump, but may have a longer life in a sandy application. The stage thrust is also completely carried by the thrust bearing in the protector section, which may reduce the runlife of this component.

Depth limitation. Conventional (non-deepwater) wisdom places a maximum depth on ESP pumping of about 12,000' due to head and temperature constraints on the system. In most deepwater applications, the pump system will need to be set deeper than this in order to provide sufficient head to keep free gas at a reasonable level without reducing inflow. Total dynamic head requirements even in a deep well should stay within a reasonable range (say, under 12,000') because of the low specific gravity fluids lifted and the relatively high intake pressures. Burst pressure limits on standard pump housings will generally not be exceeded for the same reasons.

Another limitation to be considered would be power (I^2R) losses in the power cable. The voltage drop may be so high in 12,000' of cable that a VSD would be required just to start the pump. In most deepwater applications we will also probably need to run flat profile power cable for clearance reasons. Long stretches of flat cable are subject to voltage imbalance, which may also affect system operation and motor heating.

Motor and Power system. The motors used with ESPs are three phase squirrel cage induction motors, which operate in a manner similar to the induction motors used in surface applications. The size of a downhole motor is limited by the inside diameter of the casing and the need for the produced fluid to flow in the annular space between the motor and casing. These motors are therefore constructed with a number of rotors mounted on a common shaft. Multiple motors can be connected together to further increase the power available.

ESP motors have a definite temperature rating (generally 350°F internal motor winding temperature) determined by deterioration of motor winding insulation. The motor is cooled by the flow of fluids past the motor housing, and both the velocity of the fluids and their heat capacity will control the rate of heat transfer. Normal operating motor internal temperatures run about 80 – 90 °F above ambient, but this can double with low specific heat fluids such as oil and gas.

High voltage motors should be selected to minimize I^2R losses and required cable size. The required voltage at the wellhead is the sum of the motor nameplate voltage and the cable voltage drop. Also, VSD's are generally set up to vary voltage directly with frequency, so surface voltage can get very high. The maximum voltage rating of common ESP power cables and feedthrough systems is 5000 volts, which becomes another design constraint. Transients can also increase the applied voltage above cable or feedthrough ratings.

ESP runtime. One critical aspect of the decision to run ESP's in a new field is the anticipated runlife of the ESP's. The two most common measurements of runtime are "average days to failure" (of a group of failed pumps) and Mean Time Between Failures. Both of these methods still give some measure of central tendency without describing the shape of the failure distribution over time. Runlife is also very dependent on producing conditions (temperature, rate, horsepower, frequency of restarts, design, producing fluids, sand, etc), so that comparison between fields can be problematic.

All documented ESP runlife histories demonstrate a positive skewness, in which the mean exceeds the median, and the median exceeds the mode. A group of 67 high horsepower (450 to 600 HP) ESP systems in the North Sea was matched to an exponential failure distribution function, which is widely used to describe events recurring at random in time, such as the time between failures of electronic equipment. This data showed a mean runlife of 246 days, a median of 192 days, and a mode of 100 days. There is also a notable trend to shorter runlife at higher horsepowers.

It would be unfair and misleading to apply the statistics above to a new deepwater project without some consideration. An ESP installation in the deepwater GOM should go through the same engineering, quality assurance and testing procedures as would any other piece of novel equipment in a critical well. This is far beyond the treatment of a typical land-based ESP installation. . If every reasonable action were taken to ensure quality installations, it would be reasonable to anticipate a median runlife of one to two years over time in the deepwater GOM. However, with the lack of experience in ESP operations in the GOM, a steep learning curve should be anticipated.

Wellbore Configuration. In a conventional installation, the ESP is suspended from the bottom of the tubing with the power cable banded or clamped to the tubing and exiting the tubing hanger through one of several types of wellhead penetrators. If a packer is required above the ESP, an additional cable feedthrough must be provided. From the bottom up, the ESP installation includes the motor, the protector (also called seal, or equalizer), the pump intake (which may be a rotary gas separator), and the pump itself.

If gas is vented up the casing, this will require producing gas out of one of the casing valves at surface, a practice unfamiliar in the GOM. If rotary gas separation (or even natural gas venting) is required as well as a production packer for well control, the packer must also be vented with at least a 1" i.d. opening. A small SCSSV can be run on the vent (casing) side above the packer, and controlled either in parallel or separately from the production SCSSV (see Figure 3).

Variations to the basic design may include:

1. a side string above the production packer to keep gas off of the casing wall,
2. a complete backup gaslift system with a sliding sleeve above the ESP,
3. concurrent ESP and gaslift, which could reduce ESP equipment size to reasonable values in high horsepower applications,
4. a conventional ESP system with fullbore shutoff below the pump
5. coil-tubing deployed ESP.

Gaslift Design

Design process. The most common artificial lift method in the GOM is gaslift, due to a ready supply of gas, its inherent simplicity and versatility, and an extensive experience base. ESP's are mostly used in water source wells (seawater or shallow formation). In order to design a gaslift system for a new project, we need to anticipate inflow and fluid properties over time, and have an understanding of the limitations imposed by surface systems and wellbore mechanical details. Lift gas injection volumes and pressures will change continually over the life of individual wells.

Gaslift performance curves are used to determine the benefit associated with gaslift through the life of a well. Gaslift performance curves plot well production versus gas injection as shown in Figures 4 - 6. Each performance curve is a function of inflow conditions, so a given well's performance curve will change over the life of a well.

An "optimum" gas injection rate is chosen somewhat to the left of the performance curve "peak", as there is little additional production benefit with additional gas injection near the "peak". In practice, gas injection is optimized for a group of wells by the "equal slopes" method, where additional injection provides the same production benefit to all wells in the system.

Optimum mandrel spacing will change for each inflow condition over time, but a real mandrel spacing must be robust over the life of the well. Mandrel spacings can be determined by hand by creating a "window" over which the gaslift design must work. This can be done by plotting flowing gradients from early-, mid- and late-life cases on the same sheet and setting mandrel spacings so that an active injection point is always available. If casing pressures are high enough, a typical deepwater well should still require eight or less mandrels.

Example gaslift benefit. The performance curves in Figures 4 - 6 illustrate the gaslift benefit for a typical deepwater well in both depletion and waterflood scenarios. The performance curves are used to illustrate the selection of gaslift system pressure and anticipated injection rates over time. In this example, the deepest gaslift mandrel is set at 16,000' and the well is completed with 3-1/2" tubing.

In the early life depletion case, Figure 4 shows that the natural flow rate is just over 5300 B/D. The maximum gaslift benefit achievable is less than 100 B/D on a 2800 psi system. Beyond an injection GLR of 500 scf/bbl, additional gas injection just adds to the friction drop in the tubing and decreases the benefit. At lower system pressures the injection depth is shallower, resulting in less gaslift benefit. This well is very nearly outflow-constrained.

Later in the life of the example well (Figure 5), the system pressure benefit of 2800 psi over 2400 psi has virtually disappeared. Gaslift benefit is also at its maximum for the life of this well, because the producing GOR increases after this time. In all cases studied, gaslift showed a minimal benefit when producing GOR was over 2000 scf/bbl.

In the late life waterflood case shown in Figure 6, where the water cut is now 87.9%, the well has loaded up and will not produce without artificial lift. Figure 6 shows that production is not initiated until an injection GLR over 200 scf/bbl is reached. A good pick for the optimum injection GLR might be about 500 scf/bbl on the 2400 psi system, corresponding to an injection rate of about 1.6 MMCFD.

Similar analysis of other producing conditions yields the following results:

1. Where gaslift is required, 3-1/2" tubing cases sustain higher production rate than 2-7/8" cases, but also require more gas injection.
2. At any point in the life of a well, gaslift benefit is mostly a function of producing GOR, watercut, and reservoir

pressure. Optimum injection GLR's and are also a strong function of production rate, watercut and producing GOR, and will thus vary over the life of the well.

3. Many wells will achieve a low abandonment pressure on natural flow with 2-7/8" tubing. These tend to be cases with producing GOR's above 2000 scf/bbl, where gaslift benefit is insignificant.

4. In scenarios where the producing GOR of the wells stays below 2000 scf/bbl, lower abandonment pressure achievable through gaslift (or ESP) creates a substantial increase in ultimate recovery.

5. In all waterflood cases, gaslift shows a significant benefit over natural flow. In some cases, gaslift is required to sustain production beyond producing watercuts of about 35%.

In order to make final decisions on whether to gaslift specific wells and what tubing size to use, simulations should be run to determine the incremental recovery and economics associated with the different options. The optimum injection GLR's chosen by the above process are used to create outflow curves to feed into the simulations.

Gaslift equipment considerations. Gaslift valve test rack open (TRO) pressures are the limiting factor in determining casing pressure. TRO limits are always higher in 1" than in 1-1/2" valves. The official TRO limit on the BK valve is 2100 psig, but with extra thick bellows it is common practice to set TRO's as high as 2800 psig (North Sea). A TRO of 3000 psig should be used as the absolute extreme.

In all design cases with the 2400 psi system, TRO's are between 2200 psig and 2800 psig, with the higher pressures at the bottom of the well. Considering the negligible production benefit of higher pressure systems, and the limitation imposed by TRO pressures, the 2400 psi system design pressure (and no more) would be chosen for this study. In most "early-life" cases, system pressures less than 2400 psi limit production significantly.

There is a recognized safety risk associated with gaslift system pressures this high, particularly considering the volume of gas stored in the casing. To lessen this risk, it may be advisable to install a shallow dual packer with an annular SCSSV. This system would reduce the risk associated with the significant high pressure gas storage volume in the casing. An extension to this system would be to run a dual tubing string from the surface, with the short string used for lift gas injection.

Lift Curves

Lift (outflow) curves describe the pressure behavior of the outflow (tubing) system at different rates at a given point in the system, usually the sandface. The intersection of the lift curve and the IPR (inflow performance relationship) curve defines the production rate and flowing pressure at the sandface. The two curves together are called the *system* curve, and the intersection is called the *system* solution.

Generalized lift curves are constructed from gradient traverses (a plot of pressure vs. depth in the tubing) for a range of anticipated rates and fluid parameters (such as water cut and GOR). At a specified depth, the lift curve plots the flowing pressure needed to produce different rates into a constant tubing head pressure. At very low rates, the required tubing pressure at depth begins to increase with decreasing rate (the curve is U-shaped). This represents a region of unstable two phase flow or "heading", where liquid fall back and slugging become a concern. Outflow is unstable to the left of the lift curve minima.

Lift curves for gas lift and natural flow are *independent* from inflow conditions. The production rate and wellbore flowing pressure can be determined at any time in the life of a well by finding the intersection of the inflow and outflow curves.

Lift curves for ESP. A gradient curve for an ESP is shown in Figure 7. The pressure increase across the pump is dependent on fluid conditions at the intake, which depends on intake pressure. For this reason, a lift curve for an ESP <u>cannot</u> be considered apart from the IPR curve. This complicates the analysis, because *generalized* lift curves cannot be constructed for a given ESP design, as they can be for gas lift or natural flow. Each lift curve is <u>only</u> valid for the particular IPR point for which it was generated.

A lift curve for an ESP is created by picking an inflow condition from the IPR curve, calculating the pressure drop to the pump intake, then the pump contribution, and finally the pressure drop to a specified tubing head pressure. In this manner the tubing curve is "translated" down through the pump to the sandface. The intersection of the IPR curve and the ESP-modified lift curve gives the system solution at the sandface.

Nodal analysis packages capable of calculating lift curves for ESP's generally do so from a single-point design (pump-staging and frequency). Curves thus generated do not account for free gas limits at the intake, recommended operating ranges (i.e. the pump tornado), horsepower requirements, or the fact that the system would be operated at a different frequency for different inflow conditions.

The solution to this is to design a pump that will meet all constraints over successive IPR points just by changing frequency. A production rate and sandface flowing pressure can be generated that corresponds to each of these points. The "composite" lift curve contains short lift curves that meet all constraints from each single point design, as shown in Figure 8.

Artificial Lift Comparison. Gaslift outflow curves are independent from the IPR curve, unlike ESP curves. However, creating a performance curve to determine the "optimum" injection GLR at each inflow condition over time still requires a complete gaslift design at each IPR point. Injection at different GLR's will yield different outflow curves. Therefore, discrete designs have to be run over the entire range of expected inflow conditions for either gaslift or ESP, and lift curves generated for each design. A table can be created that defines the validity range of each set of lift curves in terms of production rate or watercut, and the simulator set up to apply the appropriate set of curves based on the table.

System curves are plotted in Figure 9 for an example deepwater well to compare natural flow, gaslift, and ESP performance. The example chosen has a low GOR (800 scf/bbl), so significant artificial lift benefit would be expected. Since the well rate and sandface flowing pressure occur at the intersection of the inflow and outflow curves, the "lowest" outflow curve achieves the highest production rate.

It is seen in Figure 9 that both ESP and gaslift can produce at higher rates than natural flow. It would seem at first glance that ESP's could significantly outproduce the other systems over the entire life of the well. Recall however that the ESP designs are only valid at the indicated design points. In practice, the pump frequency would generally be lowered as inflow pressures decline.

The "real" outflow curve would follow a path dictated by system constraints (the pump tornado, frequency limitation, GVF at the pump intake, and brake horsepower). This curve might have any shape, including loops (see example in figure 8). Unlike gaslift and natural flow curves however, the "path" through the different ESP curves is stable at all points. For a quick comparison, it is probably more valid to plot the "path" between the ESP lift curves to determine where the ESP could really produce.

Hydrates

Deepwater wells have the potential for hydrate formation due to cooling in the risers from the sea floor to the host facility. Field experience indicates that hydrate plugs can form in the absence of free gas, and at water cuts less than 1%. While this may affect any well, note that gas injection reduces fluid temperatures and ESP's heat fluids.

Since hydrate formation temperature increases with pressure, shut-in scenarios must be considered in artificial lift design. Tubing pressure can rise to as high as casing pressure (or higher) when a gaslifted well is shut-in. Hydrate plugs can also form anywhere in the tubing string down to (or below) the mudline. In the absence of any hydrate prevention schemes, wells should be operated so that all points in the tubing string stay outside the hydrate formation region.

Artificially high cut-off rates may therefore be imposed on different artificial lift systems. There are no existing chemical treatments (including methanol) that can economically depress the hydrate formation temperature on a continuous basis. There are however various operations philosophies (such as venting and blowdown) and several "technology" options (e.g. electric gaslift valves or downhole electric heating) that could be used to reduce the hydrate-imposed cutoff rate.

Conclusions

To compare ESP to gaslift or natural flow, designs must be performed over the entire range of anticipated inflow conditions. Systems should be chosen that produce over the widest possible range without having to pull the well. At certain ranges of production, pressure, GOR, and watercut, ESP's can significantly outproduce gaslift, but might run into constraints that would either require a new pump design, reduced production, or a change back to gaslift or natural flow.

Artificial lift will provide the most benefit when producing GOR's remain below 2000 scf/bbl, and as water cuts begin to increase. To provide adequate lift in typical deepwater GOM conditions, gaslift system pressures will tend to be very high (above 2000 psi), and ESP systems will tend to be high horsepower.

Full reservoir simulations should be run in most cases to determine the most economic solution. Artificial lift system limitations must be understood in order to create valid lift curves for the simulator. Economics must include the probable impact of well downtime as well as the cost of well servicing.

Nomenclature

GLR = gas liquid ratio, scf/bbl
GOR = gas oil ratio, scf/bbl
GVF = gas volume fraction

Acknowledgments

I would like to thank the management of Shell Deepwater Development Inc. for their support of this work and permission to publish. I would also like to thank my wife, Annette G. Stair, for graciously allowing me to work on this paper on our honeymoon.

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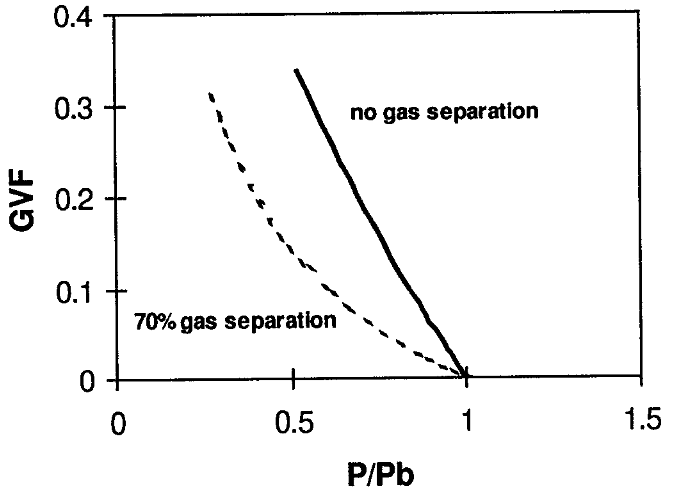

Fig.1 – Gas volume fraction as a function of pressure below bubble point. The impact of gas separation at the intake is shown.

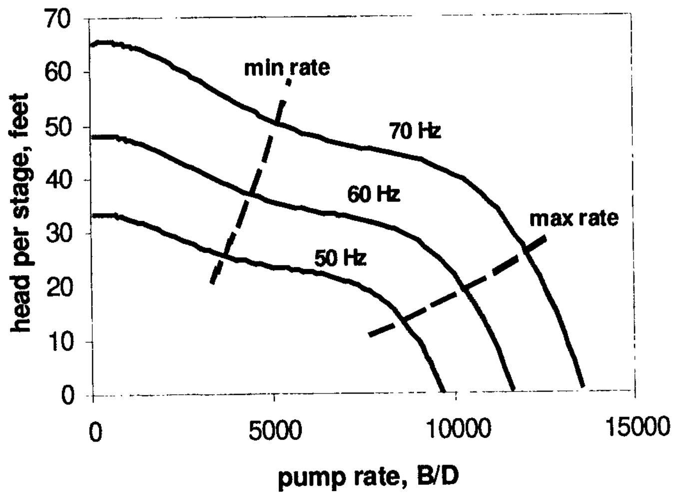

Fig. 2 – Typical pump curve. The region between low and high frequencies and the minimum and maximum recommended rates is called the "pump tornado".

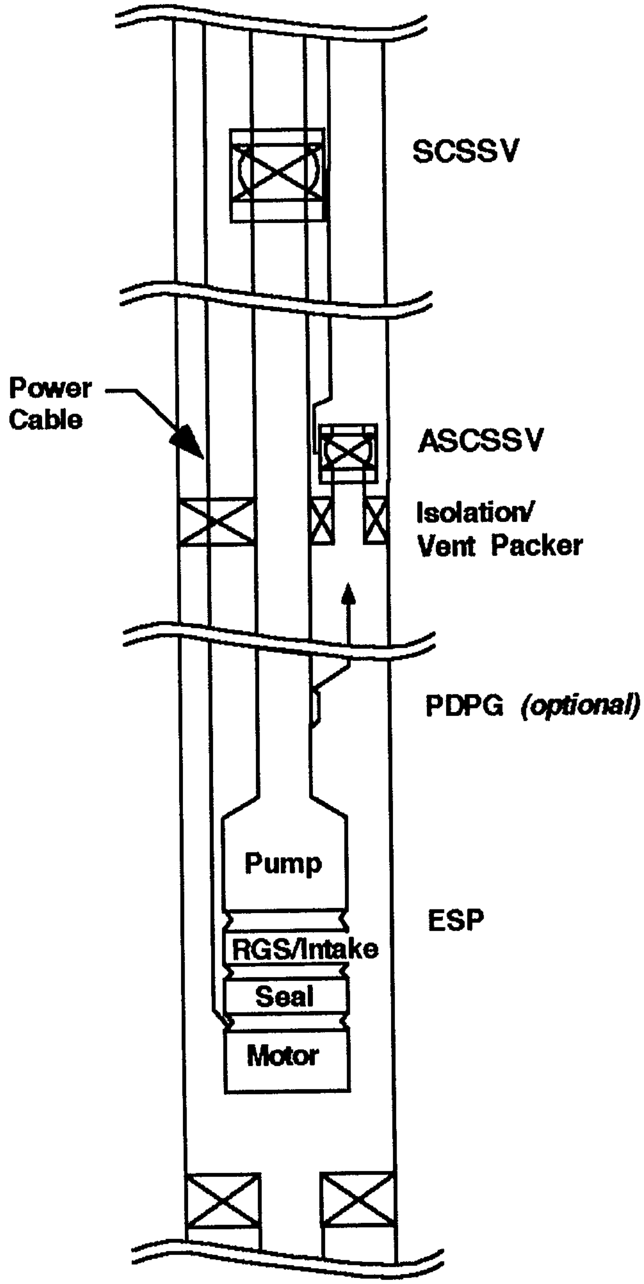

Fig. 3 – ESP with gas separator, packer and annular SCSSV.

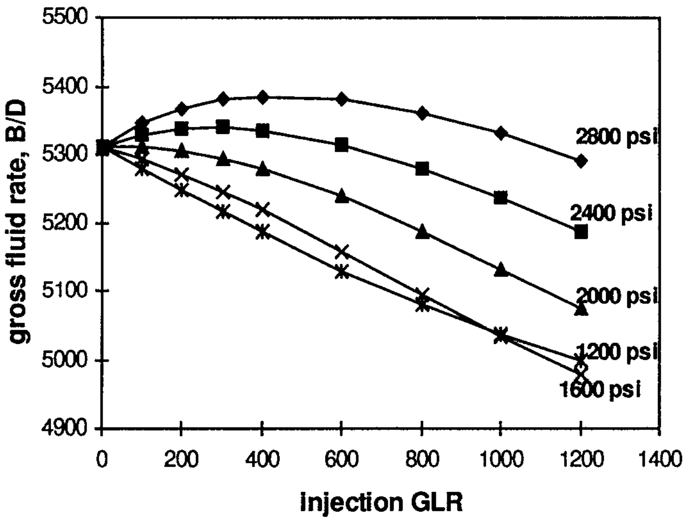

Fig. 4 – Gaslift performance curve for early life depletion case

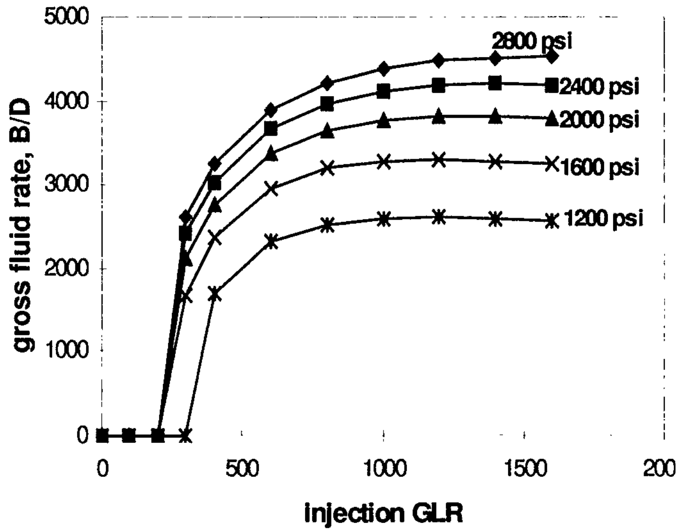

Fig.6 – Gaslift performance curve for late-life waterflood case.

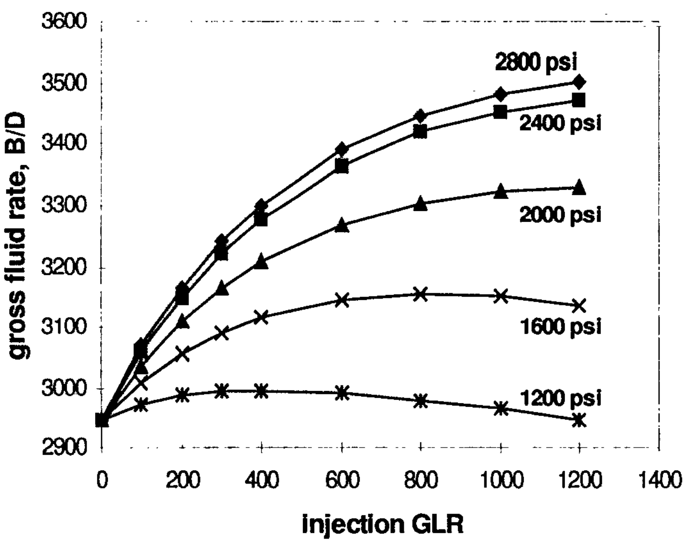

Fig. 5 – Gaslift performance curve for mid-life depletion case

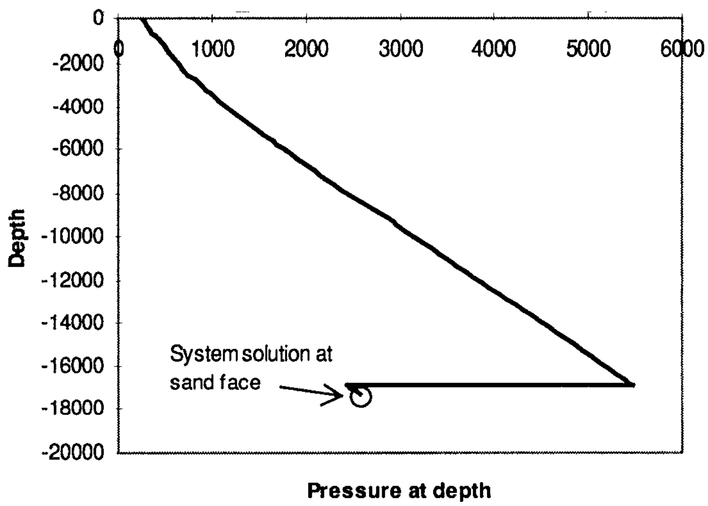

Fig. 7 – Gradient curve for ESP

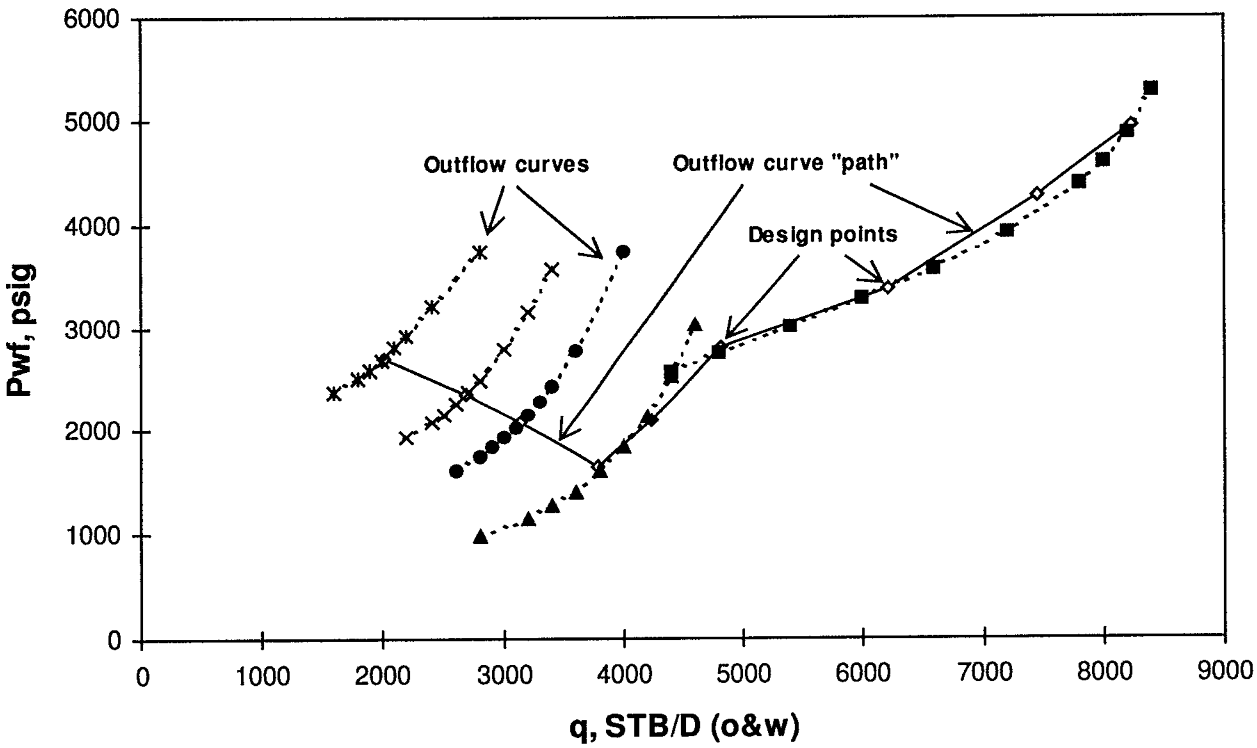

Fig. 8 – Outflow curves for ESP, showing individual design points and outflow curve "path".

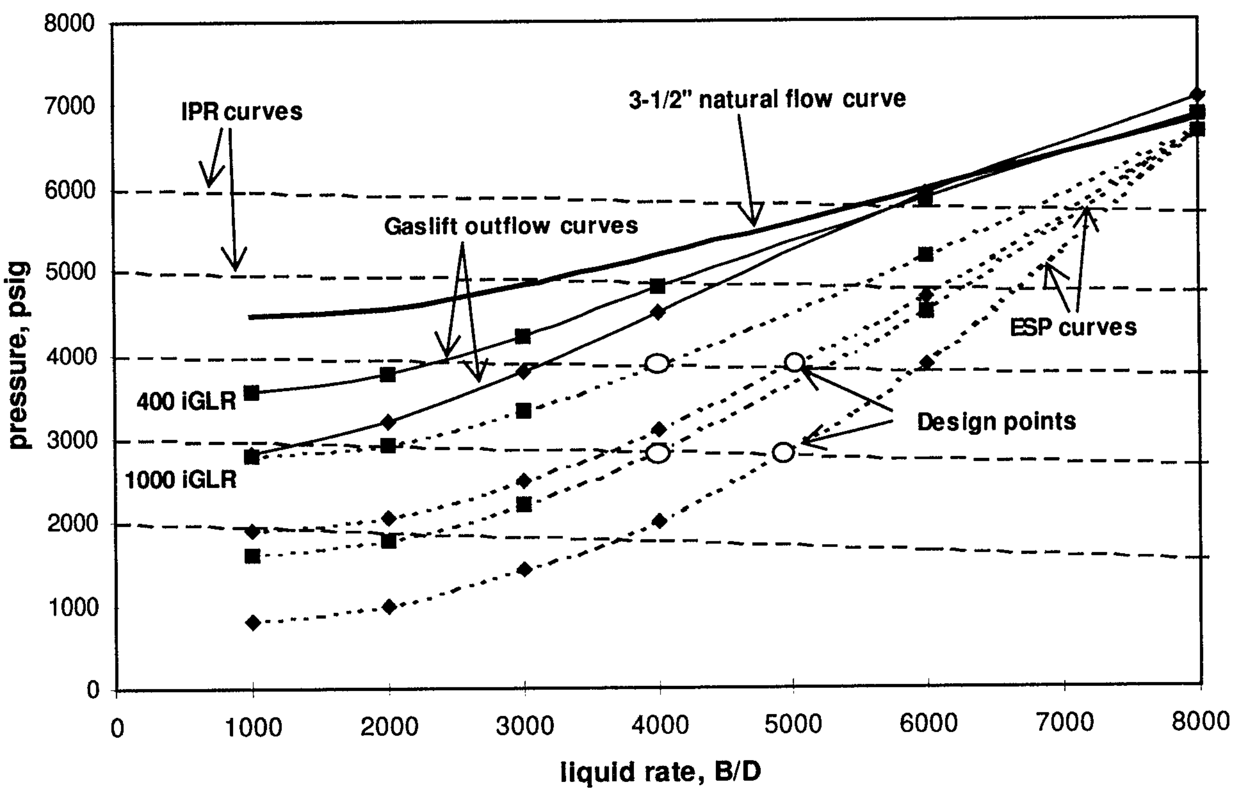

Fig. 9 – System curves for natural flow, gaslift and ESP