Findings from the Industry Standard Practice Assessment For Artificial Lift Pump Control Technologies

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For

California Public Utilities Commission

This report details the results for work performed by Itron, Inc. in connection with the California Public Utilities Commission (CPUC) funded Industry Standard Practice (ISP) study for artificial lift pump control technologies installed on new and recently drilled oil wells in California. The industry standard practice (ISP) assessment report is the result of surveys fielded to oil field operators, pump control technology manufacturers, and industry consultants. Special thanks to Nikhil Gandhi (Strategic Energy Technologies, Inc. – consultant to the CPUC) for his participation and valuable guidance.

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1. Introduction

An investor-owned utility (IOU) asserted[1] that on about 30 percent of new oil wells that use rod beam pumps, the operators cannot use any *ON/OFF* controls, specifically, pump-off controllers (POCs) for controlling the pump operation. Typically such new oil wells produce heavy crude under steam flood conditions, and might experience sanding and sticking problems if pumped off. The IOU claimed that POCs are not a viable control option because pumping off (shut downs) an oil well with a POC would adversely affect production operations In such cases rod beam pumps would have to be operated continuously (baseline). POCs were found to be the norm for new rod-beam operated oil wells in a study the energy division (ED) of the CPUC conducted as part of the evaluation of the 2006-2008 program cycle. The IOU proposed that continuously operated oil wells, not POC-controlled oil wells, should be the baseline, and suggested installing variable speed drives (VSDs) as an energy-efficient measure. ED believed that discarding previously established industry standard practice (ISP) of using POCs on rod beam pumps installed in new oil wells would not be appropriate without further research into the applicability of POCs for special operating conditions the IOU cited. Therefore, a study was initiated to establish/reaffirm ISP for controlling rod beam pumps in new oil wells. Due to a recent surge in incentive applications for installation of variable speed drives to control other type of pumps used in new oil wells, ED expanded the scope of research to assess the ISP for all artificial lift pump control technologies, not just those used for rod beam pumps.

The study, conducted by Itron, Inc. on behalf of the ED, featured interviews of oil producers, pump control technology manufacturers and industry consultants. Interviewees included users and experts on artificial lift well pumping and pump control mechanisms typically used for operation of rod-beam pumps, electric submersible pumps (ESPs), and progressing cavity pumps (PCPs). The interview questions investigated the use of VSDs, POCs, throttling valve, continuous operation without controls, and other controls practices considered for the oil wells drilled within the past three years and potential wells that are planned to be drilled in the coming five years.

2. Technology Description[2, 3]

Artificial Lift: Any system that adds energy to the fluid column in a wellbore with the objective of initiating and improving production from the well is considered an artificial lift system. Artificial lift systems use a range of operating principles, including rod-beam pumps, ESPs, PCPs, and gas lift.

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1 ED Questions and Responses (072312PLe-gl) gepf

2 http://www.coscoesp.com/esp/basic%20artificial%20lift%20tech%20paper/Basic%20Artificial%20Lift.pdf

3 http://www.slb.com/~/media/Files/resources/oilfield_review/ors99/spr99/lift.pdf

2.1. Rod Beam Pumping

Rod pumps combine a barrel and piston with valves to transfer well fluids into the tubing and displace them to the surface. These pumps are connected to the surface by a metal rod string inside the tubing and are operated by reciprocating surface beam units, or pumping jacks that are powered by a prime mover – an electric or gas motor. Rod beam pumps are simple, familiar to most operators, and widely used. They are typically used in wells 10,000 feet deep or less, though they can be used in deeper wells if production rates are low to moderate.

Typical control methods for rod beam pumps are timers and POCs which cycle the well pump ON/OFF for a fixed time period to allow the reservoir to recharge with fluid levels sufficient to resume the pumping operation.

2.2 Electric Submersible Pumps

ESPs use multiple centrifugal pump stages mounted in series within a housing, mated closely to a submersible electric motor on the end of the tubing and connected to surface controls. They are powered by an armor-protected electric cable. Each stage adds pressure (or "head") to the fluid based on the pumping rate. The fluid builds up enough pressure as it reaches the top of the pump to lift it to the surface. ESPs are normally used in high volume applications (over 1,000 barrels per day). ESPs can be used in wells of any depth.

2.3 Progressing Cavity Pumps

PCPs are based on rotary fluid displacement. This spiral system consists of a rotor turning eccentrically inside a stationary stator. The rotor is a small diameter screw with deep round threads and extremely long pitch-distance between thread peaks. The stator has one more thread and longer pitch than the rotor, which forms cavities that progress in a rotating motion to create almost pulsation–free linear flow. Like rod beam pumps, the rotor is generally turned by rods connected to a surface motor. PCPs are flexible, resistant to abrasive solids, and volumetrically efficient. Compared to rod beam pumps, PCPs typically last longer and have fewer rod or tubing failures because of their slower operating speeds. PCPs are used predominantly in wells where the pumped fluid has a high solids content, and they can be used in wells to a maximum depth of 7,000 feet.

3. Research Method

The primary data collection activity for this study was telephone interviews with oil producers, equipment manufacturers, and industry experts, and analysis and reporting on the survey responses. A list of potential interviewees was provided by the IOU and consisted of 44 unique customer contacts in 36 oil fields and 12 contacts representing artificial lift well pump control equipment manufacturers. Interviews were completed with contacts from 17 oil producers (all 6 major oil producers and 11 minor oil producers)[4], 5 equipment manufacturers, and 2 consultants for a total of 24 interviews.

The interview questions were designed to collect data on the pump control mechanism typically used for operation of rod-beam pumps, ESPs, and PCPs[5]. For each of these pump types, oil producers were asked to estimate the distribution of control technologies on oil wells they had drilled within the past three years, as well as any expected changes or trends in control methods over the next five years. Manufacturers and consultants were asked to provide similar estimates based on the population of oil wells in California with which they worked. Pump control technologies investigated in the interviews included VSDs, POCs, throttling valves, continuous operation without controls, and any other alternative controls practices implemented or considered.

All potential respondents identified by the IOU were contacted by phone twice. If these attempts were not successful, a brief email was sent to the contact describing the purpose of the interview. If there was no response after a total of five phone calls and two accompanying emails, no additional efforts were made to reach that contact to solicit a response.

One to three interviewers participated in each interview. The survey instrument was administered, and the interviewers asked clarifying follow up questions as needed. Interview responses were typed in real time by one of the interviewers[6]. Qualitative and quantitative responses were analyzed, where appropriate, for minor and major oil producers, and across all participants. Table 1 shows the number of surveys completed for each market actor category.

Table 1: Survey Participants

Market Actor	# of Unique Participants
Major Oil Producers	6
Minor Oil Producers	11
Control Technology Manufacturers	5
Industry Consultants	2
Total	**24**

For quantitative data analysis, weighted average values were calculated using the approximate number of new wells of each pump type as reported by respondents. Information from the

[4] Major oil producers are organizations that accounted for 90% of oil produced in CA, according to an industry expert. All other oil producers were considered minor oil producers.

[5] See interview instrument, included in Appendix A of this report

[6] Redacted surveys are included in Appendix B of this report

manufacturer interviews and industry consultants was used primarily to corroborate survey findings and add perspective to the oil producer interviews.

4. Findings and Conclusions

Rod beam pumps are the most commonly used pumps for existing and new wells in California oil fields. Of the 17 oil producing companies interviewed for this study, 16 use rod beam pumps on at least some of their wells. As shown in Table 2 below, which shows the pump types for new and existing wells, rod beam pumps are on 92 percent of wells in the case of both Minors and Majors. ESPs are used on approximately 4 percent of wells in the case of both Majors and Minors, and PCPs are used on approximately 2 percent of wells for both Majors and Minors. A small percentage of wells flow naturally and require no artificial lift well pumps.

Table 2: Summary of Pump Type Distribution

Pump Type Distribution	Majors (6)	Minors (11)
Rod Beam Pumps	91.6%	92.3%
ESPs	4.1%	3.8%
PCPs	1.6%	2.2%
No artificial lift needed	2.7%	1.7%
N, #of wells reported by interviewees	5,225[7]	3,071[8]

4.1.1 Major Oil Producers: Rod Beam Pumping

Among the major oil producing companies, the large majority of rod beam pumps are controlled with POCs. As shown in **Error! Reference source not found.**, 84 percent of newly drilled oil wells with Rod Beam Pumps are controlled with POCs. The next most common is continuous operation without control, found on approximately 14 percent of newly drilled oil wells. VSDs are used infrequently, on approximately 3 percent of rod beam pumps. None of the newly drilled wells are controlled with simple timers, and no other control methods for rod beam pumps were reported by the interviewees. Figure 1 and Table 3 below show the distribution of control methods for rod beam pumps at major oil producing firms.

[7] Some of the majors provided specific estimates of new wells, while some only provided estimates of the combination of new and old wells. The reported total consists of 3,400 new wells, as reported by 4 major oil producers and 1,825 wells (new and existing), as reported the remaining 2 major oil producing firms.

[8] Some of the minors provided specific estimates of new wells, while some only provided estimates of the combination of new and old wells The reported total consists of 671 new wells, as reported by 6 minor oil producers and 2,400 wells (new and existing), as reported the remaining 5 minor oil producing firms.

Figure 1: Control Methods for Rod Beam Pumping at Major Oil Producers

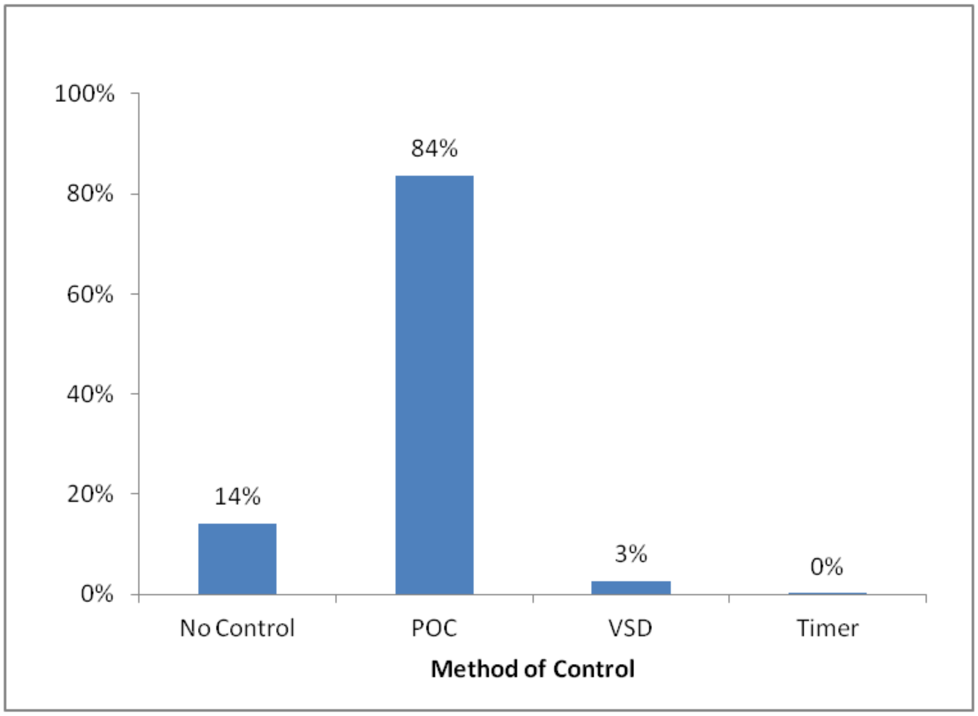

Table 3: Distribution of Control Methods for Rod Beam Pumping at Major Oil Producers

Itron ID	# of new RBP wells	Continuous w/o control	POC	VSD	Simple Timers
O12	2,025	5%	90%	5%	0%
O13	588	92%[9]	6%	1%	1%
O14	765	0%	100%	0%	0%
O15	160	10%	90%	0%	0%
O16	1,200	0%	100%	2%[10]	0%
O17	50	30%	70%	0%	0%
	4,788	**14%**	**84%**	**3%**	**0%**

4.1.1a. POC Control of Rod Beam Pumps at Major Oil Producers

Respondents emphasized a variety of specific points when discussing the added value of POCs on rod beam pump wells. Several respondents highlighted the advantages of telemetry, or the ability to obtain detailed information about downhole conditions from a remote data acquisition center, even in some cases on one's cell phone or other mobile device. Through their own research, majors

[9] This value is driven by one respondent who indicated that about 92 percent of their rod beam pumps are uncontrolled. For the remaining five major oil producers, the average percentage of wells operating without any controls is only 3 percent.

[10] VSDs are also equipped with POCs; therefore, the total exceeds 100%.

producers have been able to demonstrate that the presence of POCs leads to decreased average down time for the wells of approximately 15 percent in many cases. Respondents noted that POCs provide efficiency increases both in terms of reduced power consumption as well as improved well production. Part of this optimization stems from the ability to customize each stage in the stroke of each well pump to maximize overall production. Also, if the off time on a POC is kept to 5 minutes or less, then the POC can confer some of the same advantages of a VSD by preventing sanding of the well.

A majority of the respondents emphasized cost savings specifically associated with reduced maintenance and reduced wear and tear on the pump and well to the use of POCs. Reductions in the number of maintenance labor hours also decrease the safety risk associated with well operation. One respondent noted that these effects are particularly noticeable for deeper wells and that the effect on maintenance cost for shallow wells is less pronounced.

One of the respondents, who indicated that a majority of their wells are uncontrolled, also noted that they are in a testing phase with POCs to determine the particular range of conditions under which they are economical to use. This firm does not have any POCs installed currently due to the shallow nature of their wells. In cases where the fluid volume of the well is very high, for example where there is a high water cut, there may never be a risk of achieving a pumped off condition. These wells may be in continuous operation whether or not a POC is installed, so the added cost of the POC is not justified unless downhole conditions change. Some considerations regarding these downhole conditions correspond with geographic location and reservoir characteristics. This respondent emphasized that new wells in the L.A. Basin are getting POCs, while this practice is less uniform in the San Joaquin Valley.

Several respondents noted that there has been a historical tendency for some producers to avoid POCs, stemming from the belief that they lead to a loss of jobs and that their value can be replicated through proper manual control. However, this culture has shifted toward a sense that POCs provide valuable information that is not otherwise obtainable. Some major producers are retrofitting existing wells with POCs, while others are not.

Conclusion: The benefits of using POCs to control rod beam pumps and associated cost savings are now proven. A large majority of newly drilled oil wells operated by rod beam pumps have used POCs as the control method (84%), and the major oil producers have been retrofitting their existing rod beam pumps with POCs. For these reasons, POCs should be considered standard practice on rod beam pumps for major oil producers. The cost of a POC, including parts and labor, is approximately $4,000. When compared to the $300k-$400k cost of drilling and installing a pump on a new well, this added cost is easily justified by the benefits of a POC. In general, respondents were in agreement that the proportion of rod beam pump wells with POCs will continue to increase over the next five years.

4.1.1b. VSD Control of Rod Beam Pumps at Major Oil Producers

In contrast to POCs, major producers indicated that the use of VSDs on rod beam pumps is uneconomical in most conditions and that the potential value of a VSD must be evaluated on a case by case basis. A number of respondents mentioned that they are in the process of testing the specific conditions under which VSDs add value to their operations. Several of these respondents noted that the technology of VSDs is improving in ways that may improve the range of conditions under which they are economical, so there's an iterative process of researching their value while the technology itself is in flux. As an example, one major producer noted that the VSDs they have tried in the past have failed due to windy and sandy aboveground conditions in the field that foul the drives and that they are working with the manufacturer to develop a better unit that will have a better response to the climate.

Advantages associated with VSDs are the additional data they can provide about downhole conditions beyond what a POC can provide. VSDs provide information about the well pump kW draw, weight on the beam, temperature data, and downhole pressure conditions that can be used to optimize the pump stroke as well as to diagnose downhole problems.

The upfront cost of VSDs is high, at approximately $13,000 per unit, based on interviews with producers and manufacturers. In addition, several respondents noted that there are expenses associated with VSDs that are not as visible as the upfront costs. Multiple respondents noted potential issues of harmonics in the power supply that can cause pump outage or damage to VSDs, resulting in added operating costs and loss of production.

Some respondents offered rules of thumb for conditions under which the use of VSDs is justified. Several respondents indicated that VSDs make sense when downhole geological factors lead to high sanding risk, though some respondents noted that the added cost may not be justified even in these conditions. The ability of VSDs to keep the pump operating at an extremely low rate and avoid the potential well sanding and head pressure associated with shutdown can confer savings associated with reduced maintenance. One respondent suggested that VSDs are justified for well pumps of 100 HP or over, while another said his company installs VSDs on anything with a gearbox rating of 640 or higher. Another respondent indicated that VSDs add the most value for wells where there is a lot of fluid entry into the well. The range of conditions under which VSDs make sense economically is expected to grow as VSD prices decline.

Three of the six respondents noted that VSD packages usually also include POCs for added telemetry, though some respondents did not take advantage of the POC software option that comes with their VSD package.

Conclusion: The use of VSDs to control rod beam pumps is not yet proven. The major oil producers are still experimenting with VSDs to find the right applications for its use on rod beam pumps as evident from low installation rate (3%) in new wells. Therefore, VSDs are not yet standard practice for controlling rod beam pumps for major oil producers.

4.1.1c. Continuous Operation/ Other Control Methods of Rod Beam Pumps at Major Oil Producers

The most common operating condition for rod beam pumps that don't have POCs installed is continuous operation without control. This is the case for approximately 14 percent of newly drilled oil wells among major producers. This value is driven by one respondent who indicated that about 92 percent of their rod beam pumps are uncontrolled. For the remaining five major oil producers, the average percentage of wells operating without any controls is only 3 percent.

Continuous operation without control is used for wells with low production levels (e.g. stripper wells where production is <1 barrel per day, per one Major producer) where it is not cost effective to add control. In these cases, a manual well production test is usually deemed adequate to set the pump rate and keep it running with periodic manual checks and adjustments as necessary. In a very small number of cases, major oil producers said they have simple timers on rod beam pumps. However, these were acknowledged to be an obsolete form of well pump control. As noted earlier, POCs and VSDs are also sometimes uneconomical in cases where fluid content is particularly high and there is little to no risk of pumping off the well. Thus, continuous operation with no control is seen both in cases of very low production and in cases of very high fluid content.

Conclusion: Continuous operation of rod beam pumps without any form of control is not a typical practice for major oil producers.

4.1.2. Major Oil Producers: Electric Submersible Pumps (ESPs)

Respondents indicated clearly that the typical control technology on ESPs is a VSD. Almost all of the survey respondents indicated that they already utilize VSDs for ESP control and will continue doing so for newer wells. All three of the six major oil producers that have installed ESPs in newly drilled oil wells indicated that they have installed VSDs on 100 percent of the wells (Figure 2 and Table 4

Figure 2: Control Methods for ESP Operation at Major Oil Producers

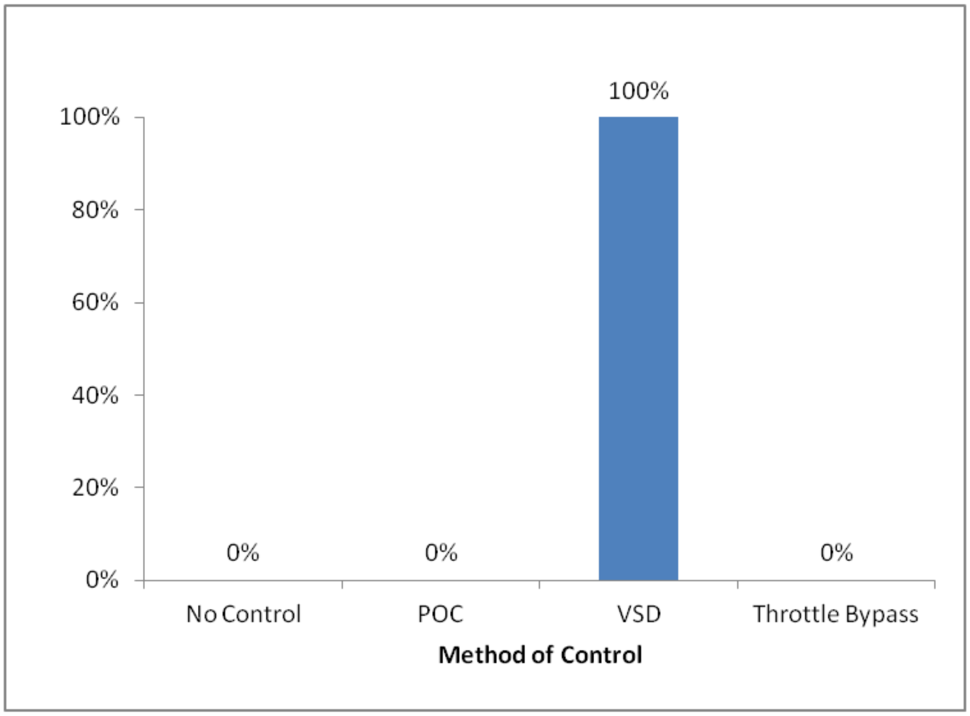

Table 4: Distribution of Control Methods for ESP Operation at Major Oil Producers

Itron ID	# of ESP wells	Continuous w/o control	POC	VSD
O12	56	0%	0%	100%
O13	38	0%	0%	100%
O14	120	0%	0%	100%
	214	**0%**	**0%**	**100%**

Respondents stressed that VSDs tend to be part of the standard package when purchasing an ESP from the manufacturer and may be included as a requirement in the contract. One respondent specifically noted that VSDs are standard with NEMA B high efficiency motors. Another respondent emphasized that in cases where production inflow is not constant, there is no other option but to operate the pump with a VSD.

VSDs were noted for their ability to improve monitoring and enable optimization of production, as well as to help find ways to keep up production. Even in cases where the conditions may not require varying the pump rate, the VSD allows monitoring and control based on downhole information on temperature, pressure, and also on the power drawn by the well. Controlling the power draw, specifically, helps keep gas from interfering. One respondent noted that in the past ESPs were sometimes run continuously without control and that they were sized for the appropriate level of production. But with the increased flexibility of control available through a VSD, this trend faded. Another respondent acknowledged that the flow rate of ESPs can be controlled using a throttle or choke, and that they sometimes use this approach, but that it is done in conjunction with VSD control rather than in place of it. Some respondents noted that the issues they encountered with harmonics in the power supply led to putting everything on a switchboard to mediate this issue, but they continued to operate their ESPs with VSDs.

A majority of the respondents indicated that the use of VSDs as standard practice on ESPs can be expected to continue. One respondent did note, however, that there will be an ongoing effort to reduce the cost of controllers. This may take the form of more dual frequency pumps, or multiple pumps of different sizes downhole that are turned on and off remotely to control the pumping rate.

Conclusion: Without exception, the three major oil producers that have ESPs installed indicated that they are all operated with VSD control. Based on the results described above, VSDs should be considered standard practice for controlling ESPs for major oil producers.

4.1.3. Major Oil Producers: Progressing Cavity Pumps

Three of the six major oil producers interviewed indicated that they have installed PCPs in new wells. The other three Majors do not have any wells with PCPs. As with ESPs, all respondents indicated that they have installed VSDs in all cases for these wells (Figure 3 and Table 5). The most common mode of control for PCPs, as found during this assessment was the use of VSDs. Two of the operators interviewed confirmed that PCPs at their respective facilities were designed with VSD controls, since it is, in effect, the only way of communicating with the well.

The very low rotations per minute (RPM) that are achievable with a VSD increases the opportunity to get the cavity between the stator and rotor filled when moving fluid up the shaft of the well. In addition, respondents accentuated that VSDs on PCPs are an essential safety measure. The presence of a VSD serves as a check on the substantial torque that can build up in a PCP rotor. If this torque is allowed to build, the rotor can snap and potentially cause injury to well operators, as well as incur substantial repair cost. According to the interviewees, given the costs and labor considerations associated with operation of these wells, more and more operators across the industry are leaning toward VSDs for PCPs as a standard practice.

Figure 3: Control Methods for PCP Operation at Major Oil Producers

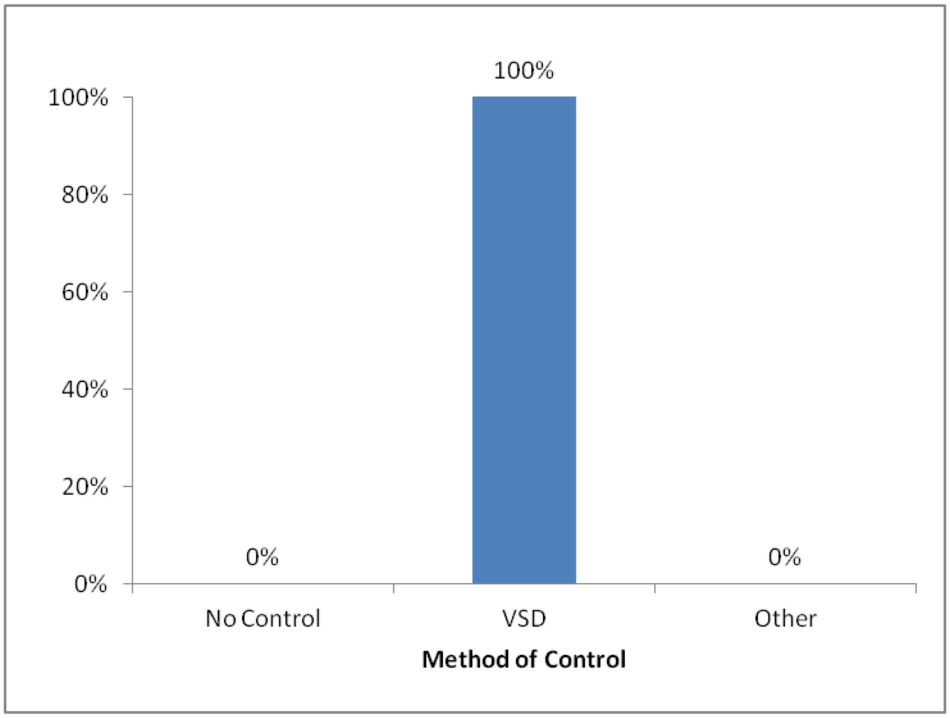

Table 5: Distribution of Control Methods for PCP Operation at Major Oil Producers

Itron ID	# of PCP wells	Continuous w/o control	VSD	Other
O12	68	0%	100%	0%
O14	15	0%	100%	0%
O15	2	0%	100%	0%
	85	**0%**	**100%**	**0%**

Conclusion: As with ESPs, the use of VSDs should be considered standard practice among major oil producers for control of PCPs. One central driver of this standard practice is the fact that the design of most PCPs is dependent on the pumped fluid to provide lubrication between the rotor and the stator. If a PCP achieves a pumped off condition and continues to operate, the elastomer lining of the stator will burn off quickly and most likely result in substantial repair costs and production downtime. While metal-on-metal PCPs are currently under development, they are not yet widely deployed for commercial production.

4.2 Minor Oil Producers

4.2.1. Minor Oil Producers: Rod Beam Pumping

Minor oil producers largely operate rod beam pumps continuously without control on new oil wells. As shown in Table 6 below, continuous operation without control accounts for approximately 83 percent of these rod beam pumps, and this figure is driven specifically by the producers on the upper end of production levels within the minor producer category. POCs were used on approximately 11 percent of new wells; VSDs are used on 4 percent of new oil wells, and a small fraction of rod beam pumps are on simple timers.

Figure 4: Control Methods for Rod Beam Pumping at Minor Oil Producers

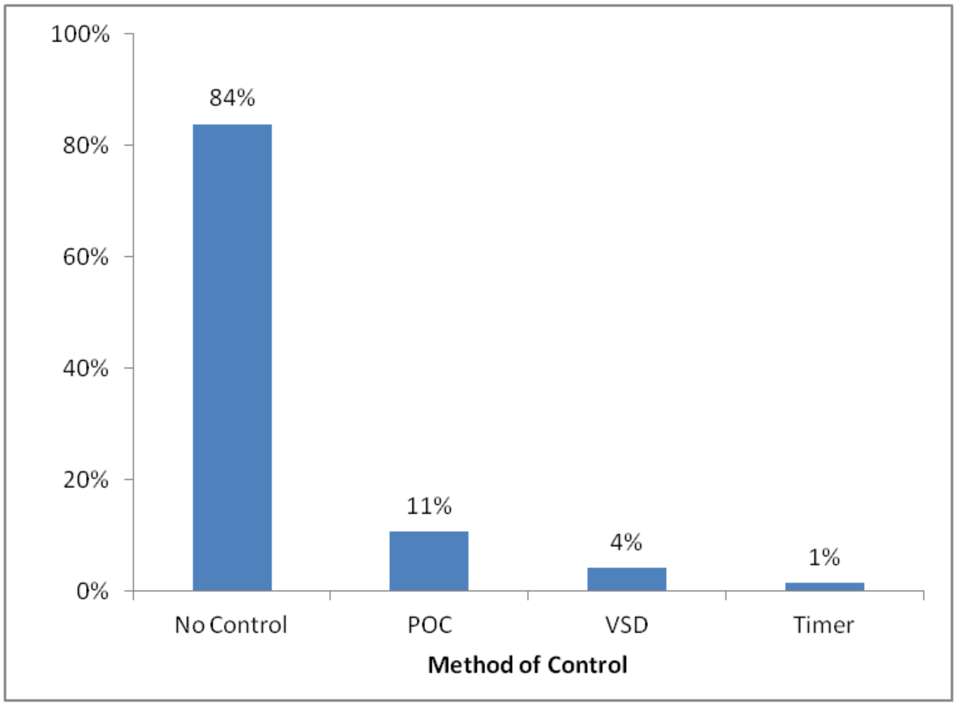

Table 6: Distribution of Control Methods for Rod Beam Pumping at Minor Oil Producers

Itron ID	# of new RBP wells	Continuous w/o control	POC	VSD	Simple Timers
O1	90	0%	98%	2%	0%
O2	550	100%	0%	0%	0%
O3	435	100%	0%	0%	0%
O4	150	0%	75%	0%	25%
O5	990	85%	10%	5%	0%
O7	2	0%	0%	0%	100%
O8	26	0%	0%	100%	0%
O9	1	0%	0%	100%	0%
O10	38	0%	0%	100%	0%

O11	550	100%	0%	0%	0%
	2,832	**84%**	**11%**	**4%**	**1%**

Minor producers provide a variety of reasons for why they select each of the typical control methods. In the case of stripper wells (<1 barrel of oil per day) the cost of a POC or other control method is often not able to pay for itself through increased production within one year, which is a typical threshold payback period. Some respondents noted that well pump control can be achieved through alternative means, such as changing sheaves. Several respondents indicated that their wells continually experience high fluid levels, so the wells are never pumped off, and there is no need to control the pumping rate. One respondent said that the oil field where he works is in a low pressure reservoir and that keeping the wells running continuously and pumped off as often as possible maximizes production in these conditions. As with the major producers, a majority of the minor oil producers noted conditions under which POCs are often used. POCs are more likely to be seen in use when production is more than 100 barrels of oil per day. However, POCs do not work well for pumping heavy-grade oil.

Similarly, minor oil producers noted that there are no hard, fast rules for when VSDs are warranted on rod beam pumps, but there are a few circumstances where they are more likely to be found. Some respondents noted that the savings from avoided sanding and pullout jobs, as well as the reduced maintenance resulting from a VSD's ability to keep a pump optimally loaded at a high power factor, can sometimes justify the relatively high cost of this control method. VSDs provide value in the case of injector (steam) wells, since the steam leads to high water cut as well as frequent cycling of the well and associated challenges with optimizing production. A number of small producers are testing the effects of different levels of back pressure on water cut as part of optimizing the pump stroke with VSDs. Some respondents emphasized that the detailed downhole information provided by VSDs has value to them at a big picture level, potentially beyond the near term optimization of one particular well's pump stroke, especially when integrated with all the other data in their supervisory control and data acquisition (SCADA) system.

Conclusion: In the case of minor oil producers, neither a POC nor a VSD can be considered as industry standard practice for controlling rod beam pumps.

4.2.2. Minor Oil Producers: Electric Submersible Pumps (ESPs)

Three of the eleven Minor producers that were interviewed indicated they have installed one or more ESPs (117 total) in the past three years. VSDs are in use on the large majority of these wells. Two of three respondents who have installed ESPs indicated that VSDs are on all of their ESP wells, and the third respondent indicated VSDs are on $2/3^{rd}$ of their ESP wells. Overall, VSDs are on approximately 97 percent (113 wells total) of ESPs among these small producers. The remaining 3 percent (4 wells total) are operated continuously without control as illustrated below in Figure 5 and Table 7.

Figure 5: Control Methods for ESP Operation at Minor Oil Producers

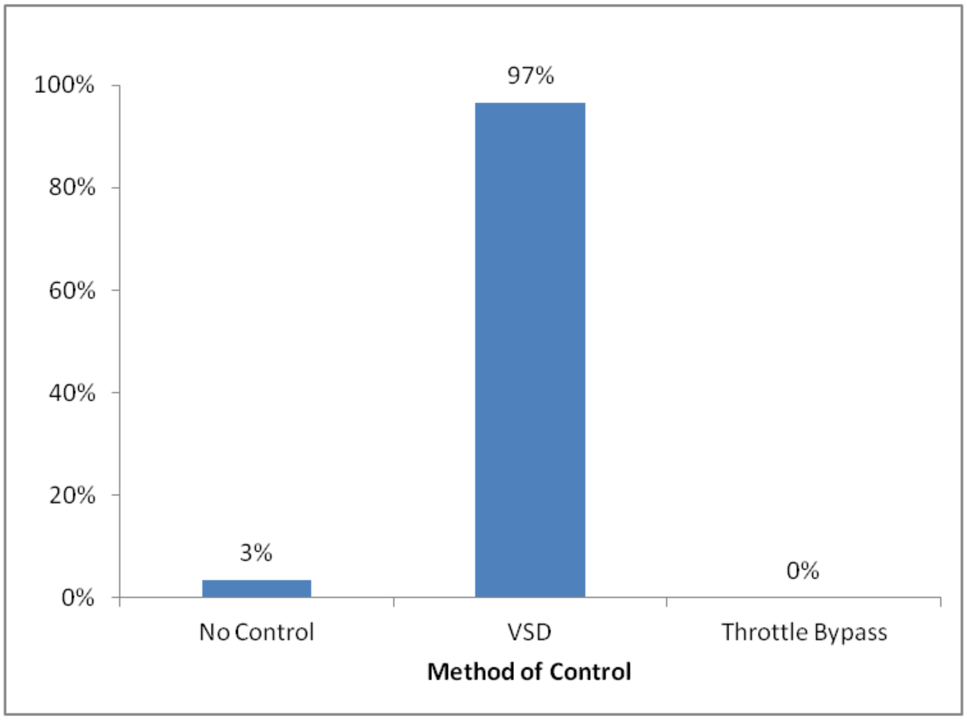

Table 7: Distribution of Control Methods for ESP Operation at Minor Oil Producers

Itron ID	# of new ESP wells	Continuous w/o control	VSD
O1	6	67%	33%
O3	110	0%	100%
O7	1	0%	100%
	117	**3%**	**97%**

Conclusion: Respondents noted that ESPs are typically used in the early life of a well and that the well operator may not know the well's production capacity at that early stage. The flow rate may also be more variable in general at that early stage. VSDs provide the ability to control the pumping rate and monitor reservoir pressure, fluid levels, and reservoir temperature, hence their use in almost all cases on ESPs for small producers. The only case cited in which VSDs are not used on ESPs is when the well is producing too much fluid (in the nascent stages of well operation) to need or justify a VSD. Nearly all new oil wells with ESPs are being controlled with VSDs. For these reasons, VSDs should be considered standard practice on ESPs for minor oil producers.

4.2.3. Minor Oil Producers: Progressing Cavity Pumps

Three minor oil producers indicated they have installed PCPs in new wells. The overwhelming majority of newly drilled PCP wells have VSDs installed (Figure 6 and Table 8). In one case, a respondent indicated that 10 percent of their PCP wells run continuously without control due to very high flow volumes and therefore carry little to no risk of achieving a pumped off condition.

Figure 6: Control Methods for PCP Operation at Minor Oil Producers

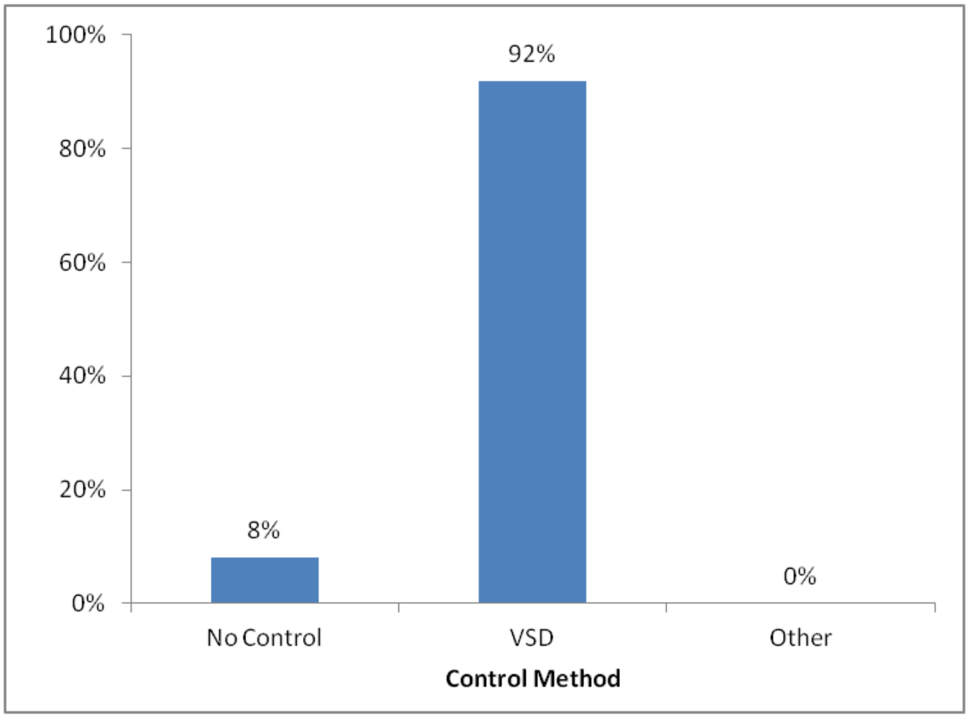

Table 8: Distribution of Control Methods for PCP Operation at Minor Oil Producers

Itron ID	# of PCP wells	Continuous w/o control	VSD	Other
O1	54	10%	90%	0%
O3	2	0%	100%	0%
O6	11	0%	100%	0%
	67	**8%**	**92%**	**0%**

Conclusion: As with ESPs, only 3 out of 11 small producers interviewed said they have PCPs on one or more wells. VSDs are used on these pumps in almost all cases. Each of these respondents noted that VSDs allow the operator to keep the fluid levels up in the pump so as not to pump it off and consequentially burn or damage the well. Two respondents also mentioned the value of VSDs in preventing overloading and modulating torque, which translates to reduced maintenance costs. One respondent specified that the PCPs used on the wells he oversees were designed with VSDs incorporated in them. A majority of the respondents also pointed out that VSDs enable remote operation of the pump and provide the ability to monitor reservoir pressure and temperature. Based on the results described above, VSDs should be considered standard practice on progressing cavity pumps for minor oil producers.

4.3. Pump Control Technology Manufacturers

Pumping control technology manufacturers corroborated the perspectives of the producers and added perspective on trends in artificial lift pump type distributions/market share and the prevalence of different control methods for each pump type at major oil producing firms as described below.

4.3.1. Majors: Pump Type Distribution and Trends

All manufacturers confirmed that rod beam pumps is the most commonly used artificial lift pump in California and it is expected to remain that way. One manufacturer said this is driven in part by the fact that producers trust rod beam pumps and understand how they work. ESPs and PCPs make up 10%-20% of the market for new wells, with ESPs comprising most of that share. One manufacturer emphasized that this distribution of pump types used in new oil wells is driven largely by geological factors that vary by region; for example, ESPs are more popular in Kern County than in the San Joaquin Valley. Another manufacturer emphasized that the choice of pump varies by company for the majors, with some investing more heavily in PCPs, which still represent a small fraction of all pumps. One manufacturer stated that the high torque that is inherent in the design of a PCPs means it will always remain in a niche market.

Three manufacturers said that it is common for oil producers to change the type of artificial lift pump used in a well at different stages of the well life, based on the reservoir maturity. That is a new oil well may initially use one type of artificial lift pump, which is later changed to another type of artificial lift pump. In such a change out, the entire pump assembly and controls are replaced. Specifically, some wells use ESPs for approximately the first six months of the well's life when production levels are at their highest and are then replaced with another pump type (typically a rod beam pump) as production declines. In other cases a producer may change from a rod beam pump to an ESP to help increase production, driven in part by the high price of oil that puts a premium on marginal increase in production rate. Two manufacturers noted that emerging technologies should not be overlooked when thinking about trends in technology distributions and control methods, as well as structures for incentive programs.

For example, regenerative pumps are emerging that harvest energy from one part of the stroke cycle and apply it to another part of the stroke cycle, thereby delivering significant energy savings. Also, jet pump technologies are being installed in some new oil wells, especially in Kern County, and these may compete with PCPs. These jet pumps use a nozzle at the bottom of a well to produce a jet flow pattern with a low pressure point that draws fluid up into the pipe. Because this type of pump has no moving mechanical parts, it has a very high tolerance for solids content in the moving fluid.

4.3.2 Minors: Pump Type Distribution and Trends

The manufacturers were not able to provide their insights into the pump type distribution for minor oil producers. One manufacturer estimated that approximately 60 percent of new wells drilled by the minors have rod beam pumps. Another said that shallow wells (<5,000 feet) can't economically make use of ESPs; therefore, the use of ESPs on the part of small producers is limited.

4.3.3. Pump Control Methods

4.3.3a. Major Oil Producers: Rod Beam Pumping

The manufacturers confirmed reports from the oil producers that POCs are standard practice on rod beam pumps and that VSDs cannot yet be considered standard practice but that they are on the rise. According to two manufacturers, the large oil producers have been very aggressive at putting POCs on rod beam pumps over the past five years and cited savings on maintenance and production optimization as primary reasons for doing so. Two manufacturers cited utility rebates as an important driver in the widespread adoption of POCs on rod beam pumps. One of these manufacturers noted that rebating on POCs in California has been aggressive. The other noted that at this point in time, while the rebate for POCs remains a motivator, it has become standard practice among the major producers to use them, especially given the high price of oil.

Three manufacturers emphasized that VSDs are being installed on rod beam pumps at an accelerating rate, and they expected this trend to continue over the next five years. One manufacturer estimated that VSDs will be on 50 percent of rod beam pumps for major oil producers in five years, while another suggested this number will be closer to 60%-75%. This latter manufacturer estimated that three years ago VSDs were on only 5%-10% of rod beam pumps for the majors and that the budgeting for and conversion to VSDs as the dominant trend is happening right now. A third manufacturer stated more generally that there is a major trend toward using VSDs. As one manufacturer put it, "VSDs are getting a lot closer to being universally accepted in theory; even if in practice a number of wells don't have them on there." One manufacturer noted that even while the current adoption rate of VSDs is high, within five years it is likely that regenerative drives that harvest and re-use their own waste heat will be taking the place of VSDs.

These manufacturers cited several factors that are driving the increased adoption of VSDs for rod beam pumps. Three manufacturers emphasized the current push toward optimization of production. This was noted as both a cultural phenomenon, as oil well operators now largely accept that the added up front cost of a VSD is often justified, as well as a strict savings calculation phenomenon, as the high price of oil drives individual operators to optimize well production. One manufacturer stressed that the ability to control many wells from one point using telemetry is a driving factor for increased VSD adoption, especially as more wells are drilled in remote locations. Another manufacturer noted that in some cases a VSD comes as an integrated part of a software package with a POC. A third manufacturer noted that VSDs are sometimes installed in clusters, i.e., a given producer invests in VSDs and installs them on multiple wells in a given area.

One manufacturer noted that using VSDs on horizontal wells increases production rates and yields savings on maintenance. The same manufacturer noted that utility rebates helps in the adoption of VSDs, but that it's getting to the point where large producers see the benefit of automation even in the absence of rebates. Figure 7 and Table 9 below provide the summary of findings from manufacturer interviews for the distribution of control methods of rod beam pumping at major oil producers.

The interviewed manufactureres could not provide any perspective on the well pump control methods at the minor oil producing firms.

Figure 7: Manufacturers' Estimate of Control Methods for Rod Beam Pumps at Major Oil Producers

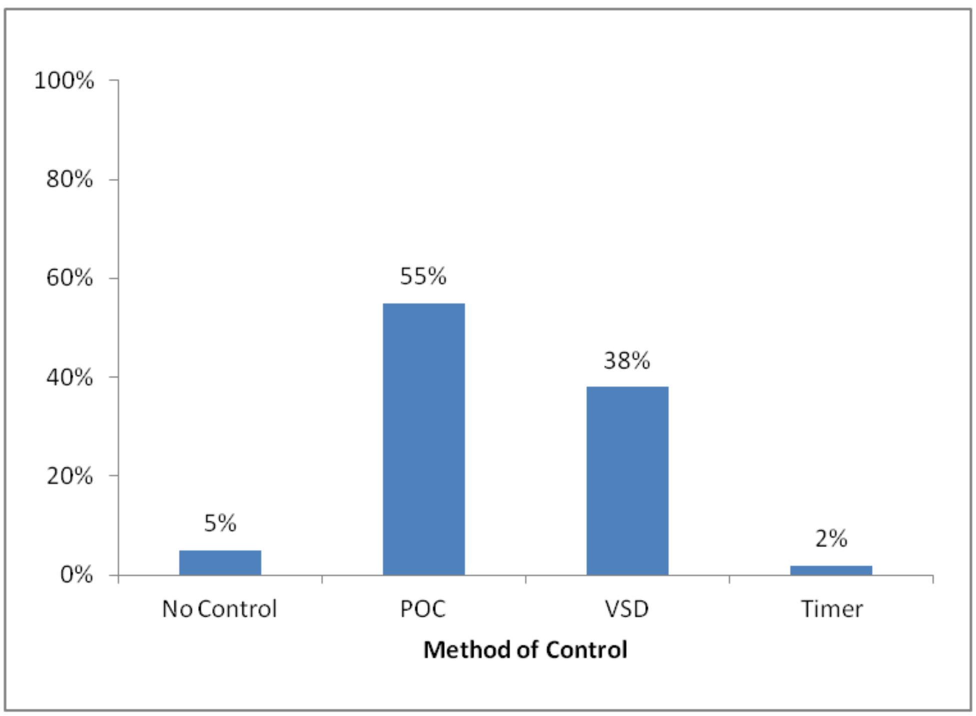

Table 9: Manufacturers' Estimated Distribution of Control Methods for Rod Beam Pumps at Major Oil Producers

Manufacturer	Continuous	POC	VSD	Timers

VM1a	0%	60%	40%	0%
VM1b	15%	30%	50%	5%
VM2a	0%	30%	70%	0%
VM2b	0%	80%	20%	0%
VM11	10%	75%	10%	5%
Average:	**5%**	**55%**	**38%**	**2%**

4.3.3b. Major Oil Producers: ESPs

One manufacturer provided perspective on control methods for ESPs and corroborated the findings from the producer interviews that VSDs are standard practice on ESPs. This manufacturer emphasized that VSDs can be used for power factor improvements and that the use of VSDs increases production and adds to the well operator's ability to control pumping. When asked about the prevalence of throttle bypass as a control method on ESPs, this manufacturer said that this is an inefficient method of control and that it is not recommended, nor is it commonly practiced. Figure 8 and Table 10 below provide the summary of findings from manufacturer interviews for the distribution of control methods of rod beam pumping at major oil producers.

Figure 8: Manufacturers' Estimate of Control Methods for ESP Operation at Major Oil Producers

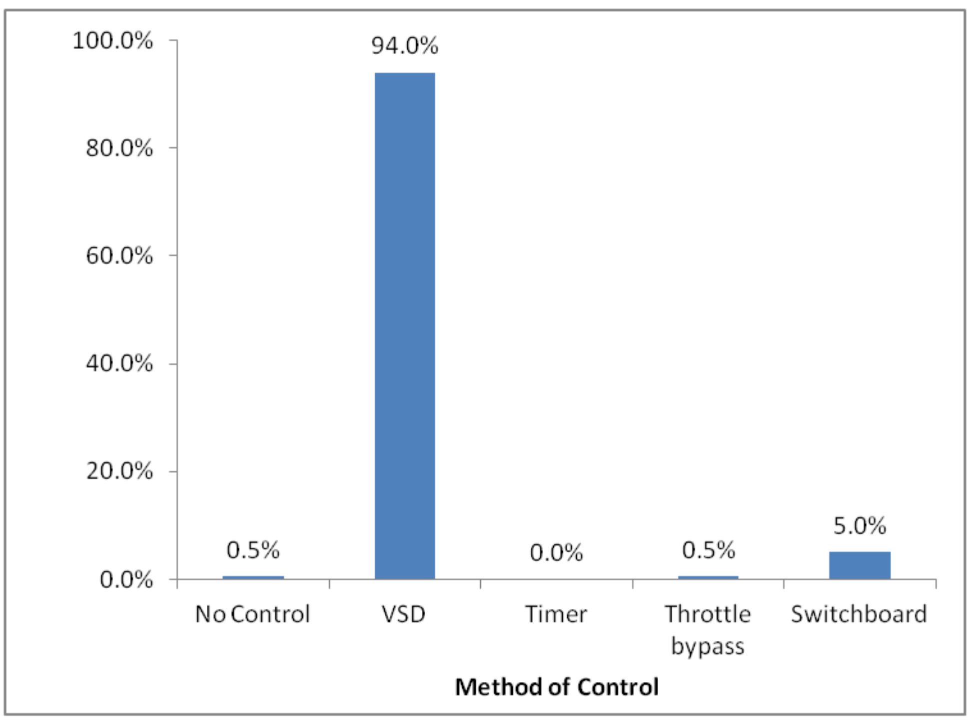

Table 10: Manufacturers' Estimated Distribution of Control Methods for ESP Operation at Major Oil Producers

Manufacturer	Continuous	VSD	Timers	Throttle Bypass	Switchboard
VM4	1%	99%	0%	0%	0%
VM11	0%	89%	0%	1%	10%
Average:	**0.5%**	**94%**	**0%**	**0.5%**	**5%**

4.3.3c. Major Oil Producers: PCPs

The three manufacturers that provided perspective on PCPs all reinforced the findings from the producer interviews that VSDs are industry standard practice on PCPs, most importantly because the functioning of PCPs is so dependent on maintaining fluid levels in the pump. One manufacturer said there are no other meaningful control options for PCPs, and another pointed out that the use of VSDs limits the torque, which in turn limits breakage. As with other pump types, VSDs enable telemetry with PCPs, which is useful for operating wells in remote locations and enabling control of many wells from one point.

One manufacturer noted that VSDs are standard practice for horizontal drilling, and horizontal holes are being drilled increasingly than straight vertical holes for new wells. This trend is driven in part by the fact that with horizontal wells, instead of going into just one reservoir that a vertical hole would access, the producer can access multiple reservoirs, which results in better fracking and increased production.

While it is clear that VSDs are standard practice for PCPs, one manufacturer noted that for wells in locations where water and oil flow very freely, such as in a fault line, it can be impossible to pump the well dry and that a VSD is unnecessary in these conditions. The manufacturers' estimate of control methods used for PCP-driven oil wells is shown in Figure 9 and Table 11.

Figure 9: Control Methods for PCP Operation at Major Oil Producers

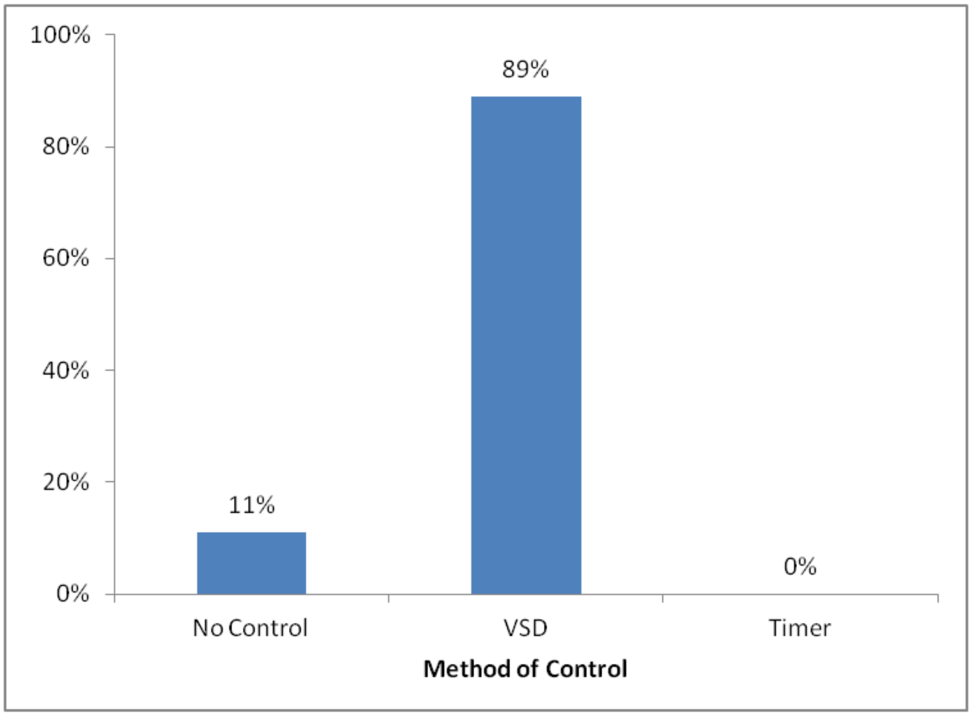

Table 11: Distribution of Control Methods for PCP Operation at Major Oil Producers

Manufacturer	Continuous	VSD	Timers
VM1a	0%	100%	0%
VM2b	0%	100%	0%
VM11	33%	67%	0%
Average:	**11%**	**89%**	**0%**

4.4 Industry Consultants

The two consultants interviewed also corroborated the results from the oil producer interviews regarding distribution of well types. Both consultants estimated that approximately 80%-90% of new wells have rod beam pumps, with ESPs making up the majority of the remaining pumps. ESPs are more commonly found in coastal and offshore drilling and are necessary in some cases for deeper wells, which is the current trend in California. Long stroke pumps are also beginning to enter the market and have just 2%-3% of current market share, and are mostly installed in the coastal mountain areas of Santa Barbara and Oxnard. One consultant noted that part of the market for new PCPs is conversions from rod beam pumps, since both of these pump types viable at low production levels. As per this consultant, ESPs are only viable at relatively high production levels.

The consultants concurred with the producer and manufacturer findings for the standard practices of the well pump control types but were unable to provide any explicit insights on the control methods.

4.4.1. Major Oil Producers – Rod Beam Pumping

The interviewed consultants estimated that major oil producers install POCs on approximately 60 percent of new rod beam pumps and VSDs on approximately 5%-10% of new rod beam pumps. Both consultants confirmed the statements made by the producers and manufacturers that installing POCs has become a standard operating procedure wherever they are appropriate for the circumstances. The stripper wells in the Coalinga area were cited as one example where POCs are unnecessary, since the low production rate doesn’t justify the cost of the POC. In contrast, they said that higher production wells are getting POCs in almost every case.

One of the two consultants emphasized that VSDs are used most often in cases where it is not practical to use a POC, such as horizontal boring, injection, and sandy situations. In these situations, the decision to use a VSD is driven by the economics of increased production as compared with continuous operation without control. This calculation is made on a case by case basis. Other factors that would enter into the decision would include the tendency of the well to produce solids, viscosity, and temperature of the oil, the gas-oil ratio, and the remote telemetry capability enabled by the VSD. Remote telemetry would be a comparatively more important consideration for an oil producer with many wells operating over a large area.

One consultant noted that aversion to new technologies in general is a barrier to wider adoption of newer control methods. In the case of retrofitting existing wells to add a control technology, another barrier is the cost associated with interrupting production for 1-2 days to install either a VSD or POC. The cost of downtime is significant when the price of oil is high. This consultant also noted that POCs are perceived as more reliable in the industry than VSDs. Since the typical total cost to install a VSD is $25,000-$30,000, compared with $5,000-$8,000 for a POC according to this consultant, a given producer should be willing to accept a 5-7 year payback period on a VSD compared with a 2-year payback period on a POC.

4.4.2 Minor Oil Producers – Rod Beam Pumping

The consultants estimated that for minor producers, approximately 40 percent of rod beam pumps in new wells are operated continuously without control and 50 percent with POCs. They estimated that 10 percent or fewer rod beam pumps for minor producers are operated with VSDs.

4.4.3 Minor Oil Producers – ESPs

The consultants corroborated the view of the producers and manufacturers that VSDs are industry standard practice on ESPs. They noted that the ability to vary the speed is really a built-in and a necessary feature associated with the transformer used with an ESP. Contemporary VSDs are typically tied into the SCADA system to enable feedback on key threshold conditions where the pump may run dry, or the temperature may fall outside of acceptable limits. Because ESPs are significantly more expensive to install than rod beam pumps, the cost of a VSD as a percent of the overall cost for an ESP is significantly smaller than for a rod beam pump. In this sense, the economic risk associated with the added cost of a VSD is smaller for an ESP than for a rod beam pump.

4.4.4 Minor Oil Producers – PCPs

The consultants also reinforced the view of the producers and manufacturers that VSDs are industry standard practice on PCPs. They noted that PCPs are typically operated at less than full speed and that VSDs give more flexibility to change speed as conditions change.

5. ISP Findings Summary

Table 12 recommends standard practice baselines that should be used for estimating savings from measures proposed to improve the control method for new oil well pumps. These recommendations are based on typical and dominant practice identified by interviewed oil producers, manufacturers, and industry consultants. Their views and quantitative assessments were largely similar. A major difference in their quantitative assessment was the estimated share of installation of POCs installed on road beam pumps by the major oil producers. The interviewed manufacturers estimated the share of POCs for rod beam pump applications at 55 percent. The industry consultants' estimate was 60 percent whereas the overall reported percentage of POCs installed by the major oil producers was 84 percent. The manufacturers stated that the share of VSDs used to control rod beam pumps was 38 percent, which was higher than 3 percent reported by the major oil producers. The use of VSDs to control rod beam pumps is a more advanced and efficient option as compared to POCs. The acceptance of VSDs for this application is not yet commonplace and its adoption does not appear to be high enough to be considered as the baseline control mechanism for rod beam pumps. ED, therefore, recommends using POCs as the baseline for controlling rod beam pumps at major oil producers. The ED also recommends that these baseline be applied to well conversions (e.g. artificial gas lift to rod beam / ESP, ESP to rod beam, etc,), since the entire lift method is replaced with a new, entirely different lift (pumping) technology, and the new construction/ replace on burnout baseline event is triggered.

Table 12: Summary of ISP Findings

Pumping Technology	Baseline Method of Control	
	Major Oil Producers	Minor Oil Producers
Road Beam Pumping	POC	Continuous Operation
ESPs	VSD	VSD
PCPs	VSD	VSD

6. Additional Findings

During the course of these ISP interviews, horizontal drilling was discovered to be an emerging technique of oil extraction in California. Although the survey respondents were not explicitly asked about standard/best practices in horizontal drilling, a few respondents provided their perspective on this new technique of well drilling where instead of drilling into just one reservoir, the producer can access multiple reservoirs, which results in better fracking and increased production. One manufacturer noted that VSDs are standard practice for horizontal drilling, and more and more horizontal holes are being drilled for oil exploration than straight holes.

Two major oil producers indicated that they install VSDs on horizontal wells that have experienced sanding The main driver for the VSD installation is that it will get energy savings and prevent sanding up in certain zones. Two other major producers responded that they are trying to get POCs to work on all of their horizontal wells. A couple of the minor oil producers indicated that they would think that VSDs would be the default option as horizontal wells are expensive and it would be a no-brainer to add VSD controls.

One of the interviewed manufacturers suggested that using VSDs on the horizontal wells is becoming a standard practice as they increase production, but not necessarily due to the additional energy savings. This manufacturer also suggested that all companies with new drills are getting some control at a minimum on horizontally drilled wells.

One of the interviewed consultants indicated that in instances where using a POC is not practical such as horizontal boring, injection and sandy situations, VSDs are becoming common practice. He also suggested that since VSDs are relatively a newer technology, only major oil producers would have exposure to it. According to this consultant, minor operators who have deep horizontal wells with high production but in sandy conditions would also be aware of VSDs and would be considering it as a default control option. In general, below-ground wells (including ESPs and PCPs) were discovered to be the most prevalent method of artificial lift due to their ability to handle the horizontal drilling better[11].

[11] Corroborated by 'FIGURE 3 - Artificial Lift Options' found in *'Selecting the Right Technology is Vital in Horizontal Wells'* (http://www.aogr.com/index.php/web-features/exclusive-story/selecting-the-right-technology-is-vital-in-horizontal-wells)

Appendix A – Survey Instruments

Available separately.

Appendix B – Redacted Survey Responses

Available separately