2003 ESP Workshop

Summary of Presentations

Prepared by

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The purpose of this document is to summarize the presentations, panel discussion, and break out sessions that were presented at the 2003 SPE ESP Workshop in Houston, Texas on April 29 – May 2, 2003. It is offered for those who couldn't attend the workshop.

If you would like to obtain a copy of the workshop proceedings, visit the workshop web site at www.espworkshop.com, contact the workshop organizers, or contact someone from your organization who attended the workshop.

Paper	Author(s)	Summary of Discussion
Keynote Address		
Growth of ESP's in Oman	Saif al Hinai, Oil Director of Northern Asset, **Petroleum Development Oman (PDO)**	This was a very interesting keynote address provided by Saif al Hinai, Director of the Northern Asset in Petroleum Development Oman. The northern asset comprises approximately 50% of PDO's total oil and gas production. Saif is an old friend of the ESP Workshop, having presented here before. Earlier in this career, he worked for a time for Shell Oil Company in Houston, Texas. <u>Oman in Perspective</u> • PDO produces about 800,000 barrels of oil per day. • This is about 90% of total Omani production. • Of this amount, 46%, or nearly 370,000 BOPD, is produced by ESP's. • Oman is about the size of the State of Kansas. • 75% of the national income comes from oil production. • Oman has a very rich culture. In former times, it was a major seafaring culture in the Middle East. <u>PDO in Perspective</u> • PDO was started in 1966, mostly focused on oil production. • Major gas development started in 2000. • PDO is "owned" 60% by the Omani government, 34% by Shell, and 6% by others. Shell is the operating company. • PDO has 66 production stations serving 117 fields. • It has over 3000 active wells. Most producing wells are on artificial lift. • PDO operates about 800 ESP's and the number is growing rapidly. • Total estimated oil in place (STOOIP) is 50 billions

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		barrels. • Of this 13% has been produced. The ultimate target is to recover 50%. • PDO faces declining primary production. • There is a strong focus on secondary recovery and many of the reservoirs are undergoing waterflood. • There is a large focus on improving organizational capabilities and skills. PDO Development Focus • The North of PDO has primarily carbonate reservoirs. • The South has primarily sandstone reservoirs. • The central part has a combination. • Nearly all new wells are horizontal completions. ESP Focus • Now there are approximately 800 ESP's. • By 2007, up to 1400 ESP's are anticipated. • Currently, 30% of the oil wells are produced by ESP, 38% by beam pumping, and 23% by gas-lift. • ESP run life has been continuously improving: o 1995: 563 days o 2000: 740 days o 2003: 836 days o 2006: 1153 days (target) • To improve ESP operations, PDO has a dedicated ESP team. o They are working to improve downhole information, especially on horizontal completions. • PDO relies heavily on alliance contracts for its ESP operations. o 80% are on lease contracts. o They are working with their alliance partners to find an optimum balance between production and run life. • PDO is working to improve the technical performance of its ESP systems. o They are beginning to use proactive maintenance to change out worn ESP equipment when a pulling unit is available, and before ultimate failure occurs. o They are working to determine the root causes of failures. o They are using on-site consultants to provide both classroom and hands-on training. o They are using enhanced equipment when warranted. Future in PDO • There will be a primary focus on secondary and tertiary recovery. • They are working to develop integrated production

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<tr><td></td><td></td><td>systems.
• There is a big push to enhance staff expertise.
• There is support for new R&D to enhance artificial lift performance.

<u>Questions and Answers</u>
• Question: Please tell us more about proactive maintenance.
  ○ Answer: It is being used where it is clearly economical.

• Question: What is PDO's strategy for dealing with gassy production?
  ○ Answer: PDO is involving vendors and experts in upfront design to address new challenges such as gas, sand, horizontal wells, etc.</td></tr>
<tr><td colspan="3">Session I – Flow Conditions</td></tr>
<tr><td>Performance Evaluation of a New Gas Handler in an Oil Well with as much as 60% Free Gas at the Intake</td><td>Ramez Guindi, Luis Afanador, Jose Flores, Hector Aguila, Schlumberger

Jose Villamizar, Alex Beltran, Hocol SA</td><td>This is a story about use of the Schlumberger Poseidon gas handler in Hocol, Colombia.

<u>Field Description</u>
• 15,500 BOPD.
• 50% of wells on ESP.
• Sandstone reservoir.
• WAG (water alternating with gas) process with a high frequency of switching between gas and water – between 15 and 60 days.
• Gas interference is apparent from the amps charts.

<u>History</u>
• Have tried gas separators, shrouds, bottom intakes, other gas handlers, and now the Poseidon.
• They experience that too much gas reduces the pump efficiency and can lead to gas locking.
• Gas accumulates in the low pressure areas of the impeller vanes.

<u>Gas Handler</u>
• The gas handler generates some head even at high gas volume factors.
• It helps to prevent gas lock.
• It acts as a "charge pump" to "prime" the main ESP pump stages.

<u>Poseidon</u>
• Uses axial flow, with low radial velocity.
• Can handle up to 75% free gas.</td></tr>
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<tr><td></td><td></td><td><u>Case History</u>
• One case history was presented where the production was increased and the amp chart was smooth.

<u>Questions and Answers</u>
• Question: What is the status of the Poseidon?
  o Answer: It is in the initial field trial stage.

• Question: What is the pressure drop across the Poseidon?
  o Answer: It is about 100 psi, depending on gas rate.

• Question: What is the performance in sandy production?
  o Answer: Performance should be about the same as with regular pump stages.

• Question: How does it deal with slug flow from horizontal legs?
  o Answer: It will be a problem when there is no liquid entering the pump.</td></tr>
<tr><td>Impact of Transient Flow Conditions on ESP's in Sinusoidal Well Profiles: A Case Study</td><td>Shauna Noonan,
Mike Kendrick,
Patrick Matthews,
ChevronTexaco

Ian Ayling,
Lyle Wilson,
CentriLift</td><td>This is a story about how to model and respond to slugs that can occur in sinusoidal profiles in "horizontal" completions.

<u>History</u>
• Slugs led to frequent shutdowns due to the intermittent gas and liquid slugs.
• Very difficult to model gas and liquid slugs with normal steady state models.

<u>Using Olga</u>
• Are using Olga to model transient flow.
• Can also see slugs on amp charts.
• Have determined "classes" of problems:
  o Slug dominated production
  o Free gas dominated production.

<u>Operational Strategies</u>
• Using VSD's to slow pump when gas slug hits
• VSD varies frequency to stabilize amp chart
• Using combinations of gas separators and gas handlers, which they refer to as "fluid conditioners."
• They have tried using a casing choke to increase annular pressure, but this can increase the slugging problem.
• Concerning well testing, they need to measure the actual production rates vs. time, not just the average daily production rate, to evaluate the slugging problems.</td></tr>
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<tr><td></td><td></td><td>They have been able to influence the drilling process to produce well bores that are more “friendly” for production.
<u>Questions and Answers</u>
Question: What have been the experiences:
Answers: With these various techniques they have reduced downtime by about 50%.
They are able to control the VSD based on the amps being drawn by the motor.
They are using an “auto orienting” pump intake, to place the intake on one side of the wellbore.</td></tr>
<tr><td>There’s No Free Lunch, Pumping Two-Phase Fluids with ESP</td><td>Lyle Wilson, CentriLift</td><td>This is a “mini” tutorial on the problems associated with trying to produce wells with free gas at pump intake conditions.

<u>The Problem</u>
With gassy production, we are trying to produce a two-phase fluid.
Gas is MUCH lighter than oil (0.001 times the water density).
Free gas greatly increases the volume of fluid that must be pumped.
The presence of gas can lead to some “flow anomalies.”
When pumping, the same velocity produces the same head, regardless of density.
Head is a function of velocity squared.
Head is a function of pressure divided by density.
Gas, being so much less dense, can’t displace liquid, so it gathers in the lower pressure areas in the impellers.
With the right design and conditions, liquid can “strip” some gas out of the impeller pockets. If it can’t strip enough gas, the gas “bubble” can increase and lead to a gas locked condition where the liquid cannot be stripped and pumped by the pump.
If the pump is stopped due to gas lock (low load), then some gas can percolate out. Then the pump can start pumping liquid again (for a while). This can lead to an amp chart that actually shows a sinusoidal shape.
There are certain features or characteristics that affect gas interference:
Density ratio between liquid and gas.
Bubble size.
Viscosity.
Pump geometry.
Some modern pumping systems are designed to try to affect some of these items – e.g. bubble size and geometry.</td></tr>
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<tr><td></td><td></td><td><u>Predicting if a Problem May Exist</u>
• Turpin developed a chart of Pressure vs. Vapor/Liquid Ratio.
• If the conditions of a well fall above the “Turpin” line, pumping conditions should be favorable. If they fall below the line, pumping may be difficult.
• Other researchers have made refinements to the Turpin chart.

<u>What to do if Have Gassy Production</u>
• If possible, avoid the problem by keeping the gas out of the pump.
• If this isn’t possible, expel the gas by gas separation.
• If this isn’t possible:
○ Homogenize the fluid – liquid and gas.
○ Increase the capacity of the pump.
○ Use the first stages to “condition” the fluid for the later stages.
○ Consider a tapered pump.
○ Consider placing holes in the impeller vanes to help the gas bubbles to vent.
○ Consider use of axial pump stages.</td></tr>
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<tr><td colspan="3">Session II – Unique Applications</td></tr>
<tr><td>Application of High Volume, High Temperature Turbine HSP Operation</td><td>R. C. Chachula,
S. C. Solanki,
EnCana Corp.

W. G. Harden,
Weir Pumps Ltd.</td><td>This is a story about pumping high volume, high temperature wells in the Canadian SAGD (steam assisted gravity drainage) project.

<u>Field Conditions</u>
• Very high viscosity oil.
• Economics a function of steam/oil ratio.
• Goal is to reduce reservoir pressure as low as possible to minimize amount of steam required.
• Difficult to obtain sufficiently low bhp with gas-lift.
• Difficult to handle high temperatures and viscosities with conventional pumping.

<u>Challenges</u>
• 350 – 400 degrees F.
• 5,000 – 10,000 B/Day production.
• 90 – 220 psi flowing bottom-hole pressure.
• Horizontal pumping.
• Sand production.
• Steam flashing in production wellbore.

<u>HSP (Hydraulic Submersible Pump)</u>
• Range: 2500 – 7500 RPM.
• Production rate: 0 – 75,000 B/Day.
• Power fluid: water or oil.</td></tr>
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Paper	Author(s)	Summary of Discussion

		• Power fluid drives turbine that drives pump.
		• Can be open or closed loop.
		• Can:
		    o Stand high temperatures.
		    o Produce high rates.
		    o Operate at any angle.
		    o Is only about 5 metes (15+ feet) long.
		    o Has a wide speed range.
		    o Is wear resistant.
		
		<u>SAGD Trial</u>
		• Keep power fluid and production separate.
		• Testing of the system:
		    o Ran both cold and hot tests.
		    o Tested in 9 5/8” casing.
		    o System failed on test due to sand plugging.
		    o May have gotten solids from surface injection line.
		
		<u>Conclusions</u>
		• HSP worked OK.
		• It was OK up to 200 degrees C (approx. 390 degrees F).
		• Important to carefully flush all surface piping and use strainer to prevent injection of solids in power fluid.

Selective ESP Completion to Produce from Three Different Payzones	Patricio Alban, Armando Rueda, JesusGuerrero, Guillermo and Olegaria Rivas, **Schlumberger**
	
	Daniele Magherini, **Lasmo**
		This is a story about using a selective completion to produce three separate pay zones in one wellbore.
		
		<u>The Completion</u>
		• The well has three separate pay zones.
		• The zones are separated by packers.
		• Options are to produce two zones at a time up tubing or one up tubing and one up the annulus.
		
		<u>Options</u>
		• Use “Y” tool.
		    o Requires three separate wireline runs to access bottom-hole pressure tool and the pump must be stopped.
		• Use separate tubing strings.
		    o Can produce gas up one string and liquid up the other.
		    o Can run wireline tools with the pump running.
		    o Can choose selective completion.
		    o Can run wireline perforating tool while producing to obtain an underbalance.
		    o Can inject chemical or steam down second tubing string, using a coiled tubing insert string.
		    o Can run production logging tools.

Paper	Author(s)	Summary of Discussion
		<u>Questions and Answers</u> • Question: Isn't there a concern with sand with multiple packers in the hole? o Answer: This is true, but in this case packers are required to separate the zones. • Comment that a "Y" tool can also be used for underbalance perforating.
Dual ESP Downhole Water Sink Completion in Venezuela	Kelsey Gonzolez, Ignacio Martinez, Floyd Ireland, **Baker Hughes Centrlift**	This is an interesting story about using dual ESP's in PDVSA to produce oil from higher in a zone and water from lower in the same zone to arrest water coning. <u>Concept</u> • The concept is to arrest water coning up into the oil producing horizon. • The formation is perforated both in the oil column and the lower water column. • Water is produced up one string; oil up a second string. <u>Well History</u> • Well has 7" casing. • Oil production decreased when the water cut reached 96%. <u>Completion</u> • The ESP for pumping the oil is installed below the ESP for pumping the water. • The oil ESP is designed to pump 1000 B/Day. • The water ESP is designed to pump 3000 B/Day. • The oil is produced up past the water pump with three capillary tubes that "manifold" into a 1.5" coiled tubing. • The water is produced up 2 3/8" tubing. <u>Operation</u> • First, the 3000 B/Day water pump was started. • Then the oil pump was started. • Was able to produce more oil with the oil pump than before, but still some water. • Also produced some oil with the water pump. <u>Economics</u> • Completion cost about $600,000. • Return on investment was 94% based on 12-month run life. <u>Conclusion</u> • Dual ESP operation in 7" casing is viable.

Paper	Author(s)	Summary of Discussion

		<u>Questions and Answers</u>
		• Question: What is the life of the completion?
		    ○ Answer: There is concern about the small capillary tubes used to carry the oil production past the water pump.
		
		• Question: Are there more candidates for this type of completion.
		    ○ Answer: There are more candidates in PDVSA.

Wellbore Heating to Prevent Liquid Loading	Mike Parker, **Anadarko Petroleum**	This paper was originally presented as SPE #77649. It was a substitute paper in the workshop. Copies can be obtained from the Workshop Steering Committee. Mike said he got the idea for this project from information presented at a past ESP Workshop. Knowledge transfer works. <u>Background</u> • Some gas wells produce liquids. They may be “free liquids” or liquids from condensation. • Liquids from condensation may form in the tubing when the temperature drops below the dew point. • Typical artificial lift methods can remove “free” liquids, but not condensate. <u>Approach</u> • A way to prevent condensation is to heat the tubing or the flowing gas. • Can use the heat from an ESP cable to heat the gas, or can use larger tubing to produce more gas. • If can reduce abandonment pressure, can increase recoverable gas reserves. • In test well, used a downhole video camera to see flow in tubing. Could see areas of dry gas production and areas where condensate was forming. <u>Results</u> • Increased gas production from about 100 MCFD to over 500 MCFD. • Pluses: Increased production, reserves, and decreased maintenance. • Minuses: The process increased operating costs (for the electricity to heat the cable) and will not work with “free” water. <u>Future Ideas</u> • Use coated tubing for better thermal insulation. • Draw a vacuum on the annulus for better thermal insulation. • Deploy the heating cable with coiled tubing.

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<tr><td>Successful Down Hole Oil Water Separator (DHOWS) Installation</td><td>William D. Holmes, Monty D. Corbett, Marathon Oil Company

Daniel B. Wells, Baker Hughes Centrilift</td><td>This is a story about a downhole water separation and injection system, so that water does not need to be produced to the surface.

<u>DHOWS Concept</u>
• Separate oil and water downhole.
• Inject water downhole, below a packer.
• Use a bypass tube to bring oil up from lower “injection” pump to upper “booster” pump.

<u>Case History</u>
• Produce 78 BOPD and 337 BWPD at the surface.
• Inject about 6000 BWPD downhole.
• Saving about $50 per day in OPEX.

<u>Conclusions</u>
• A good DHOWS system can reduce water production.
• It can reduce OPEX.
• It can provide good run time.
• Must have a good downhole injection zone.
• Must have reasonably large casing diameter.

<u>Questions and Answers</u>
• Question. Why are there only a few in the world?
    o Answer: Need right conditions including a good downhole injection zone.

• Question: About how many are there.
    o Answer: There are about 80 DHOWS systems in the world. Workover costs are high.</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Session III – Case Histories Part One</td></tr>
<tr><td>Hot Line Temp Motor Pilot Implementation Project in Yani Deep and Low Productivity Wells in CNOOC Southeast Sumatra Contract Area</td><td>Sunarto Halim, Robianto Soekama, CNOOC

Andrew Macae, Dwi Yulianto, Schlumberger</td><td>This is a story about implementation of an ESP in a very challenging hot, deep, tight reservoir in Sumatra, Indonesia.

<u>Field Conditions</u>
• Offshore Java, Indonesia.
• Production of 100,000 BOPD, high water cut.
• 80 production platforms (jackets).
• Requires up to 41 days to drill the 10,000 feet wells.

<u>Pump Requirements</u>
• Must use high strength ARZ-ZA bearings.
• High strength shaft.
• Mixed flow stages.
• Gas handler to handle 40 – 50% free gas.
• Bottom hole temperature 297 degrees F.
• High temperature motor design for up to 394 degrees</td></tr>
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<tr><td></td><td></td><td>F.
• Use high temperature gauge.

<u>Establishing Production</u>
• Had many problems to establish production.
• Very low PI reservoir, low inflow rate.
• Initially low run life due to poor motor cooling.
• Ran frac job to improve well productivity and now ESP's are performing better.</td></tr>
<tr><td>"Intelligent ESP" System Successfully Tested in Petroleum Development Oman</td><td>Cleon Dunham, Oilfield Automation

Shaikhan al Khadhori, Abdullah al Kindy, Petroleum Development Oman</td><td>This is a story about testing of the "intelligent ESP" system in Petroleum Development Oman. Nasser al Rawahy of PDO introduced the presentation. I presented the technical details.

<u>Petroleum Development Oman</u>
• Oman is located on the Arabian Peninsula.
• PDO operations are divided into North and South.
• North is mostly limestone with light, gassy crude. It has about 300 ESP's.
• South is mostly sandstone, with medium gravity, low GOR crude and some sand problems. It has about 500 ESP's.

<u>Background</u>
• Six traffic fatalities in 2000 in desert driving accidents.
• Many ESP's are very remote.
• Many must be started very slowly to avoid sand problems.
• This leads to many trips to the well and to much production deferment.

<u>Approach</u>
• Approach is to automate ESP bean up (start up) to minimize number of trips to each well and minimize deferred production.
• Instrumentation used
  o Downhole information – from Phoenix gauge.
  o Coriolis meter to measure production rate.
  o Control valve to control start-up (most wells have fixed speed drives).
  o On-line sand monitor.
• Automated operating modes
  o Pre-start system check.
  o Initial start and run – to check all components.
  o Bean-up to slowly start well with minimum surges, sand production.
  o Normal operation – to always stay within "safe" operating envelop.
  o Shutdown – to manage all shutdown conditions.
• Control strategies (options)
  o Control position of wellhead control valve to ad-</td></tr>
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Paper	Author(s)	Summary of Discussion
		just backpressure. ○ Or, control frequency of VSD. ○ Control liquid production rate by adjusting position of valve or VSD frequency. ○ Control pump intake pressure. ○ Control level of fluid above pump. ○ Control tubing head pressure. • Control logic ○ Have fully automatic back-up control if primary control mode or instrumentation fails. ○ Continuously check for any faults. ○ Manage all shutdowns, due to: ▪ Manual local shutdown ▪ Manual remote shutdown ▪ Automatic local shutdown ▪ Automatic remote shutdown ▪ Power failure shutdown ▪ Non-critical trip shutdown ▪ Critical trip shutdown ○ Allow remote control from Production Station of even from Engineering Office on the Coast. <u>Expected Benefits</u> • Reduce desert driving by up to 600,000 km per year. • Reduce production deferment by up to 900 M^3 per day (5,700 B/Day.) • Increase pump run life by up to 20%. • Support broader application of ESP's. <u>Future Work</u> • System ready for installation on low gas, sandy wells. • Work needed to manage gassy wells. • Work needed to "optimize" production once "Normal" operating mode has been reached.
Panel Discussion		
ESP Contract Strategies	Facilitator: Carol Magna-Grande **Magna-Grande Distributors, Inc.** Panel: Scott Beull, **ChevronTexaco** David Wilke, **Occidental** Noel Puetcher, **El Paso**	<u>Opening Comment</u> • Alliances have improved in the last seven years. • Note that some of the "questions" and "answers" listed below are merely brief summaries of what were sometimes lengthy statements. Also, some of them were more comments than actual questions or answers. <u>Question</u> • What types of alliances are used? • How are they kept simple? <u>Answer</u> • Use mixed types of alliances, depending on location of companies and local conditions.

Paper	Author(s)	Summary of Discussion
	Nassar al Rawahy, **Petroleum Development Oman**	• Need to include key performance indicators to "judge" success of alliance. • Need to keep alliance agreement short and simple. • Need good communications between all stakeholders. Question • How make alliances business attractive? • How compare before/after performance? • How compare buy vs. lease? Answer • With purchase, risk is with Operating Company. • PDO seeks to share risk, to improve run life. • ChevronTexaco looks at overall cost of operation. • Risk/reward relationship. If ESP runs to desired run life, Supply Company shares in cost or reward. Question • How convince alliance partners to maintain the alliance if it is successful. Management may wish to stop the alliance. Why bother? Answer • Can not only take a financial accounting perspective. • Need to understand engineering, environment, etc. • ChevronTexaco has six different alliances around the world. Question • Why are the alliances based on a key performance indicator of run life in PDO? • How about a performance indicator based on production? Answer • PDO involves the Supply Companies in evaluation of the production data to choose the correct ESP equipment. • If there is good information on the reservoir, they use a lease plan. • If there is not good data on the reservoir, they use the purchase plan. Question • What problems have occurred with alliances, and what corrections have been applied? Answer • Focus on the alliance tends to drift away with time. • Need regular meetings to keep people on track.

Paper	Author(s)	Summary of Discussion
		• Need collaboration. • Need a known base line and need to set mutually agreed targets. • People turnover can be a problem that must be addressed. <u>Question</u> • Isn't it the role of the Supply Company to provide the production system? Must have the Supplier and Operator work closely together from the outset. <u>Answer</u> • When setting up an alliance, it is good to use experience from a prior good alliance to build upon. <u>Question</u> • Can the target run life be increased to 700 days? <u>Answer</u> • It is necessary to look at the bigger picture, including production, optimization, OPEX. • And there can be other goals, such as minimizing power consumption as in CalTex. <u>Question</u> • How is the Supply Company motivated to provide longer run life? <u>Answer</u> • This shows "value" to the Operating Company and can lead to future work. <u>Question</u> • Can we conduct a poll to estimate alliance success rate? <u>Answer</u> • Of the audience, a large number have been involved in one or more alliances. • About 50% feel that they have had at least some success. • Some say that their alliance agreement allows flexibility so that the scope of the operation can be changed within the alliance agreement. <u>Question</u> • What are the "rules" of a successful alliance? <u>Answer</u> • Must have collaboration. • Must build on trust. <u>Comment</u> • Approximately half of the overall artificial lift expenditures in the world are for ESP's.

Paper	Author(s)	Summary of Discussion
		<u>Question</u> • An alliance is based on need. Once the need is met, is the alliance finished, or should it continue? <u>Answer</u> • This varies by company. • PDO is looking for continuous improvement through on-going alliances. • ChevronTexaco looks at this as a journey. <u>Question</u> • How does a horsepower (HP) target work? Isn't this involvement of the Supply Company in an Operating Company role? <u>Answer</u> • ChevronTexaco measured horsepower per barrel lifted. Target is to reduce the value of this performance indicator. • Supply Companies are showing more interest in operation of ESP's. <u>Question</u> • What leads to success in paying for performance? <u>Answer</u> • Moving to a lease agreement. • Increased run life reduces $ per year. • PDO is seeing a 10% per year improvement in run life. • Some companies keep lease payout going after reach target run life. • There is a "carrot and stick" in the agreement. <u>Question</u> • How to make certain that the alliance is always improving? • The Operating Company staffs are limited. • They are relying more and more on the Supply Companies. <u>Answer</u> • Need clear requirements from the Operating Companies. • Need more focus to develop staff in the Operating Companies. <u>Question</u> • How to handle areas where there is a focus on new development? <u>Answer</u> • Use alliances for mature fields. • Need a good baseline for a good alliance.

Paper	Author(s)	Summary of Discussion
		<u>Question</u> • How can we foster competition between Supply Companies for new ideas and new technologies? <u>Answer</u> • Use an alliance where the scope is big enough to make sense. • There must be an "out" if the alliance partner can't meet the technological needs. <u>Question</u> • When is the right time for an alliance "divorce?" <u>Answer</u> • Need skills in the Operating Company. • PDO is working to develop its staff, to enhance local Omani staff. • The industry is losing skills. <u>Question</u> • Both sides must be equal partners. • Not a traditional customer/vendor relationship. • Do people base an alliance on trust, or on commercial aspects? <u>Answer</u> • Operating Companies see alliances as partnerships. • 80% of alliances are performance based. • 20% are technology based. <u>Question</u> • Operating Companies look for Supply Companies that reflect their values. <u>Answer</u> • 40% of alliance partner selection is based on culture. <u>Question</u> • Why are there no Supply Company personnel on the discussion panel? <u>Answer</u> • They weren't invited. • So many different potential companies that the line had to be drawn somewhere. <u>Question</u> • Doesn't a focus on run life lead to a conservative ESP design? <u>Answer</u> • It is necessary to search for a balance between run life, production, performance, etc.

Paper	Author(s)	Summary of Discussion
		<u>Question</u> • Do alliances need to move to virtual companies? • Should there be a move to have the Supply Companies actually operate the fields? <u>Answer</u> • No answer recorded. <u>Question</u> • What is status of “cause of failure” analysis? <u>Answer</u> • ChevronTexaco is using this analysis, working with the Supply Companies. • PDO collects data and uses this analysis. • PDO is doing benchmarking, sharing information. • Using the ESP-RIFTS system to share information with an industry consortia of companies. <u>Question</u> • Who is responsible to introduce new technology? <u>Answer</u> • Both sides. This is a shared responsibility. <u>Question</u> • How is new technology paid for? <u>Answer</u> • It may be necessary to amend the alliance agreement for new technology. <u>Question</u> • Do agreements allow 3rd parties to introduce new technology? <u>Answer</u> • Yes, this is allowed by PDO. • Can purchase new technology under the umbrella of the alliance agreement. <u>Question</u> • Are there multi-faceted alliances for ESP and other services such as chemicals? <u>Answer</u> • There are a few. • Can build a team in one location. • Must involve field staff, engineers, management, and accounting.

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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Session IV – Case Histories Part Two</td></tr>
<tr><td>Hydraulic Workover ESP Installation</td><td>Nora Ghobrial, Shell E&P Company</td><td>This is a story about using a hydraulic workover rig to install an ESP system in an offshore, Gulf of Mexico, well. It would not have been economically feasible with a conventional workover rig.

<u>Field Description</u>
• Gulf of Mexico.
• South Marsh Island 130 Field.
• Most wells on gas-lift.
• Well A14 was a good ESP candidate.
• Plan was to install gas-lift equipment as a back-up.
• Installation of ESP could not be justified with very high cost of conventional workover rig, mainly due to extremely high mobilization costs.
• A hydraulic workover rig can be mobilized for a much lower cost.

<u>Hydraulic Workover Rig</u>
• The rig is cheaper and faster than a conventional rig.
• It is essentially a hydraulically operated snubbing unit.
• It is similar to a coiled tubing unit as far as mobilization is concerned.
• There is good availability of these units. They can be scheduled much sooner.
• One project engineer can coordinate the entire job.

<u>Economics</u>
• Cost for normal rig: $1,350,000
• Cost for hydraulic operated rig: $450,000

<u>Question and Answer</u>
• Question: What is the source of the power to operate the ESP?
    ○ Answer: There are already some ESP’s in the field and there is already ample power available on the platform.</td></tr>
<tr><td>ESP Monitoring – Where’s Your Speedometer?</td><td>Sandy Williams*, Julian Cudmore, Stephen Beattie, Phoenix Petroleum Services

* Now with Engineering Insights Ltd.</td><td>This is a story about the advantages of using downhole information to monitor and evaluate ESP installations.

<u>Rationale</u>
• Only 2% of ESP’s in the world have downhole sensors.
• Rarely is this information used to control the ESP’s.
• Downhole information can be used to provide a better perspective of ESP operation and performance.
• It can be used to help control and optimize the operation of the ESP.
• It can be used to measure the differential pressure</td></tr>
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Paper	Author(s)	Summary of Discussion
		across the pump. It is not necessary to guess this value. • It can be used to help protect the pump if there is some downhole operating problem. • It can be used to help diagnose downhole equipment and/or inflow problems. • For most effective operation, it is important to look at the entire well/pump hydraulic and electrical system.
Case History: First Field Wide ESP Installations in Saudi Aramco	Eric Lockard, Saleh Ismaila, **KCAPEU**	This is a story about installing ESP's on a field-wide basis in a "new" field in Saudi Aramco. <u>Field Description</u> • The field produces no gas. • Crude is 49 – 53 degrees API. • Temperature is 150 degreed F. • Average well depth is 6000 ft . • Production rates vary from 500 – 4500 B/Day. • There are sand problems. • The discovery well was drilled in 1989. • Peak production was 205,000 BOPD. • Sand control is provided by gravel packs and some sand consolidations. <u>ESP Issues</u> • The only major issue is the sand production. • Before the advent of sand, used floater (radial) pumps. • Sand production started with advent of water production. • Installed sand control. • Started using "sand" pumps. • Using compression pumps. • Operating in downthrust. • Average run life 2 years. <u>Failure Analysis</u> • Have had 166 failures. • Most failures have been due to downthrust. • Most failures have occurred in the seal section. <u>Current Focus</u> • Focus on training staff. • Focus on proper sizing of ESP equipment – to stay in recommended operating window. • Working for better communications between Engineering and Operations. • Developing a preventive maintenance program.

Paper	Author(s)	Summary of Discussion
Understanding VSD's with ESP's – A Practical Check-lift	Sandy Williams, Alastair Baillie, **Engineering Insights Ltd.** David Shipp, **Eaton Cutler-Hammer**	This is a tutorial about the application of variable speed drives (VSD's) on ESP systems. <u>VSD's</u> • The head generated by an ESP is a function of the velocity squared. • A VSD provides flexibility to adjust the velocity as required. • It can be used to "soft start" a well when it is necessary to bring it on line slowly to limit the initial reservoir drawdown. <u>Problems with VSD's</u> • OPEX is increased due to higher electrical usage. • They can lead to harmonic distortion in the electrical distribution system. • There can be early failures. • Harmonic distortions (fluctuations away from the sine wave) cause several problems: o Lower power factor. o Increased OPEX. o Increased failure frequency. o Increased motor and cable heating. o Increased shaft stress. • These problems can be overcome with proper design of the electrical system. o Make certain that the maximum acceptable harmonic levels are not exceeded. o Confirm the actual levels with measurements. o Check the wave form with an analyzer. o Make corrections if there are any harmonic problems. <u>Questions and Answers</u> • Question: When is a VSD is needed? o Answers: Must carefully select candidates. o Used for testing "new" wells. o For handling wells where rates change significantly over time. o For handling wells with gassy production. • Question: How is extra heating caused by VSD handled? o Answer: Need to provide proper cooling if using VSD's in the desert. • Question: How much do harmonics reduce run life? o Answers: This depends on the severity of the harmonics, and how they are mitigated. o Proper use of a VSD can actually enhance ESP run life.

Paper	Author(s)	Summary of Discussion
Analyzing and Resolving Lightening, Power Quality, and Load Limitations in the Boscan Field	David Shipp, Jim Sheppard, **Eaton Cutler-Hammer** Aidor Martinez, **ChevronTexaco**	This is a story about dealing with lightening and other power related problems in the Boscan Field in West Venezuela. Problem Description • The Boscan Field is west of Lake Maracaibo in Venezuela. • The field has about 300 km. of aerial (overhead) power lines. • There is a problem with large voltage drops to the more remote wells. • There are problems with lightening, grounding, and harmonics. • Most of the ESP's in the field use VSD's. • An overhead ground wire is used for lightening protection. Challenges • Must have a proper grounding design to avoid failures due to lightening. • Must ground to the well casing. • Must protect system from getting harmonics back through the electrical distribution system into other systems such as beam pumps. Field Expansion • Field wanted to add more wells, but couldn't expand electrical distribution system. • Was able to "fine tune" system with proper design to permit adding new wells.
Session V – Field Studies		

ESP Run Life Improvement in Harsh Elastomer Environments, the Moomba Field	Jocelyn Young,
	Santos Ltd.
	
	Gordon Kapelhoff,
	Arthur Wilson,
	Schlumberger
		This is a story about overcoming problems with very short run lives in a challenging field environment in Australia.
		
		Problem Description
		• Santos is the largest producer in onshore Australia.
		• They are operators for the Moomba gas field.
		• The field has an oil reservoir above the primary gas reservoir(s).
		• Average ESP run life is 800 days, from a depth of about 5500 feet.
		• The specific reservoir in this story:
		  ○ Temperature 268 degrees F.
		  ○ Depth 7000 feet.
		  ○ Rates about 8000 B/Day.
		  ○ Produces scale.
		
		ESP Story
		• Initial run life was 87 days.

Paper	Author(s)	Summary of Discussion
		• The average run life for the next six installations was 184 days. • Failure analysis was used to determine cause of problem. • Found that elastomers had dried. • Changed from using HSN to Aflas for the bags in the Protector Section. • First "new" design ran for only 102 days. <u>Addressing the Problem</u> • Set up two teams – one in manufacturing, one in operations. • Had significant downtime due to problems with the fuel. Fuel used to power generators. • Had harmonics in the VSD's. • Found that neither bags or labyrinths could be used in the Protectors. • Ran a new design of Protector with a heavy fluid to keep well fluids out of the motor. • Now the new run life is 421 days. <u>Conclusions</u> • Electrical failures are often due to poor quality in the power system. • Now have a new Protector design that is virtually free of elastomers, using the heavy fluid. This works as long as the well is essentially vertical. • Presenters wouldn't disclose the actual "heavy" fluid that is used.

Subsea ESP's: Expanding the Boundary of Experience	David Christmas, **Schlumberger**	This is a historical summary of the status of sub-sea ESP deployments in the world.
		
		<u>Initial Drivers</u>
		• Need for sub-sea installation of ESP's started in the North Sea.
		• There are limits to how much can be produced by gas-lift, especially on sub-sea wells that are far from the "host" platform.
		• There are a large number of discoveries that are far from the "host" platform that are not large enough to justify their own platform. Thus, they are good candidates for sub-sea completions.
		• A JIP was started in the early 1990's to progress deployment of sub-sea ESP's.
		• This led to the development of horizontal trees.
		
		<u>History</u>
		• 1994, Petrobras
		   o First sub-sea ESP in Petrobras.
		• 1996, Amoco
		   o Two year run life.

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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
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1998, Shell
Shell Gannet.
14.5 km. from “host” platform.
Run lives from 342 to 713 days.
1998, Petrobras
1100 meters deep.
1300 day run life.
Used sub-sea power transformer.
1999, Norsk Hydro
Up to 60,000 B/Day.
2000
First sea-bed separator.
2001, 2002, Petrobras
More Petrobras installations.
Riser lift using an ESP from 1350 meters.
2002, ChevronTexaco
Had failure, converted to gas-lift.
2002
Tandem ESP system, 21 km. outstep.
2003, Santos
Dual ESP’s
ESP + Framo multi-phase pump to boost production to “host” platform.

<u>Conclusions</u>

Use of sub-sea ESP’s is proven technology.
Must carefully watch success factors.
Industry has used phased approach to gradually increase depth, outstep distance, power, etc.
Many companies must be involved in a successful installation/operation. Management of the interfaces is essential.

</td></tr>
<tr><td>Benchmarking ESP Run Life Accounting for Application Differences</td><td>F. J. S. Alhanati,
T. A. Zahacy,
R. S. Hanson,
C-FER Technologies</td><td>
This is a story about the ESP-RIFTS (ESP Reliability Information and Failure Tracking System). ESP-RIFTS is a database system, operated by C-FER for a multi-member industry consortia, for collecting ESP operating and failure information, and analyzing this information. Currently there are ten member companies.

<u>ESP-RIFTS Objectives</u>

Benchmarking
Understanding the factors that affect run life.
Forecasting failure and workover frequency.
Predicting ESP run life in “new” applications and/or environments.

<u>Information Requirements</u>

Must have a large amount of quality information.
A major challenge is to assure quality information in the system.
Must all “talk the same language” across many Oper-

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<tr><td></td><td></td><td>ating Companies, operating all across the world.

<u>Statistical Analysis</u>
• Have a statistical model to evaluate the information in the database.
• It can be used to estimate run life in various circumstances.
• It can be used to benchmark one operation with other similar operations.
• There are currently approximately 11,000 records in the database.
• The model uses an exponential life time distribution.
• It also uses a proportional hazard model.

<u>Problems/Challenges</u>
• Incomplete information.
• Censored information – some records represent the full life cycle of a system; in some cases the pump is still running.
• There are a large number of possible models that can be sued to evaluate the information.

<u>Current Uses</u>
• Can compare predicted MTTF (mean time to failure) vs. actual MTTF.
  ○ This highlights systems that work better or worse than expected.
  ○ Understanding why can lead to improvements in the choice and deployment of systems.
• Can predict the distribution of “causes of failures.”
  ○ This can lead to taking proper preventive measures.
• The information can be used by a member company to predict run life in the conditions that it faces in its specific field environment.</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Breakouts</td></tr>
<tr><td>Introduction</td><td></td><td>Five different breakout sessions were held, some on Wednesday afternoon and some on Thursday afternoon. A brief summary of each breakout session was presented on Friday morning. The more detailed breakout summaries are to be installed on the ESP Workshop web site at www.espworkshop.com.</td></tr>
<tr><td>Pump Modeling, Gas Separation</td><td>Mauricio Prado, Tulsa University Artificial Lift Project (TUALP)

Francisco Alhanati, C-FER Technolo-</td><td>This breakout session focused on pump modeling and gas separation issues.

<u>The Problem</u>
• The velocity of liquid in the pump is greater than that of gas, so gas builds up in the low pressure areas in the impellers.</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
	gies	• This can lead to head degradation, surging, and gas locking. Many Concerns About This Problem • There were seven abstracts submitted in the area of problems with gassy production. • So, the decision was made to hold a breakout session on this topic. Progress is Being Made • Progress is being made in better understanding the problems caused by gassy production. • For example, TUALP has developed a new model that shows good agreement between predicted and measured behavior.

ESP Run Life and Failure Analysis	Noel Putscher, **El Paso**	This breakout session focused on ESP run life and failure analysis. Clearly, failures and run life are closely intertwined.
		
		Proper Field Procedures
		• Proper handling.
		• Proper running and pulling.
		• Proper care of pulled equipment to facility inspection and failure analysis.
		• Don't flush the motor or protector when the system is pulled. This may remove valuable evidence.
		• Don't re-use the motor flat cable.
		• Check the shaft for free rotation.
		• Visually check the exterior for:
		  o Scale
		  o Corrosion
		  o Erosion
		  o Mechanical damage
		• Test/check the motor, protector, pump.
		• Evaluate cause(s) of failures
		  o Need operational information.
		  o Fluid data.
		  o Original design information.
		
		Optimize Run Life
		• Goal is to maximize profit, not necessarily maximum run life, maximum production, or minimum failures.
		• Steps
		  o Select correct equipment.
		  o Evaluate key performance factors.
		  o Continuously monitor well production and pressure data.
		  o Continuously monitor pumping system electrical data.
		  o Conduct "cause of failure" analysis.

Paper	Author(s)	Summary of Discussion

		• Tools
		  ○ Information on the "whole" system.
		  ○ Monitor production data.
		  ○ Detect well problems – equipment and/or well problems.
		  ○ Training – both for company and contract personnel.
		  ○ Focus on technology transfer.
		• Causes of Early Failures
		  ○ Design deficiency.
		  ○ Improper material selection.
		  ○ Manufacturing faults.
		  ○ Assembly errors.
		  ○ Actual service conditions not considered.
		  ○ Operating out of the "safe" operating envelop. Remember that the pump "sees" actual in-situ volumetrics.
		  ○ Wear is a function of the velocity cubed.
		• Need a team on-site when an ESP is pulled to make certain that all pertinent failure evidence is captured.

ESP Applicability	Cleon Dunham, **Oilfield Automation**	This breakout session focused on the applicability of ESP's in different operating scenarios. <u>Secondary Recovery</u> • Produce high rates • Better efficiency than gas-lift <u>High Temperature Applications</u> • Higher temperatures than PCP <u>High GOR Applications</u> • Technology is improving • Combine separators and gas handlers <u>Heavy Oil Applications</u> • Inducer to "prime" pump stages • Applications down to 9.5 ^{0}API • Dispersion, core flow, diluent <u>High Solids Applications</u> • Problems with sand, proppant "flow back" • Special materials • Use "slow start" with VSD or choke control to start slowly to avoid surges on formation and allow solids to "stabilize." • Rates, depths beyond PCP range <u>Staff Development</u> • Need people who understand ESP's • Use training matrix, accreditation scheme • Must retain knowledge

Paper	Author(s)	Summary of Discussion

		• Alliances require knowledge from both parties
		• Need champion: maintain focus, coordinate training:
		  ○ Engineers
		  ○ Operators
		  ○ Well service personnel
		  ○ Maintenance personnel
		
		Information
		• Focus on gathering quality information – surface and downhole
		• Provide resources to understand and use
		• Use "smart" systems to process information
		• Understand "value proposition" of information
		• Consider use of industry ESP-RIFTS for evaluation of performance
		• Use automation when feasible
		
		Issues
		• Systemic design of whole well process
		• Consider full life cycle costs
		• Lack ESP "standards" (e.g. API / ISO)
		• Make better use of recommended practices (e.g. API) Improvements are being made – evolution, not revolution.

Severe Conditions	Mike Berry, **WoodGroup ESP**	This breakout session focused on selecting ESP's for severe production conditions. Challenges • High temperature. • Abrasion due to solids. Can partially overcome by using slow start with a VSD or a "choke up" approach. • Scales. • Asphaltenes. • Corrosive gases. • Free gas. • High viscosity. • Use of treating chemicals. • Poor power quality. • Mis-application of equipment. Precautions • If use VSD's, be careful not to exceed design specifications. • Be careful about shaft rotation. • Be careful not to abuse equipment.

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<tr><td>Unconventional Installations & Applications</td><td>John Patterson, ConocoPhillips</td><td>This breakout session focused on uses of ESP's in unconventional applications.

<u>Examples of Unconventional Uses of ESP's</u>
• Coiled tubing deployed ESP's.
• Coiled tubing deployed, with flow up the annulus.
• Wireline deployed ESP's.
• Wireline deployed ES/PCP's.
• Downhole boosting, with two motors, two VSD's.
• DHOWS system for downhole water separation and injection.
• De-watering gas wells.
• Surface (or sea bed) boosting.
• ESP's to pump source water to water injection wells.
• Dump floods.
• High temperature ESP's, e.g. for SAGD in Canada.

<u>Needs in the Industry</u>
• Higher temperatures.
• Higher gas handling capabilities.
• Higher sand production handling capabilities.
• Improvements for gas well de-watering.</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Closing Comments</td></tr>
<tr><td>Summary</td><td></td><td>This was the 22nd annual ESP Workshop.
• There were 294 registrants.
• There were 98 attendees from Operating Companies.
• Others were from Service Companies, Consultants, and Universities.
• Representatives came from 22 countries.
• They came from six continents.</td></tr>
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