

6 CANADIAN CHOPS PRODUCTION PRACTICES

6.1 *Initiating and Sustaining Sand Influx*

To initiate sand influx, the following completion practices are usually followed in CHOPS well development (Figure 6.1):

- Large-diameter (>20 mm) perforation ports are used.
- Perforation spacing of 26 or 39 shots per metre (more rarely closer spacing) is used, and underbalanced perforating is better than overbalanced.
- In thin formations (<6 m), the entire height is perforated; in thicker formations, 6-8 m of perforations are placed toward the bottom of the pay interval. More rarely, these are placed in the zone of highest production potential (highest kh/μ values).
- Perforations are fully phased regardless of the well inclination or orientation. (CHOPS wells range from 0° to $\sim 45^\circ$ inclination; steeper inclinations are not advised.)
- The progressing cavity (PC) pump is placed with the inlet (the bottom of the 0.5 m long tailpipe) 1-2 m below the lowermost perforation.
- While reservoir compatible fluid is being placed into the annulus, initially keeping it full, the PC pump is started and brought up to a speed that allows sand and oil production to be sustained (50-100 rpm usually, depending on sand cut).
- The annulus fluid addition is ceased or diminished slowly so that the annulus fluid level drops while the pump is operating at full capacity; this generally initiates and maintains sand influx.
- If sand influx does not occur, a series of steps is undertaken to perturb the formation and remold it while the PC pump is in the hole. Such steps may include:
 - Aggressive injection of lighter battery oil into the annulus at a high rate;
 - Rapid injection of 5-10 m³ of heated compatible oil through the annulus.
 - Simultaneous injection through the tubing and the annulus once the rotor is backed out of the stator.

- If attempts at sand initiation fail, the pump is withdrawn from the hole and Chem-Frac™ (a small rocket propellant charge ignited down-hole), pressure pulsing (PPT) , or some other workover method is carried out.

In general, about 85-90% of CHOPS wells come on to production without having to withdraw the pump, and even with the best of techniques, ~5% of wells never successfully achieve sand co-production.⁴⁴

Sustaining sand influx is necessary to produce heavy oil at economic rates. If a mechanical failure or a wellbore or pump blockage by sand occurs, a workover is required (see Chapter 8). Tubular goods are withdrawn, and before reinstallation, the well is thoroughly cleaned of sand using a mechanical bailer, a pump-to-surface truck, a jet pump, foam treatment, or other techniques. Production is reinitiated after pump reinstallation.

However, the loss of sand influx may arise because of a number of processes that take place outside the casing:

- The perforations may be plugged with sand arches, cement fragments, concretions, or fragments of shale.
- Sand may have become recomacted around the well in a dense state so that the gradients available are no longer sufficient to destabilize the sand.
- The well may have become “disconnected” from the far-field source of pressure (dissolved gas in the oil phase), and insufficient flow velocities exist to allow sand flow.
- The overburden may be supported sufficiently by the stable interwell regions so that the gravitational component of the CHOPS drive mechanism is no longer available.
- The reservoir may have reached a depletion state so advanced that the necessary pressure gradients to sustain sand influx are no longer possible.

In these cases, various injection approaches may be used with the pump in the hole (rotor in the stator or rotor backed out), or the pump may be withdrawn and a full workover implemented. It

⁴⁴ Pressure pulsing is a relatively new approach, dating only since early 1999. Used in a workover mode, it has been quite successful as a means of bringing recalcitrant CHOPS wells onto sand production, even after all other techniques have failed. If it is used more systematically, it should increase the proportion of successfully initiated CHOPS wells.

appears that methods that achieve the largest perturbation of the wellbore environment are the most effective at re-establishing sand influx.

6.2 Lifting Approaches

6.2.1 Reciprocating Pumps and Related Devices

Since the 1930's, Husky Oil Company and a number of small oil companies have produced heavy oil in the Lloydminster area using reciprocating pumps with bottom-hole ball-valve pumps driven through sucker rods from the surface with pump jacks (called "donkeys"). These wells generally produced 3-7 m³/day, with a maximum productivity of perhaps 10-12 m³/day in ideal circumstances. In almost all cases, the maximum production rate of the wells was limited by the maximum rod fall velocity.

The problem of rod fall velocity is directly related to the viscosity of the fluids in the production tubing. These fluids generate drag on the sucker rods as they fall, and a retarded pump recharge rate is also generated because the viscous oil must flow through the pump body to recharge the pump cavity on the downstroke. If largely "pure" 10,000 cP oil is being produced with a small amount of sand and less than 5% water cut, as the pump jack moves on its downward stroke, the rods cannot fall any faster than about 0.15-0.25 m/s. This gives a reciprocation rate of about 3-5 strokes per minute, depending on the pump configuration (stroke length), giving a production capacity of less than 10 m³/d. Furthermore, the upstroke requires much more energy than in conventional oils because of the viscous drag on the rods and the generally low annulus pressure (i.e. because the annulus fluid level is low, the pump must "lift" the fluids in the production tubing with little benefit of backpressure from the annular fluids). Given the typical displacement volume in a reciprocating pump designed for a 7" casing, and given the fact that the produced fluids often develop foam at the inlet to the pump, thereby reducing its efficiency, the maximum production rate is generally limited to 7-10 m³/d of fluids. In the case of a well that is deviated at angles > 20°, the problem of slow rod fall is even more severe, and steel erosion more serious.

Is it possible to push down on the sucker rods at the surface? The answer is no; this gives little to no advantage because the rods spiral in the hole ("spaghetti" buckling) and fail to place a downward force on the pump at hole-bottom.

Various patented and field-rigged methods were tried over the years to overcome the problem of low rod fall velocity through some form of spring or energy recharge device (gas piston) at the hole bottom that could pull the pump plunger and the rod string back down at a faster velocity, allowing increased pump speeds. Apparently, none of these methods proved to be sufficiently effective to warrant adoption in the Canadian oil industry, and at present, there are no known applications of such devices.

Several different techniques to provide longer strokes or more uniform lifting power have been developed. In horizontal thermal wells where the elastomer of a PC pump may experience thermal break down, standard reciprocating pump technology is used with no plastic or elastomeric parts. However, several companies have concluded that lifting efficiency is correlated with the length of the stroke in these horizontal wells. Two approaches have been developed for long stroke pumps. Extremely large standard pump jacks, often set at an angle for deviated wells, are used at the Wolf Lake Project (previously BP, then AMOCO, then BP again, now CNRL) to provide a stroke length of 4 m. These have been widely adopted elsewhere for thermal projects such as SAGD implementation.

Alternatively, the RotaFlex system (a Weatherford product) uses a large counterbalanced belt on a tall frame that winds and unwinds, giving a long stroke (~6 m) to a conventional bottomhole reciprocating pump apparatus driven by sucker rods (Figure 6.2).

In the 1980's in Canada, several hundred High-Efficiency Pump (HEP) units were sold. These devices used a small hydraulic power source, hydraulic lift and a gas pressure accumulator to store part of the energy on the downstroke of the drive rods in the tubing. The units used electronic control methods on the stroke limits and could be almost infinitely programmed in terms of stroke length and speed. Claims of greater energy efficiency notwithstanding, these devices were gradually abandoned. By the latter half of the 1990's, no HEP units were operating in the heavy oil industry in Canada. In large part, the HEP system was displaced by the rapid development of PC pump technology during 1982-1995.

6.2.2 Continuous Sand Extraction CSE Pump⁴⁵

A device developed in Lloydminster for “pumping” packed sand of 35-50% porosity from wells was developed in the 1990s. The Continuous Sand Extraction pump is a 3 m stroke piston pump lowered on the bottom of tubing. It is used as an alternative to a mechanical bailer and other devices to clean sand from the hole, or to cope with periods of extremely high sand influx (>40% sand) with no free gas in the incoming fluid, where even a PC pump will have difficulties.

Reciprocating the tubing actuates the CSE pump cylinder and piston at hole bottom so that a thick slurry or even “solid” sand can be drawn up into the body of the pump while the dense sand in the tubing above the pump is displaced upward. Continued stroking of the CSE pump results in a large column of sand, and in cases where there is a high annular fluid level so that Δp is not excessive, the sand can be directly pumped to surface. If the sand cannot be pumped to surface easily, it is also possible to feed viscous oil into the annulus to promote the dilution of the sand in the wellbore and allow easier inflow to the CSE pump. If no fluid is trickled into the annulus, the CSE pump will draw down the annular level until the Δp between the wellbore and the formation is large, and this promotes sand influx.

Typically, a CSE unit will be used for the period of a CHOPS well when the sand content is high, so that a PC pump will not have to contend with sand concentrations combined with the possibility of steel fragments or perforation charge fragments that could damage the elastomer. Once the sand content drops below ~10%, the low capacity CSE pump can be replaced with a higher capacity PC pump.

6.2.3 Jet Pump Development and Use

PanCanadian Petroleum has carried out research into jet pump lifting systems for approximately a decade. Jet pumps have been tried repeatedly in Canada, and are widely used in one form or another for hole cleaning functions, powered by a pump-to-surface unit or similar high rate pumping system. However, they have never found use in CHOPS well production as a long-term lifting system. The reasons for this have never been made public, but it can be speculated that the problems of lifting capacity, internal erosion of the steel in the jet impingement area, and

⁴⁵ Website www.kirbyhayes.com contains information on the CSE pump, as well as many other links and much relevant information for the CHOPS industry.

the generation of difficult emulsions (well dispersed because of the high shear in the jet throat area) were responsible.

In the absence of published data, it is difficult to say precisely which were the most important issues that caused jet pump technology to fail, but there are some logical suppositions that are worthy of comment. In particular, developing CHOPS well production schemes to take advantage of the large fluid rate increases that accompany sand ingress means that the production engineer must design operations to cope with high-early sand influx, perhaps as high as 15-20% of the total fluid volumes entering the pump inlet at depth. (Furthermore, continued sand influx over time, perhaps for 10-15 years, must be accommodated in the design.) The early high sand content conditions are triggered and maintained by aggressive drawdown of the annular fluids, so that a large Δp between the wellbore and the reservoir is required. Aggressive drawdown also means that the gas content (in the form of foam) at the hole bottom in the fluid flowing to the pump intake can be large. If there are low pressures in the jet orifice region, this gas can expand suddenly, reducing pump efficiency.

In the case of a jet pump, a large drawdown increases the energy requirements substantially, and high liquid jet velocities are needed to achieve lifting capacities of 10-30 m³/d of reservoir fluids against a fluid head difference as large as 600 m in wells that are 650-700 m deep. This lifting requires maintenance of a Δp of about 5.5-6 MPa, and it cannot be done with jetting viscous oil through the pump, nor is it economical to use diluent; therefore, water must be used as the jetting agent. The water carrying the motive power has to be free of abrasive solids because it passes through a small constrictive nozzle at the tip of the jet to build velocity. This means that it is difficult to economically recycle water separated from the fluids production stream because the water becomes contaminated with clays and silt, leading to rigorous filtration requirements at the surface for water recycling.

The shear energy required to accelerate the wellbore fluids so that lifting can occur requires high water velocity and reasonable water rates. Once the water has left the jet nozzle, it can entrain sand and abrade the outer body of the jet pump. Adding water reduces the viscosity of the fluid, and therefore reduces the dampening effect that the high viscosity has on the momentum transfer responsible for abrasion. To keep abrasion to a minimum, it is best to keep viscosity as high as possible and velocity as low as possible. Jet pumps fail on both counts.

Along with the clay minerals and polar (generally asphaltene) molecules in the heavy oil, the high shear rate of a jet pump also is ideal for the generation of emulsions (emulsions such as salad dressing are created by high shear, and the presence of polar molecules). Furthermore, many CHOPS wells produce reservoir fluids with less than 10% water for many years, and much of this water separates easily at the surface in the heated stocktanks. With a jet pump, the motive power must be water, and the addition of substantial amounts of water entailed by a jet pump leads to additional separation difficulties and costs at the surface.

6.3 Progressing Cavity Pumps

6.3.1 Evolution of PC Pump Use in Canadian Heavy Oil

In the 1920's, a French university professor, René Moineau, developed the concept of an eccentric helical rotor turning in an external stator, also with a helical hole but actually consisting of two helices together (Figure 6.3). If the elastomer in the stator has an "interference" fit with the smooth surface of the rotor, a series of fully isolated cavities progresses along the length of the rotor-stator system as the pump operates. In contrast to an Archimedes screw, the pump developed by Professor Moineau moves fluid in fully isolated cavities in any direction, even downward. The concept is used for mud motors that rotate the drill bit at the bottom of the hole during drilling, particularly in highly deviated and horizontal wells. Because the sealed cavities progress along the pump body between the stator and rotor, the term Progressing Cavity pump, or PC pump, is used.

Moyno Company in the UK developed and marketed PC pumps for years on the basis of the original patent, gradually improving them. Initially, pumps were plagued by inadequate elastomer quality, giving short life in severe usage conditions (e.g. high sand contents). Elastomer deterioration in the presence of polyaromatic compounds leads to insufficient seal at contact points to give high rates at reasonable Δp values across the pump. Better elastomers developed in the 1970's, rigorous quality control in the injection molding of the stators, precision welding of stator sections, and elimination of heat damage to elastomers resulted in improved pump quality and capability.

The first PC pumps in heavy oil were tried in California in the 1960s and 70s, in cases where sand content was extremely small. They were introduced to the Canadian HOB in the early

1980's. These early designs had short life spans (~3-6 months), and there was little confidence in their ability to operate under the demanding conditions of sand influx, particularly with the large sand cuts at the beginning of production. Nevertheless, based on some experiences where pumps lasted reasonably well, and also because they overcame the rate limitation associated with slow rod fall in reciprocating pumps, PC pumps continued to be tried by various small operating companies. The most important factor was that these pumps often could double and triple well production rates, and even though margins for heavy oil were slim, this greatly affected profitability.

Continued development work and improved quality control on the stator molding resulted in gradually improving quality, capacities, and life spans for PC pumps. For example, of several original world manufacturing sites for the injection-molded stators (Seepex GmbH, Germany; Moyno in Britain, web site www.moyno.com, etc.), the quality and life span of the stator varied considerably, and this caused difficulties such as premature elastomer ripping or embrittlement. Competition has led to improvement in the products of all the PC pump companies, but there are some manufacturers in China and elsewhere that still have poor track records. In general, the problems include poor quality control (e.g. insufficient capacity for the injection-molding system resulting in small cavities that generate failure points), and chemical incompatibility with the fluids being pumped (e.g. insufficient resistance to high molecular weight aromatics).

Currently, better quality control and more manufacturing sites around the world continue to improve the performance and lifespan of PC pumps. A decade after the first introduction in Canada in 1982, PC pumps became widely accepted as the standard for CHOPS wells. They are now available for a wide range of capacities for many different conditions. PC pumps with capacities as large as 1000 m³/d with 2500 m lift capacities are available for conventional light oil. For lifting of gassy heavy oil and sand slurries, pump life has been extended from 6-8 months to 15-20 months, and a wide variety of capacities and sizes are available. For CHOPS applications, the maximum volumetric rates are 70 m³/d/100 rpm, and the Δp lift capacity tends to be approximately 800-1200 m, with lower capacities for shallower wells (some slow wells may use pumps as low as 7 m³/d/100 rpm).

There are a number of "independent companies" providing PC pumps, but many of them purchase their components from the same suppliers who have perfected the methods of high

quality stator elastomer injection. The two largest companies in Canada are Weatherford-BMW (EVI) and Kudu Pumps, but other suppliers are providing PC pumps for heavy oil wells in addition to specialized devices such as surface transfer pumps for slurries and viscous oil.

6.3.2 Current PC Pump Practice in the HOB

Since the early 1990's, new CHOPS wells coming onto production in the HOB not only use PC pumps almost exclusively, but also use only those developed in the Lloydminster area, as these are designed to provide the necessary resistance to sand in the fluid. If a workover is done on an old CHOPS well to increase productivity, usually the reciprocating pump is removed and a PC pump installed.

A relatively standard configuration for a new CHOPS well is a PC pump 6 –10 m long with a Δp capacity of 1000 m of differential lift, designed at a stator-rotor pitch to give a production rate of between 10 and 50 m³/100 rpm. The details as to the pitch, eccentricity, and other design parameters depend on the expectations of the producing company and various well factors such as viscosity, expected annular fluid level drawdown, gas content, and so on. Many companies use a software program developed by the Canadian Centre for Frontier Engineering Research (C-FER, now part of the Alberta Research Council) to allow easy choice of the optimum PC pump for particular applications.

The advantages of PC pumps for heavy oil lifting in CHOPS well configurations are the following:

- A PC pump can lift the high viscosity fluids with large solids concentration that are produced during CHOPS initiation. Sand cuts up to 45-50% of the dead fluids can be lifted (remember that foamy gas behavior reduces the volumetric sand concentration entering the well, allowing the slurry to behave as a compressible fluid).
- The PC configuration can operate under conditions of substantial gas volumes, as long as the gas is in the form of foam, and not as large gas slugs (heat build-up is an issue if the pumps operate for any substantial time with free gas).

- A PC pump has low internal fluid shear rate because the pump physically lifts the fluid in each cavity (the fluid moves up the pump body with little rotation, in contrast to a centrifugal pump). This low shear rate limits fluid emulsification problems.
- The low fluid velocities in the PC pump mean that steel erosion is not an issue, although some abrasion of the rotor invariably takes place.
- There are no valves to clog or gas lock, as in some other types of pumps.
- In general, a PC pump has relatively low capital costs and power costs.
- The low wellhead profile associated with the rotary drive units, particularly the new hydraulic drive units, gives less visual “disturbance” or clutter at multiple well pads, and allows more effective placement of wells a smaller surface footprint for multiple well pads, and greater ease in maintenance and changeouts (compared to a large pump jack for example).

There are some disadvantages that must be kept in mind when operating PC pumps in CHOPS wells:

- A rapid failure rate occurs if the pump is allowed to run dry. This may arise because of excessive annular fluid drawdown or because a large gas cap generates a prolonged gas slug; and,
- There is a tendency for elastomer ripping if a pebble or a piece of metal enters the pump.

A number of recent developments in PC pump design have been triggered by the unique demands of the Canadian heavy oil industry and CHOPS approaches, and these should be mentioned.

6.3.3 “Sloppy-fit” PC Pumps

PC pump efficiency is determined with water pump tests in the factory, using manufacturers’ criteria. In the early 1990’s it was recognized that PC pumps retained a high efficiency (>80%) for pumping viscous heavy oil despite substantial rotor wear from sand abrasion that destroyed the interference fit. When worn pumps were tested with pure water, efficiencies of only 10-30% were found because of fluid slip between the rotor and stator (slip depends on viscosity, efficacy of the rotor-stator interference fit, and the number of cavities per metre). Now, PC pump

manufacturers offer sloppy-fit pumps for CHOPS applications, recognizing that using a tight-fit pump will result in abrasion of the leading edges of the rotors after a few months of use, leading to a “sloppy fit” in any case. An initial sloppy fit prolongs rotor life, and permits rotors to be resurfaced and reused several times.

6.3.4 Charge Pumps

Conventional PC pumps discharge all their fluids directly into the production tubing. PC charge pumps have two sections; the lower one operates at a higher flow rate than the upper one at the same rpm because the rotor/stator pitch is longer. Bypass ports in the stator at the junction of the two sections allow the excess fluid to be expelled into the annulus, and provide “charge fluid” to the upper pump at a somewhat elevated pressure. Thus, Δp requirements across the upper pump are reduced and the gas bubbles in the produced fluid are partially compressed. This increases the efficiency of the upper PC pump stage. Also, the fluid that is bypassed apparently has some beneficial effects on wellbore performance. The recirculation of part of the fluid back down the annulus across the perforations tends to homogenize the pump intake fluid, reducing chances of pump blockage by sudden sand slug influx, and perhaps reducing somewhat the negative effects of a large gas slug. Also, blockage tendencies because of sand arching in the annulus between the pump stator and the casing are apparently reduced (a typical 4.2” PC pump diameter gives a total annulus of 70 mm for 7” casing, 33 mm for 5½” casing, but small diameter casings are no longer used because of well workover difficulties).

6.3.5 Constant Elastomer Thickness PC Pumps

Differential heating of the stator elastomer during PC pump operation arises because of different elastomer thickness (Figure 6.3), leading to varying heat dissipation capacities along the stator body. If there is heating during pumping, this differential thickness leads to differential thermal expansion, which in turn leads to increased heating of the expanded sections, exacerbating the problem, leading to elastomer embrittlement, deterioration, and ripping. To counteract this, the three-lobe stator PC pump was developed; this configuration provides an elastomer that has less thickness variation around the stator diameter (Figure 6.4). Apparently, in a number of service conditions, the three-lobe stator configuration also is a more efficient fluid lifter. However, it has not been widely adopted at the present time for CHOPS wells.

A helicoidal external stator housing (the steel casing containing the elastomer) that reflects the helix-like curvature of the interior of the stator was introduced in 1998-99. This design means that the elastomer can be pressure injected into the stator housing and achieve an almost constant thickness. This constant thickness virtually eliminates the problem of differential thermal expansion. This configuration comprises a small percentage of PC pumps, but some operators believe it helps prolong pump life in some fields and are therefore adopting it more widely, despite somewhat higher cost.

6.3.6 Rotor Wear

The leading edges of the PC pump rotors are subject to the greatest wear rate from sand abrasion. To reduce the wear rate and maintain pump efficiency, the technique of boronizing the rotors was developed (rotors can also be chromed, and even re-chromed). In general, this can be expected to increase pump rotor life by 10-30%, perhaps more in the case of abrasive sand. It must be remembered that there are many reasons for pump breakdown other than rotor wear, and many PC pump rotors are changed routinely when a workover is performed.

In addition to more resistant coating on the rotor, the advent of sloppy-fit PC pumps has reduced the rate of rotor wear and the frequency of rotor replacement.

6.3.7 Downhole Drives for PC Pumps

Downhole drive approaches to PC pump operation are intended to replace the surface rod-driven method that is the current industry standard. Electrical and hydraulic downhole drive PC pump approaches have been pursued for over a decade; there are currently approximately 50 to 100 of each of these types of pumps operating worldwide to produce heavy oil, but not with the high sand cuts typical of Canadian production from CHOPS wells.

The Electric Submersible PC Pump (ESPCP) is available through several companies; Baker-Hughes-Inteq is one of the largest suppliers. It has not had a good record of durability, and the units are expensive, compared to rod-driven PC pumps. Several attempts have been made to install these pumps in Alberta CHOPS wells, but ESPCP devices do not cope well with large quantities of sand. The research arm of the Venezuelan national petroleum company, Petroleos

de Venezuela, has had an active research and development program for some years into ESPCP use in heavy oils, and monitoring the progress of this and related activity is worthwhile.

The Hydraulic Submersible PC Pump (HSPCP) is newer than the ESPCP, and there is little track record yet for its durability (visit website www.petrospeceng.com for additional updates). The HSPCP requires two hydraulic lines from the surface to the drive unit above the pump in addition to the usual crude oil production tubing; as a result installation and servicing are more expensive.

Development of a PC pump that is driven by rotation of the tubing string itself, without a drive rod string inside the tubing, using a bearing attachment joint between the PC Pump stator and the tubing to drive the rotor, has been tried and may still be under development at this time. The advantages of such a system are:

- Simpler workovers, as only the tubing and the pump have to be withdrawn, saving a rod string trip.
- No internal impediments in the tubing to the upward flow of the oil-sand slurry, thereby reducing flow resistance and eliminating sand-induced wear between the casing and the drive rods.
- Direct installation of the PC pump pre-assembled with the rotor in place in the body is feasible, rather than introducing the rotor after stator anchoring by carefully lowering the rod string until the stator bottom touches the “tag bar” in the bottom of the tailpipe.

However, rotating the tubing string means that the issue of wear between the casing and the tubing must be carefully addressed because breaching the casing with rotating tubing is more serious and much more expensive to rectify than tubing string breaching by drive rod abrasion. Of course, casing steel thickness is larger than tubing thickness, and there is no sand moving up the casing-tubing annulus, as there is in the interior tubing-rods annulus during conventional PC pump operation. Thus, wear rates should be low, and protective measures such as nylon wear sleeve installation can be undertaken to protect the casing and the tubing joints from wear.

Alternatively, smaller diameter continuous (coiled) tubing may be used instead of 3½” tubing, avoiding the wear points associated with tubing collars.

Both ESPCP and HSPCP technologies should eventually prove to be better for wells with high deviations or short-radius turns, as the problem of rod wear of production tubing is eliminated. Petrovera Energy Resources has an active development program for HSPCP use in Alberta, but no details of long-term reliability and overall economic benefits have yet been released. The development of hydraulic submersible drive PC pumps is a technology evolution area to monitor over the next 10-15 years to see whether the apparent benefits of down-hole drive methods can bring greater economies and reliability to CHOPS wells.

6.4 PC Bottom Hole Configuration and Operational Management

6.4.1 PC Pump Bottom-Hole Installation

A typical PC pump downhole installation is shown in Figure 6.5. The major features of the installation are listed here:

- CHOPS wells usually are drilled and cased 2 to 4 joints deeper than the pump seating location to provide some buffer for the early massive sand influx that occurs during start-up.
- 7" casing in a 9" hole is standard, although some companies have experimented for years with 5½" casing in a 7" borehole. The smaller dimension casing has not been widely adopted for several reasons (e.g. difficulty in finding workover equipment of appropriate size and casing distortion trapping the PC pump in the hole).
- A typical PC pump is ~4.25" OD, installed on 3½" or 4½" tubing, depending on the torque magnitude expected. Early in the PC pump history, 2⅞" tubing was common, but restricted flow and low torque resistance caused this approach to be abandoned for new CHOPS well applications.
- The stator is driven with a standard sucker rod string or a continuous rod (Corod) string operating within the tubing. Some field operators have tried elliptical rods to achieve higher torque without impeding the flow in the tubing. Special nylon sleeves and other devices are used to reduce sucker rod coupling wear or tubing wear in doglegs or where the couplings contact the tubing.

- The bottom of the stator is fitted with a tailpipe that serves as an inlet. If the rotor extends below the bottom of the stator, it will rotate freely within the tailpipe. Various tailpipe designs have been suggested to homogenize the fluid feeding the pump intake, with little apparent advantage among different designs. A 0.5 m long tailpipe with several 10-12 mm wide vertical slots is a common design, and a horizontal cylinder (~6 mm) of metal, the “tag bar”, is welded across the bottom of the tailpipe to serve as a firm location that can be tagged when lowering the rotor, and also to catch the rotor if rod twist-off should occur, hence saving a fishing trip.
- The inlet of the pump, or the highest inlet port on the tailpipe, is set at least 1 m below the lowest perforation opening to allow some flow path in the annulus to help homogenize the pump feed. If the pump is placed higher in the hole, the lower perforations will become blocked with sand settling in the casing, rendering them ineffective in providing slurry to the wellbore, and reducing reservoir access.
- A “no-turn” tool or torque anchor is installed to prevent the tubing from backing off during rod rotation. This no-turn tool was originally installed at the top of the stator in the intact casing section, but in the last few years, operators have placed the torque anchor at the bottom of the stator (just above the tailpipe) in order to increase the amount of gas escaping unimpeded up the annulus, with seemingly acceptable results (i.e. no substantial increase in well plugging). In such cases, the anchor must allow for relatively free passage of the oil-sand slurry down through it to the tailpipe.

6.4.2 Surface Drives

The surface drive system for PC pumps consists of an electrical-mechanical drive or a hydraulic-mechanical drive using a hydraulic unit that can be powered either electrically or with an HC engine (diesel, natural gas). Both of these power systems turn a set of gears or large sheaves that are coupled to the drive rods through a clamped connection. Which approach is taken depends in part on the number of wells on a single pad. If the site has one CHOPS well and electricity is locally available, electrical drive is the likely choice. In remote locations with multiple wells on one pad, a central hydraulic power unit may be preferable.

A new development from Corlac⁴⁶ in Lloydminster in 2001 is a direct surface hydraulic drive that eliminates the sheaves, belts, and gears that are used in the other approaches. The new drive unit is extremely compact, only 0.3 m in diameter and 0.6 m long, and it is believed that it will receive wide acceptance in the industry in years to come. It requires high pressure hydraulic oil supply from a separate prime mover.

New PC pump surface drive units are equipped with automatic torque controls and computer-managed optimization, including programmable shutdown criteria to avoid pump loss if pumping conditions deteriorate.⁴⁷

6.4.3 PC Pump Operation in a New CHOPS Well

The details of PC pump operation during start-up vary from company to company, but there is a generally accepted set of practices followed in the heavy oil industry to cope with the large sand cuts typical of early production in new CHOPS wells. A few of these guidelines are listed below:

- During start-up of a new CHOPS well, annular fluid is usually added to allow the full system to achieve momentum, then the annular fluid level is allowed to drop gradually, and formation fluids are produced in an increasing proportion as the input annulus fluid volumes are diminished.
- Generally, the more viscous the oil, the slower the rotational speed; 10,000 cP oil is usually produced at 50-80 rpm, 500 cP oil at 200-250 rpm (light oils at 300 rpm). If higher production rates are desired because the well is exceeding expectations, a larger pump is installed. During the initial start up with high sand cuts, rotational speeds are even lower because of high torque requirements.
- As time goes on, the tubing may be lifted and turned between 40° and 90° on a regular schedule (several months) to minimize concentrated wear on the tubing. The seating depth of the rotor vis-à-vis the stator is changed regularly for the same reason.

⁴⁶ Website <http://www.corlac.com/> should be visited for more information.

⁴⁷ For example, recent developments in downhole instrumentation provide direct read-out of the fluid pressure in the annulus, allowing the PC pump operation to be simultaneously optimised on torque, rate and annular fluid level.

- In general, the annular fluid level in the well is not dropped to extremely low levels. Many field operators use values between 5 and 10 casing joints (50-100 m), but with the advent of downhole pressure gauges, field operators are tending to use lower annular fluid levels, normally two to three joints. The lower the annular fluid level, the greater the drawdown on the well, and the greater the well production capacity. However, the risk of too low a level is substantial in a well that does not have a BHP gauge, as a period of gas throughput will almost invariably ruin the stator elastomer.

6.4.4 PC Pump Rates, Sand Tolerance

With the developments mentioned previously, there are few constraints on PC pump rates in most practical situations. If the fluid is of low viscosity, a PC pump should be able to operate continuously at 250-300 rpm, achieving a displacement efficiency of > 90% indefinitely.

However, PC pump performance is degraded in a number of situations, leading to practical rate limitations:

- During the early CHOPS period when sand production rates are high, the viscosity limitations restrict rotor speed to values as low as 30-50 rpm.
- As PC pumps are being used in deeper wells with large reservoir drawdown values, limits of efficiency are being challenged, and keeping fluid slip (fluids bypassing the stator-rotor seal) low is difficult in cases of sand production and high Δp values across the pump. In such cases, longer pumps with a larger number of rotor turns are used to achieve about the same Δp across each rotor cycle as for shallower pumps, thereby maintaining reasonable fluid slip levels.
- In long inclined CHOPS wells ($>30^\circ$) producing fluid containing sand, abrasion is high and speed is limited by wall friction, even with special measures.
- Sand settling out of the fluid in the production tubing on top of the PC pump can occur in some situations (e.g. power shut-down, water influx). The sand settling velocity in the viscous fluid can be estimated only poorly with a Stokian settlement assumption. Some of the challenges arising in computing a settlement velocity include:

- Typically, there is a range of sand grain sizes over a factor of two in diameter (e.g. from 100 to 200 μm in size), leading to a factor of 16 in different settling velocities; larger particles settle much faster.
- The composition of the fluid being produced (an oil-water-sand-gas slurry) is not constant: CHOPS wells show variability in phase composition over short time intervals. Over a period of seconds, sand content can rise from 2% to 10%, then gradually drop back to 2-3%. The need for on-line torque control is evident.
- The viscosity of a multiphase fluid is notoriously difficult to measure, particularly if there is an appreciable volume fraction of gas bubbles and sand grains.
- During settlement of a heterogeneous mixture of grains of different diameters in a long vertical tube, grain pile-up occurs, and this interferes with the settling rate of individual grains (i.e. the Stokian assumption of no interaction among grains is violated).
- In an inclined tube with an immobile sucker rod, friction along the wall and inclined metal surfaces impedes settlement.
- In general, the actual composition of the fluid in the tubing at the time of a shutdown is not known.
- In many practical situations, the sand settlement velocities are slow enough and the sand concentrations low enough that it is possible to restart the PC pump even after many hours of shutdown.
- Sand blockage becomes more likely as the CHOPS well produces more and more water in the fluid. There is a widely held view in the conventional oil industry that sudden sand influx accompanies rapid water breakthrough because of the reduction of capillarity with multiphase state changes.^{lvi} In CHOPS wells, this is not the case, but a sudden increase in water cut (and of course gas content at the same time) can rapidly increase settlement velocity so that a shutdown leads more rapidly to pump blockage and need for a workover.
- Finally, the major reason for premature PC pump breakdown historically apparently has been allowing the pump to operate without liquid intake (i.e. gas or air only). This

problem is being eliminated with continuous BHP monitoring that will eventually become standard.

6.4.5 PC Pumps as Surface Transfer Pumps

Progressing cavity pumps are being used more frequently as surface transfer pumps for fluids that have varying amounts of solids and different fluids. These PC pumps are horizontally mounted, generally no more than 1.5 to 2 m in length, and almost always hydraulically driven. They are used, for example, as back-up slurry pumps on sand injection systems to clean out the system if a general pump failure takes place. PC pumps are not used where high-volume, low-pressure fluids are to be moved (centrifugal pumps are generally used for this purpose). Similarly, high-volume, high-pressure pumps are almost exclusively piston and cylinder pumps (triplex or quadruplex pumps).

The acceptance of PC pumps as surface transfer pumps speaks for their reliability under adverse conditions such as the need to pump abrasive fluids and heterogeneous mixtures than have large swings in composition over short time periods. They provide easy transfer of difficult slurries at moderate rates and moderate pressures for long periods of time before rotors require replacement.

6.5 Sand Transport and Erosion

6.5.1 Erosion Problems in Tubulars and Wellheads

Erosion problems are common when conventional oil or gas wells experience solids influx.⁴⁸ In these cases, erosion can occur downhole as casing, screen, or tubing wear when sand enters perforation ports at relatively high velocity. Higher in the hole, erosion can occur at the chokes, in the surface facilities and flowlines, and even in the separator. Recently, new designs of wellhead and surface flow facilities have been taking place as field operators begin to recognize the positive benefits of sand influx on well productivity and reliability.

In heavy oil, sand erosion issues do not arise in practice for a number of interrelated reasons:

⁴⁸ One may differentiate between erosion (momentum-induced wear) and abrasion (contact-induced wear with no velocity component of the active agent).

- The flow velocities in CHOPS wells are generally extremely modest, so that sand grain momentum is low, compared, for example, with the high velocities that may be found in natural gas wells.
- The viscosity of the slurry of oil, water, sand and gas bubbles entering the wellbore at depth serves to dampen any inertial effects that might cause erosion at a 90° junction or a tee.
- The temperature is around 15-35°C for the oil produced in Canada, so there are no related high temperature effects that could aid erosion.
- The presence of gas bubbles in the liquid when it reaches the wellhead is sufficient to make the produced fluid highly compressible, hence less erosive.
- Once at the surface, the heavy oil slurry flows only as far as the stocktank, and this is generally less than 20 m from the wellhead.

Abrasion problems do develop in the production tubing because the spinning drive rods trap sand particles against the tubing wall, abrading the wall and abrading the coupling as well. Tubing life is therefore substantially shorter than in a conventional oil well, and to extend the life of a tubing string, it is rotated regularly to reduce excessive single-point wear. If the drive rods have couplings (as opposed to continuous drive rods), the location of the rotor is changed regularly so that the drive rod joints do not act against a single spot on the tubing for too long. Finally, special plastic sleeves are placed along the drive rods to reduce tubing wear near joints, or in zones where the curvature of the wellbore is substantial.

6.5.2 Sand Transport in Flowlines

In addition to a lack of erosion, except for abrasive wear in the production tubing, there appear to be few incidents of flowline plugging in CHOPS production in Canada. The reasons are similar to those that inhibit erosion. The Stokian particle-settling velocity is so low in viscous foamy fluids in low pressure flowlines that no density waves develop, even in wells with flow rates as low as 2-4 m³/d. The sand concentration is typically 2-6%, so that if a shutdown occurs, the CHOPS surface facilities will not plug, and any sand that settles on the bottom of a flow line is

easily re-suspended by viscous drag once flow resumes. Only when sand concentrations are above 20-25% are shutdowns more common because of flow-line blockage.

There have, however, been well blockage problems that have arisen in long horizontal wells in which CHOPS was attempted⁴⁹. These appear to be related to the extremely slow fluid velocities in the region of the toe, combined with a wellbore that has differences in elevation, so that sand can settle in a valley and eventually block the slow flow from the toe.

⁴⁹ There are currently no known successful horizontal CHOPS wells in Canada. Some lower-viscosity oils are produced through slotted liners in long horizontal wells with minor amounts of sand influx, but only with fine-grained sand in amounts less than 0.5%.

Figure 6.1: A CHOPS Well Completion

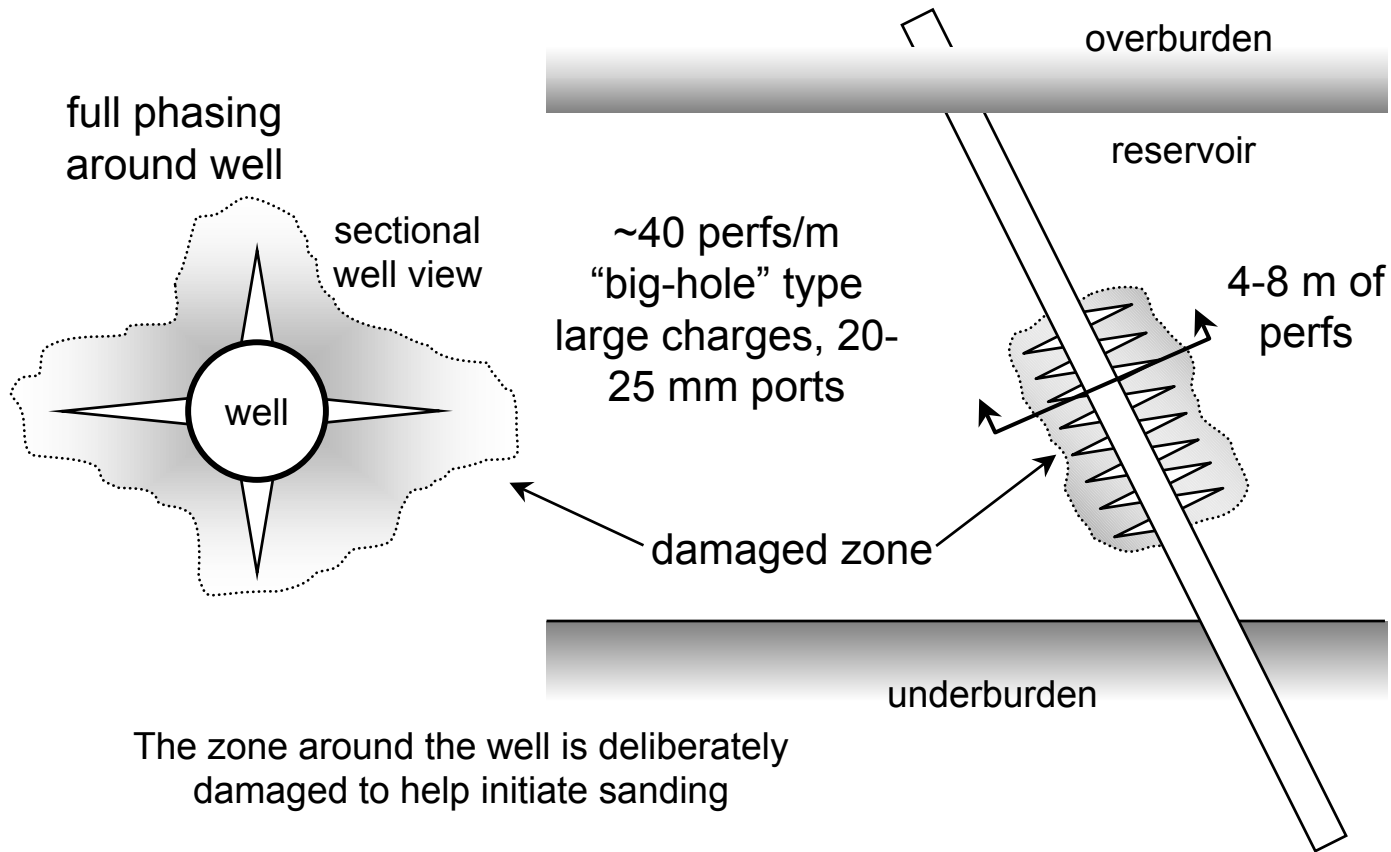


Figure 6.2: The Rotaflex Reciprocating Pump

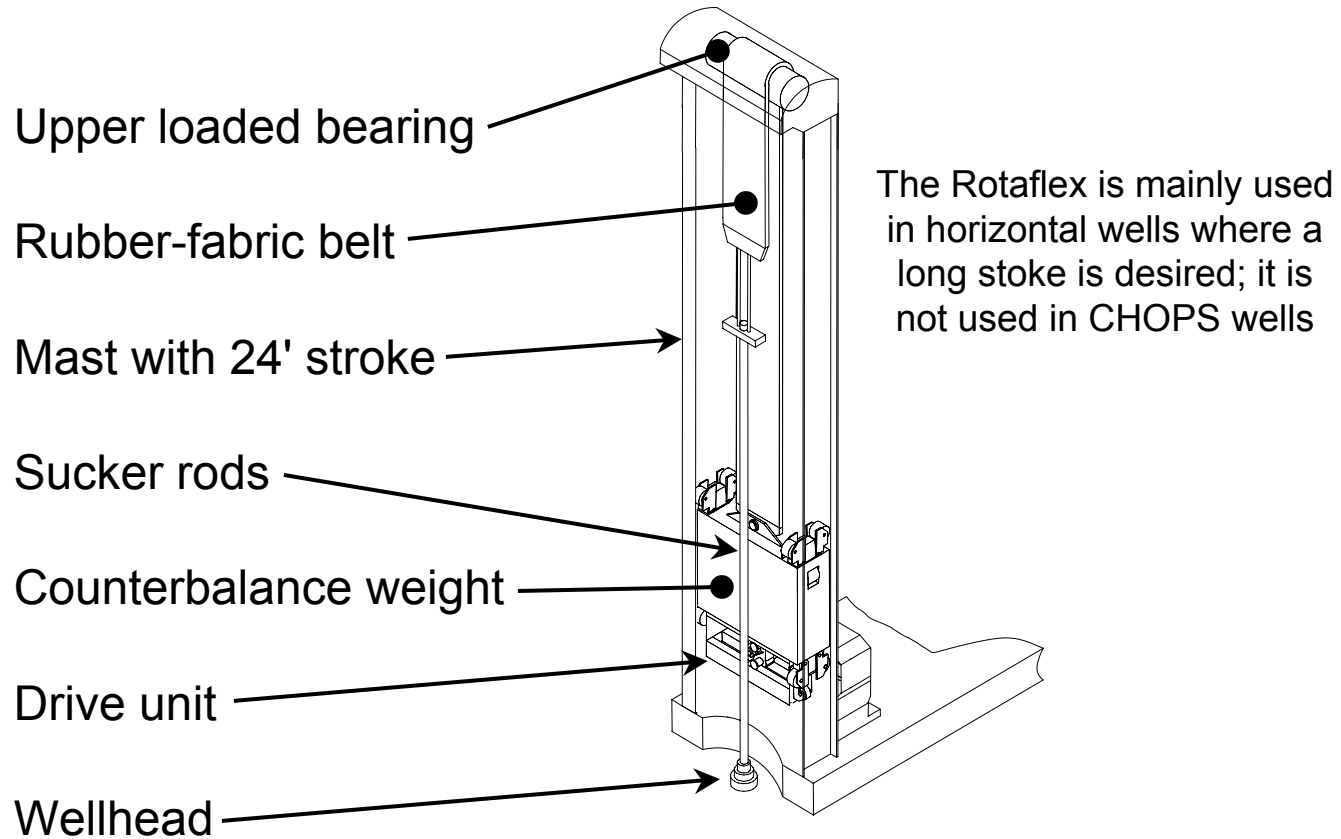


Figure 6.3: The Geometry of a Progressing Cavity Pump (Double-Lobe Stator)

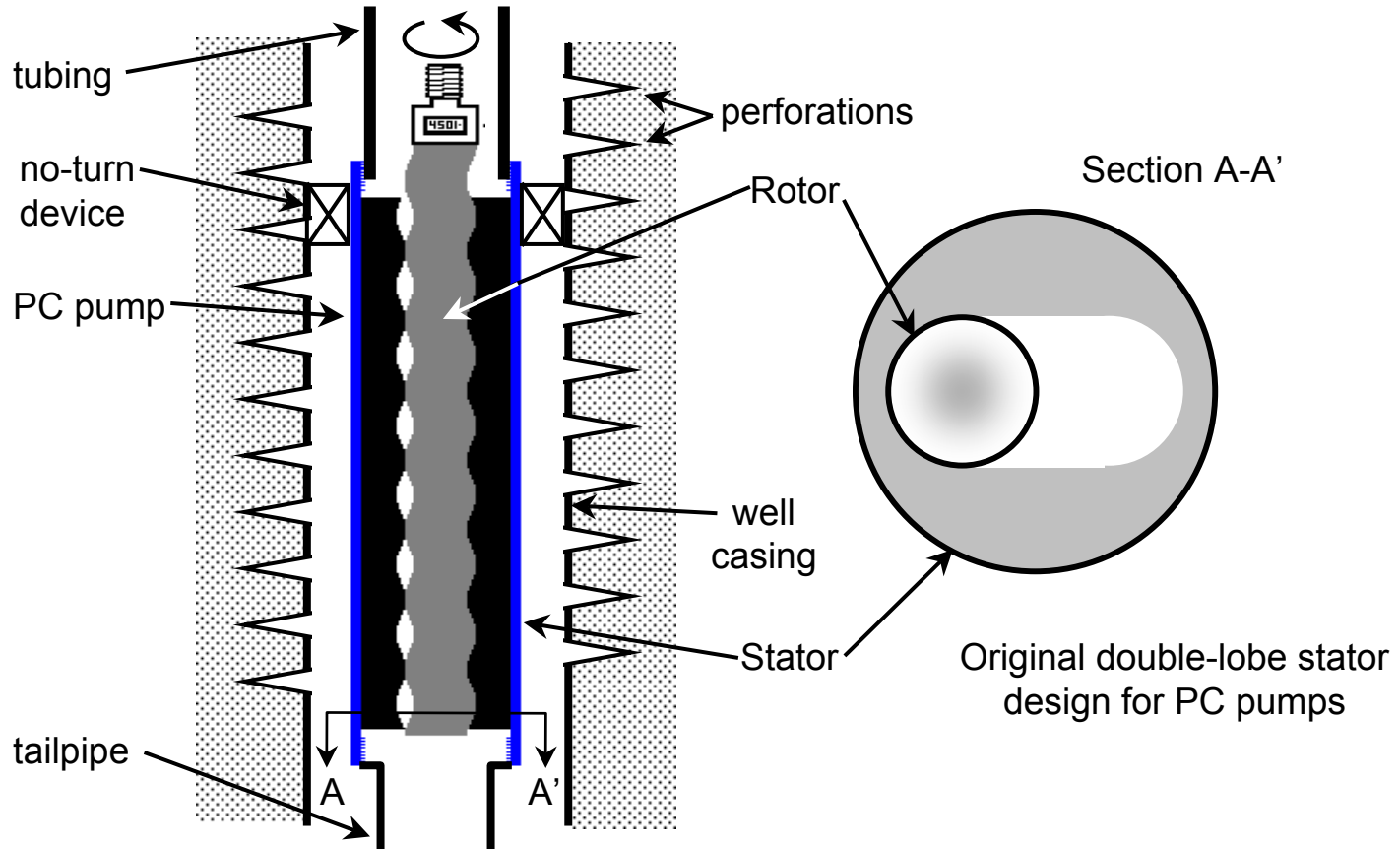
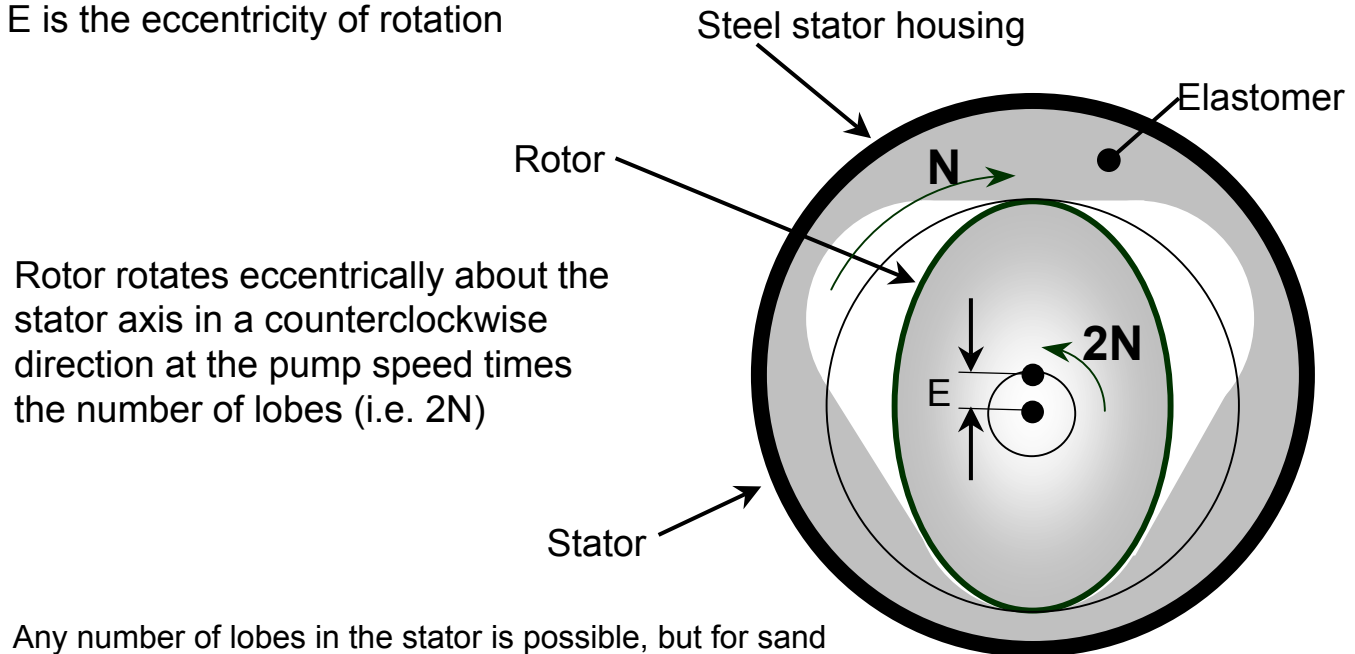


Figure 6.4: Stator Geometry for the Modified Triple-Lobed Rotor

E is the eccentricity of rotation



Rotor rotates eccentrically about the stator axis in a counterclockwise direction at the pump speed times the number of lobes (i.e. $2N$)

Any number of lobes in the stator is possible, but for sand handling, more than three lobes appears to be impractical

Figure 6.5: Detailed Well Completion and Perforation Approach for CHOP Wells

