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New Recommendations and Comparisons for Artificial Lift Method Selection

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ABSTRACT

The selection of the proper artificial lift method is critical to the long term profitability of most producing wells. This paper compares the main selection attributes for the current, eight major artificial lift methods and provides practical guide lines on the performance and operating capabilities for the methods. The methods covered include beam pumping, progressing cavity pump, electric submersible pump, hydraulic reciprocating pump, hydraulic jet, continuous gas lift, intermittent gas lift, and plunger lift.

INTRODUCTION

The selection of the correct artificial lift method is critical to the long term profitability of oil, water, and some gas wells. A poor choice can substantially reduce production and increases operating costs. Once a decision has been made on the type of lift to install on a well, it is hardly ever reviewed to determine that it was and still is the best lift method under existing conditions. In addition, changing the type of lift costs additional money and requires some one admitting that the wrong system was initially selected. Although prudent production engineering requires continuous review of the lift method's performance with an aim to modify the operating parameters, or even change out the method, the usual practice is that once a method is chosen it stays in place "forever."

The proper selection of the best lift method for a well is typically highly opinionated. If discussions are held with operating personnel, they normally select or try to change out any problem lift method for the one with which they are most familiar. When method selection is discussed with the equipment supplier or even the in-house expert on a specific method, the recommendation normally is that their choice can be made to fit the requirements.

This "force-fit" selection usually results in the extension of the capabilities or operating experience of the selected lift method. However, we typically find that the improvements are made to solve a new problem that was encountered due to the poor original choice. Thus, it becomes very necessary to establish the normal and, more importantly, the practical operating

References at end of paper.

capabilities of the major lift methods that can be used.

In this paper, eight major artificial lift methods are compared. This is done by extending the comparisons previously discussed by Brown, et. al., in their book; The Technology of Artificial Lift. The basis of this paper was formulated during discussions at the July, 1991, SPE Forum on New Advances in Artificial Lift. Four new lift methods were added to the previously covered comparisons. These include progressing cavity pump, hydraulic jet pump, intermittent gas lift and plunger lift. Additionally, 31 different design and operational attributes are included for these new comparisons between all eight techniques. A selected Bibliography and pertinent references for general and specific artificial lift method usage, capabilities, selection, and comparisons are presented at the end of this paper.

The one thing that should be emphasized is that the performance or capability attributes in this paper are based on practical and proven technology. New advances may extend an individual method's performance. Until the advances are proven to be practical and cost effective over the long term, they should be viewed as remedies to a particular problem. Thus, these current attributes can be used to compare and select the "best" lift method for a new well. Furthermore, the comparison of attributes can be used to determine if the current lift method for a well previously, may have been incorrectly chosen and that another method should be considered as a replacement.

DISCUSSION

The selection of the most appropriate artificial lift method has to start up-front when the reservoir, drilling, and completion designs and decisions are being made. This requires very good, open communication between all of these disciplines. Coupled to this are the production requirements and limitations in contract deliverables that have to be met. Thus, good drill stem test and production rate data have to obtained as the first steps on method selection. The drilling and completion scenarios then have a major impact in determining not only the best lift method; but, also what is the overall capability of the well.

The following tables have been developed to aid in comparing all the different production parameters that need to be considered, as a minimum, along with the reservoir, drilling, and completion information. These tables have been divided in three main areas to provide the main emphasis of this paper. Comparing and contrasting the practical capabilities should be done to make the best method selection for the life of the project. Table I presents the 10 different attributes for normal design and overall capabilities comparisons. Table II presents nine different parameters that are grouped under normal operating considerations. Table III presents the 12 lift method parameters that are special problem considerations.

When selecting the "best" lift method, all of these parameters need to be considered. However, there are some items that override which method should be used. As an example, the location is a key factor in method selection. Offshore, arctic, and remote areas may justify or force a different method than the combination of all the other attributes. The cost of energy is very important in some locations; while in today's restricted domestic production, overall efficiency and total operating costs are driving a re-look at what may be the "best" method. Added to this is service of the equipment. This may be very costly in some locations around the world. All of these factors and those discussed in the tables must be considered to determine the final lift method. Thus, the determination of any method needs a "full-cycle" economic justification.

SUMMARY/CONCLUSIONS

1. Each artificial lift method has different lift attributes that must be evaluated foe the specific installation. Of particular importance are the production rate requirements over the life of the project.

2. The attributes of the artificial lift methods are relative to each other and can only be specific for a particular production installation.

3. When all the 31 listed lift attributes are considered, there are some that have more significance than others. One of these is location. This is important since it can significantly affect capital and operating costs, as well as production rates.

4. There are some important over-riding considerations in artificial lift selection. The use of beam pumps should be the first choice if operations are to be done on land. If offshore is the production location, then the method of choice is gas lift. Experience has shown that such choices normally result in optimum production and minimum costs. Thus, these choices should be used at the standard for comparison of the other lift methods. The other lift methods only should be selected where there are definite installation and operational advantages.

5. Once a method is selected, there still needs to be refinement and proper engineering done to design and select all the equipment necessary to make this method actually work for the application. Improper design and operation of the "best" selected method will always "prove" that the selection was not the best in the first place. Thus, once the method is selected and designed, discussions need to take place with operations personnel to provide them with the necessary information, including training, to make this installation economically successful.

6. The limits and relative comparisons listed in these tables are based on the experiences of the authors and are considered "conventional wisdom." Most of these attributes are subject to change with improved technology. In addition, experience may alter some of the listed limits. The authors request that new data be published that will alter these recommended, practical capabilities and improve the industry knowledge on artificial lift selection.

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TABLE I
ARTIFICIAL LIFT - DESIGN CONSIDERATIONS AND OVERALL COMPARISONS

	Rod Pumping	Progressing Cavity	Electrical Submersible Pumping	Hydraulic Reciprocating Pump	Hydraulic Jet Pump	Gas Lift Systems Continuous Flow	Gas Lift Systems Intermittent Lift (if different from continuous flow)	Plunger Lift
Capital Cost	Low to moderate; increases as depth and unit size increases	Low, but increases as depth and pump rate increases.	Relatively low capital cost if electric power available. Costs increase as horsepower increases	Varies but often competitive with rod pumps. Multiple well, central systems reduces cost per well but more complicated.	Competitive to rod pump. Relatively low cost over 1500 BFPD. Cost increases with higher horsepower.	Well gas lift equipment cost low but compression cost may be high Central compression system reduces overall cost per well.	Same as continuous flow gas lift.	Very low if no compressor required.
Downhole Equipment	Reasonably good rod design and operating practices needed. Data bank of failures beneficial. Good selection, operating, and repair practices needed for rods and pumps.	Good design and operating practices needed. May have problems with selection of appropriate stator elastomer.	Requires proper cable in addition to motor, pumps, seals, etc. Good design plus good operating practices essential	Proper pump sizing and operating practices essential. Requires two conductor (power fluid and returns). Single tubing string on packer and casing annulus most common. Clean power fluid is essential.	Requires computer design programs for sizing. Tolerant of moderate solids in power fluid. No moving parts in pump; long service life; simple repair procedures to run and retrieve pump downhole.	Good valve design and spacing essential. Moderate cost for well equipment (valves and mandrels). Typically less than 10 valves needed. Choice of wireline retrievable or conventional valves.	Unload to bottom with gas lift valves; consider chamber for high PI and low BHP wells.	Operating practices have to be tailored to each well for optimization. Some problem with sticking plungers
Efficiency (Operating) [Hydraulic Horsepower/ Input Horsepower (HHP/IHP)]	Excellent total system efficiency. With full pump fillage, efficiency typically 50 to 60%.	Excellent, may exceed rod pumps for ideal cases. Typically system efficiency 50 to 70%.	Good for high rate wells but decreases significantly for <1000 BFPD. Typically total system efficiency is about 50% for high rate well but for <1000 BPD, efficiency typically <40%	Fair to good; usually not as good as rod pumping due to GLR, friction and pump wear. Typical efficiencies run in the 30 to 40% range with GLR >100; may be higher if lower GLR.	Fair to poor; max. efficiency for ideal case 30 % Heavily influenced by power fluid plus production gradient. Typical operating efficiencies of 10 to 20%.	Fair, increases for wells that require small injection GLR's. Low for wells requiring high GLR's. Typically 20%; but, range 5 to 30%.	Poor; normally requires a high injection gas volume/barrel fluid. Typical lift efficiency is 5 to 10%. Improved with plungers.	Excellent for flowing wells No input energy required since uses the energy of the well.
Flexibility	Excellent; can alter SPM, stroke length, plunger size, and run time to control production rate.	Fair, can alter RPM Hydraulic unit provides additional flexibility but added costs.	Poor; for fixed speed Requires careful design. VSD provides better flexibility.	Good to excellent; can vary power fluid rate - thus SPM of downhole pump Numerous pump sizes and pump-to-engine ratios adapt to production and depth requirements	Good to excellent, power fluid rate and pressure adjusts the production rate and lift capacity from no-flow to full design capacity of installed pump Selection of throat and nozzle sizes extend range of volume and capacity	Excellent Gas injection rate varied to change rates. Tubing needs to be sized correctly.	Good, must adjust injection time and cycles frequently.	Good for low volume wells Can adjust injection time and frequency.
Miscellaneous Problems	Stuffing box leakage may be messy and a potential hazard (Anti pollution stuffing boxes are available).	May have limited service in some areas Since newer method, field knowledge and experience limited	Requires a highly reliable electric power system. System very sensitive to changes downhole or in fluid properties	Power fluid solids control essential 15 ppm of 15 micron particle size max to avoid excessive engine wear. Must add surfactant to a water power fluid for lubricity. High pressure power oil leakage may be hazardous. Triplex plunger leakage control required Fluid system requires added tubing string.	More tolerant of power fluid solids; 200 ppm of 25 micron particle acceptable Diluents may be added, if required. Power water, either fresh, produced, or seawater, acceptable.	A highly reliable compressor with 95+% run time required. Gas must be properly dehydrated to avoid gas freezing.	Labor intensive to keep fine tuned, otherwise poor performance. Maintaining steady gas fl[illegible] often causes injection gas problems.	Plunger hang-up, sticking is major problem.
Operating Costs	Low for shallow to medium depth (<7000') land locations with low production (<400 BFPD).	Potentially low, but, short run life on stator or rotor frequently reported.	Varies; if high HP, high energy costs. High pulling costs result from short run life especially in offshore operation. Repair costs often high.	Often higher than rod pumps even for free system. Short run life increases total operating costs.	Higher power cost due to horsepower requirement. Low pump maintenance cost with properly sized throat and nozzle for long run life.	Well costs low. Compression cost vary depending on fuel cost and compressor maintenance.	Same as continuous flow gas lift.	Usually very low unless plunger problem.

TABLE I (CONT.)

	Rod Pump	Progressing Cavity	ESP	Hydraulic	Jet	Continuous Gas Lift	Intermittent Gas Lift	Plunger
Reliability	Excellent; run time efficiency >95% if good rod practices followed.	Good: normally over pumping and lack of experience decreases run time.	Varies; excellent for ideal lift cases; poor for problem areas (very sensitive to operating temperatures and electrical malfunctions).	Good with a correctly designed and operated system. Well site power fluid system minimizes power oil or water problems. Problems or changing well conditions reduces downhole pump reliability. Frequent downtime results from power oil problems, injection pressure, pump maintenance problems and failure of downhole pumps.	Good with proper throat an nozzle sizing for operating conditions. Must avoid operating in cavitation range of jet pump throat, related to pump intake pressure. More problems if pressures >4000 psig	Excellent if compression system properly designed and maintained.	Excellent if there is an adequate supply of injection gas and an adequate low pressure storage volume for injection gas.	Good if well production stable.
Salvage Value	Excellent Easily moved and good market for used equipment.	Fair/Poor; easily moved and some current market for used equipment.	Fair; Some trade in value. Poor open market values	Fair; Some trade in value. Fair market for triplex pump. Good value for well site system that can be easily moved well-to-well.	Good; easily moved well-to-well. Fair; some trade in value. Fair market for triplex pump.	Fair: Some market for good used compressors and mandrels/valves.	Same as continuous flow gas lift.	Fair; some trade in value. Poor open market value.
System (Total)	Straight forward and basic procedures to design, install & operate following API specs and RP's. Each well is an individual system	Simple to install and operate Each well an individual system	Fairly simple to design but requires good rate data System not forgiving. Requires excellent operating practices. Follow API RPs in design, testing, and operation Each well is an individual producer using a common electric system.	Simple manual or computer design well application. Operating procedures easily learned. Free pump easily retrieved for servicing. Individual well unit very flexible but extra cost. Requires attention. Central plant more complex; usually results in test and treatment problems.	Available computer design program for application design. Basic operating procedures for downhole pump and well site unit. Free pump easily retrieved for on-site repair/replacement. Downhole jet often requi as trial and error to arrive at best/optimum jet	An adequate volume, high pressure, dry, non-corrosive and clean gas supply source is needed through out the entire life. System approach needed. Low back pressure beneficial. Good data needed for valve design and spacing. API specs and design/operating RP's should be followed.	Same as continuous flow gas lift.	Individual well or system. Simple to design, install and operate.
Usage/Outlook	Excellent, used on about 85% of USA artificial lift wells. The normal standard artificial lift method	Limited to relative shallow wells with low rates. Used on less than 0.5% US lifted wells. Primarily gas well de-watering	An excellent high rate artificial lift system. Best suited for <200°F and >1000 BFPD rates. Most often used on high water cut wells. Used on about 5% US lifted wells.	Often used as a default artificial lift well system. Good for flexible operation; wide rate range to relatively deep, high volume, high temperature, deviated, oil wells. Used on <5% US lifted wells	Good for higher volume wells requiring flexible operation, wide depth range, high temperature, high corrosion, high GOR, significant sand production. Used on <1% US lifted wells. Sometimes used to test wells that will not flow offshore.	Good, flexible, high rate artificial lift system for wells with high bottom hole pressures. Most like a flowing well. Used on about 10% US lifted wells; mostly offshore.	Often used as a default artificial lift method in lieu of rod pumps. Also a default for low pressure wells on continuous gas lift. Used on <1% of US wells.	Essentially a low liquid rate, high GLR lift method. Can be used for extending flow life or improving efficiency. Ample gas volume and/or pressure needed for successful operation. Used on <1% US wells.

TABLE II
ARTIFICIAL LIFT - NORMAL OPERATING CONSIDERATIONS

	Rod Pumping	Progressing Cavity	Electrical Submersible Pumping	Hydraulic Reciprocating Pump	Hydraulic Jet Pump	Gas Lift Systems Continuous Flow	Gas Lift Systems Intermittent Lift (if different than continuous flow)	Plunger Lift
Casing Size Limits (restricts tubing size)	Problems only in high rate wells requiring large plunger pumps Small casing sizes (4.5 and 5.5") may limit free gas separation	Normally no problem for 4.5" casing and larger; but, gas separation may be limited	Casing size will limit use of large motors and pumps. Avoid 4.5" casing and smaller. Reduced performance inside 5.5" casing depending on depth and rate	Larger casing required for parallel free or closed systems. Small casing (4.5 & 5.5") may result in excessive friction losses and limits producing rate	Small casing size limits producing rate at acceptable pressure drop level. Larger completion casing may be required if dual strings run.	The use of 4.5" and 5.5" casing with 2" nominal tubing normally limits rates to <1000 BPD. For rates >5000 BPD larger (>7") casing and ≥ 4.5" tubing needed.	Small casing (4.5 and 5.5") normally is not a problem for this relatively low volume type lift.	Small casing suitable for this low volume type lift.
Depth Limits	Good; rod or structure may limit rate at depth Effectively, about 150 BPD at 15,000 feet	Poor, limited to relative shallow depths Possibly 5000 feet	Usually limited to motor HP or temperature. Practical depth about 10,000 feet	Excellent: Limited by power fluid pressure (5000 psi) or HP. Low volume/high lift pump operating at depths to 17,000 feet.	Excellent; Similar limits as reciprocating pump. Practical depth 20,000 feet.	Controlled by system injection pressure and both gas and fluid rate. Typically, for 1000 BPD with 2.5" tubing and a 1440 psi lift system and a 1000 GLR, has an injection depth < 10,000'.	Usually limited by fall-back; few wells > 10,000 ft.	Typically <10,000 ft.
Intake Capabilities	Excellent: <25 PSI provided adequate displacement & gas venting. Typically about 50 to 100 psig	Good: < 100 PSI provided adequate displacement & gas venting.	Fair if little free gas (i.e. <250 PSI pump intake pressure). Poor if pump must handle above 5% free gas.	Fair: Not as good as rod pumping. Intake pressure <100 PSIG usually results in frequent pump repairs. Free gas reduces displacement efficiency and service life.	Poor to fair, >350 psig to 5000 ft. with low GLR. Typical design target is 25% submergence.	Poor: Restricted by the gradient of the gas lifted fluid. Typically moderate rate is limited to about 150 psi per 1000 feet of injected depth. Thus, the back pressure on 10,000' well may be >1500 psig.	Fair when used without chambers. PIP > 250 PSI for 10,000' well. Good when used with chamber. PIP of <250 PSI feasible at 10,000'.	Good: Bottom hole pressures <150 PSI at 10,000 feet for low rate, high GLR wells.
Noise Level	Fair; moderately high for Urban areas.	Good; surface prime mover only noise.	Excellent; very low noise. Often preferred in urban areas if production rate high.	Good; well noise low. Well site power fluid units can be sound proofed.	Same as hydraulic recip. pump.	Low at well but noisy compressor.	Same as continuous flow.	Low at well.
Obtrusiveness	Size and operation are drawbacks in populated & farming areas	Good; low profile surface equipment	Good; low profile but requires transformer bank	Fair to good; wellhead equipment low profile. Requires surface treating and high pressure pumping equipment. Free pump can be retrieved into lubricator to avoid oil spillage	Same as hydraulic recip. pump	Good low profile; but, must provide for compressor. Safety precautions must be taken for high pressure gas lines.	Same as continuous flow.	Good.
Prime Mover Flexibility	Good, both engines or motors can be used easily (Motors more reliable and flexible)	Good, both engines or motors can be used.	Fair, requires a good power source without spikes or interruptions Higher voltages can reduce losses	Excellent, prime mover can be electric motor, gas or diesel fired engines or motors.	Same as hydraulic recip. pump.	Good; engines, turbines or motors can be used for compression	Same as continuous flow.	None required.
Surveillance	Excellent; can be easily analyzed based on well test, fluid levels, etc. Improved analysis by use of dynamometers and computers	Fair; analysis based on production and fluid levels only. Dynamometers and POCs not possible to use	Fair, electrical checks but special equipment needed otherwise.	Good/Fair; downhole pump performance can be analyzed from surface power fluid rate and pressure, SPM and producing rate. Pressure recorder can be run and retrieved on free pump.	Same as hydraulic recip. pump.	Good/Excellent; can be analyzed easily. BHP and prod. log surveys easily obtained. Optimization and computer control being attempted.	Fair, complicated by standing valve and fall back.	Good; depends on good well tests and well pressure chart.
Testing	Good; well testing simple with few problems using standard available equipment and procedures.	Good, well testing simple with few problems.	Good; simple with few problems. High water cut and high rate wells may require a free water knock out.	Fair; well testing with standard individual well units present few problems. Well testing with a central system more complex; requires accurate power fluid measurement.	Same as hydraulic recip. pump. Three stage production test can be conducted by adjusting production step rates, pressured recorder in place to monitor intake pressure. Current IPR development possible.	Fair; well testing complicated by injection gas volume/rate.	Poor; well testing complicated by injection gas volume/rate. Measurement of both input and outflow gas a problem. Intermittent flow can cause operating problems with separators, treaters and tanks.	Well testing simple with few problems.

TABLE II (CONT.)

	Rod Pump	Progressing Cavity	ESP	Hydraulic	Jet	Continuous Gas Lift	Intermittent Gas Lift	Plunger
Time Cycle and Pump Off Controllers Application	Excellent if well can be pumped off	Poor; avoid shutdown in high viscosity/sand producers.	Poor, soft start and improved seals/protectors recommended.	Poor; possible with electric drive well site unit but fair risk of pump restart problem. Usually controlled only by displacement checks; pump-off control not currently developed.	Poor, does not appear applicable due to intake pressure requirement higher than pump-off.	Not applicable to continuous flow gas lift	Poor, cycle must be periodically adjusted. Labor intensive.	Not applicable.

TABLE III
ARTIFICIAL LIFT - SPECIAL PROBLEMS CONSIDERATIONS

	Rod Pumping	Progressing Cavity	Electrical Submersible Pumping	Hydraulic Reciprocating Pump	Hydraulic Jet Pump	Gas Lift Systems Continuous Flow	Gas Lift Systems Intermittent Lift (if different than continuous flow)	Plunger Lift
Corrosion/Scale Handling Ability	Good to excellent, batch treating inhibitor down annulus feasible	Good, batch treating inhibitor down annulus feasible.	Fair, batch treating inhibitor only to intake unless shroud is used	Good/Excellent: batch or continuous treating inhibitor circulated downhole with power fluid for effective control	Good/Excellent; inhibitor with power fluid mixes with produced fluid at entry of jet pump throat. Batch treat down annulus.	Good. Inhibitor in the injection gas and or batch inhibiting down tubing feasible. Steps must be taken to avoid corrosion in injection gas lines.	Same as continuous flow.	Fair, normal production cycle must be interrupted to batch treat the well.
Crooked/ Deviated Holes	Fair; increased load and wear problems. High angle deviated holes (>70°) and horizontal wells are being produced. Some success in pumping 15°/100' dogleg severity with use of rod guides.	Poor to fair, increased load and wear problems. Currently, very few known installations	Good; few problems. Limited experience in horizontal wells. Requires long radius wellbore bends to get through	Excellent. If tubing can be run in the well, the pump will pass through the tubing. Free pump retrieved without pulling tubing. Operates in horizontal wells. Through-flow line (TFL) use feasible.	Excellent, short jet pump can pass through doglegs up to 24 degrees per 100 ft in 2-3/8" tubing. Same conditions as recip pump.	Excellent, few wireline problems up to 70° deviation for wireline retrievable valves	Same as continuous flow	Excellent
Duals Application	Fair; parallel 2x2" low rate duals feasible inside 7" casing. Duals inside 5.5" casing currently not in favor; potential gas problem from lower zone. Increased mechanical problems. Duals result in producing one zone below packer.	No known installations	No known installations. Larger casing required. Possible run & pull problems	Fair, three string non-vented application have been made with complete isolation of production and power fluid from each zone. Limited to low GLR and moderate rates	Same as recip. except can handle higher GLR with sufficient surface horsepower	Fair: Dual gas lift common but good operating of dual lift complicated and inefficient resulting in reduced rates. Parallel 2x2" tubing inside 7" casing and 3x3" inside 9-5/8" casing feasible.	Same as continuous flow.	No known installations
Gas Handling Ability	Good if can vent and use gas anchor with proper designed pump. Poor if must pump (>50%) free gas.	Poor if must pump any free gas	Poor for free gas (i.e., >5% through pump). Rotary gas separators helpful if solids not produced	Good/Fair; Concentric fixed pump or parallel free permits gas venting with suitable downhole gas separator below pump intake. Casing free pump limited to low GLR	Similar to recip. except jet can handle higher GLR. Free gas reduces efficiency but helps lift. Vent free gas if possible. Use a gas anchor	Excellent, Produced gas reduces need for injection gas.	Same as continuous flow	Excellent
Offshore Application	Poor: must design for unit size, weight and pulling units space	Poor, may have application. However, pulling unit needed	Good, must provide electrical power and service pulling unit	Fair, pump runs and operates well in highly deviated wells. Requires deck space for power fluid pump(s) and preferably well site type power fluid system to avoid increased production treating capacity. Power water may be used in CPF system. Power oil a potential fire/safety problem	Good, produced water or seawater may be used as power fluid with well site type system or power fluid separation before production treating system	Excellent, most common method if adequate gas	Poor in wells needing sand control. Use of standing valve risky. Heading causes operating problems.	Excellent for correct application

TABLE III (CONT.).

	Rod Pump	Progressing Cavity	ESP	Hydraulic	Jet	Continuous Gas Lift	Intermittent Gas Lift	Plunger
Paraffin Handling Capability	Good/Excellent; hot water/oil treating and/or use of scrapers possible. However, these increase operating costs.	Fair; tubing may need treatment Rod scrapers not possible to use.	Fair; hot water/oil treatments, mechanical cutting, batch inhibition possible.	Good/excellent; heated power water/oil circulates heat to downhole pump to minimize build-up. Hot water/oil treatments, mechanical cutting, Inhibition possible. Soluble plugs can be run if done frequently enough For "free" pump system, pumps can be surfaced on a schedule.	Same as recip. pump.	Good; mechanical cutting sometimes required Injection gas may aggravate an existing problem.	Same as continuous flow.	Excellent; cuts paraffin and removes small scale deposits.
Slim Hole Completions (2-7/8' production casing string)	Feasible for low rates (< 100 BPD) and low GOR (< 250).	Feasible if low rates, low GOR's and shallow depths but no known installations.	No known installations.	Possible but may have high friction losses or gas problems. Has been used when moderate production rates and low GLR.	Same as recip. pump except may handle higher GLR.	Feasible but can be troublesome and inefficient.	Same as continuous flow.	Good; similar to casing lift but must have adequate formation gas.
Solids/Sand Handling Ability	Fair for low viscosity (< 10 cp) production improved performance for high (> 200 cp) viscosity cases May be able to handle up to 0.1% sand.	Excellent; up to 50% sand with high viscosity (> 200 cp) crude. Decreases to 10% sand for water.	Poor; requires < 200 PPM solids. Improved wear resistant materials available at premium cost.	Poor; requires < 10 PPM solids power fluids for good run life. Also produced fluids must have low solids (< 200 ppm of 15 micron particles) for reasonable life. Fresh water injection into power stream may solve salt buildup in pumps.	Fair/Good; jet pumps are operating with 3% sand in produced fluid Power fluid to jet pump can tolerate 200 ppm of 25 micron particle size. Fresh water treatment for salt build up possible.	Excellent; limit is inflow and surface problems. Typical limit is 0.1% sand for inflow and outflow problems.	Fair; standing valve may cause problems.	Sand can stick plunger. Plunger wipes tubing clean.
Temperature Limitation	Excellent; currently used in thermal operations. (550°F)	Fair; limited to stator elastomer. At present normally below 250°F.	Limited to < 250°F for standard & < 325°F for special motors & cable	Excellent; standard materials to 300° F. Operating to 500°F feasible with special materials.	Excellent; possible to operate to 600° F with special materials	Excellent; need to know temperatures to design bellows-charged valves Typical max. of 350°F.	Same as continuous flow.	Excellent.
High Viscosity Fluid Handling Capability	Good for up to < 200 cp viscosity fluids and low rates (400 BPD) Rod fall problem for high rates. Higher rates may require diluent to lower viscosity.	Excellent for high viscosity fluids provided no stator/rotator problems.	Fair; limited to about 200 CP. Increases HP and reduces head. Potential solution is to use 'core flow' with 20% water.	Good; > 8° API production with < 500 Cp possible. Power fluids can be used to dilute low gravity production.	Good/Excellent; > 8° API production with < 800 Cp possible. Power oil of > 24° API and < 50 cp or water power fluid reduces friction losses.	Fair; few problems for > 16° API or below 20 CP viscosity. Excellent for high water cut lift even with high viscosity oil.	Same as continuous flow.	Normally not applicable.
Volume High Lift Capabilities	Fair, restricted to shallow depths using large plungers Maximim rate about 4000 BFPD from 1000' & 1000 BFPD from 5000'.	Poor, restricted to relatively small rates. Possibly 2000 BFPD from 2000' and 200 BFPD from 5000'	Excellent, limited by needed HP and can be restricted by casing size. In 5.5' casing can produce 4000 BFPD from 4000' W/240 HP. Tandem motors can be used to increase HP but also increases operating costs.	Good; limited by tubulars and HP. Typically 3000 BFPD from 4000' and 1000 BFPD from 10,000' W/ 3500 PSI system.	Excellent; up to 15,000 BTPD with adequate flowing bottom hole pressure, tubular size and horsepower	Excellent; restricted by tubing size and injection gas rate and depth. With 4' nominal tubing rates of 5000 BPD from 10,000 feasible with 1440 psi injection gas and GLR of 1000.	Poor; limited by cycle volume and number of possible injection cycles. Typically about 200 BFPD from 10000' with < 250 PSI PIP.	Poor, limited by number of cycles. Possibly 200 BFPD from 10000'.
Volume Low Lift Capabilities	Excellent, most commonly used method for wells producing < 100 BFPD	Excellent for < 100 BFPD shallow wells	Generally poor; lower efficiencies and high operating costs < 400 BFPD.	Fair; not as good as rod pumping. Typically 100 to 300 BFPD from 4000 to 10,000 ft. > 75 BFPD from 12,000 ft. possible.	Fair; > 200 BFPD from 4000 ft.	Fair; limited by heading and slippage. Avoid unstable flow range. Typically lower limit is 200 BFPD for 2' tubing without heading; 400 BPD for 2.5' and 700 BPD for 3' tubing.	Good; limited by efficiency and economic limit. Typically 1/2 to 4 barrels per cycle with up to 48 cycles per day.	Excellent; for 1 to 2 BFPD with high GLR.