2005 ESP Workshop

Summary of Presentations

Woodland Waterway Marriott Hotel

Prepared by
Cleon Dunham, Oilfield Automation Consulting
May 5, 2005

Paper	Author(s)	Summary of Discussion
Purpose of this Document		
		The purpose of this document is to summarize the main points of the technical presentations and panel discussions at the 2005 ESP Workshop. If you wish to learn more, please review the actual papers. The papers are included in the Workshop notebook and on the Workshop CD. If you didn't attend the workshop, you can purchase a CD from the ESP Workshop committee. These summaries are based on my notes. If anything is presented incorrectly, the fault is mine, not the authors and/or presenters of the papers. Attendance at this years workshop was: • A total of 557 people, including 499 registered attendees and 58 students from Texas A&M University, attended the workshop. • They came from 25 separate countries. • 36% were from Operating Companies, with more from Oxy than any other Operating Company. • 64% were from Service/Supply Companies.
Opening Comments Session Chair: Mike Parker, Kerr McGee		
		Mike Parker of Kerr McGee gave the opening comments. • Mike welcomed the attendees. • He gave a safety presentation and made other announcements. Thanks were given to the instructors for the 2005 ESP 101 and 102 Continuing Education Courses. • Bruce Brookbank of Centrilift. • David Devine, Consultant.

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>Chip Ollre of Schlumberger gave a special recognition to Bill Pelton who passed away on November 22, 2003. Recognition of Bill's contributions to the ESP Workshop is included in the ESP Workshop Notebook.</td></tr>
<tr><td colspan="3" align="center">Keynote Address</td></tr>
<tr><td>Evolving Oil Trends</td><td>Patrick (Pat) Oenbring
Executive Associate, Ziff Energy Group</td><td>Patrick Oenbring gave a sobering keynote address.

The ESP Workshop has wide acclaim in the industry. It serves an important role.
Comments on oil prices:

There is usually a “war time spike” of at least $15 per barrel.
Today, oil prices are at an all time high due to many factors including:

Declining reserves.
Demand in China.
Problems in Nigeria and Russia.
Weak US $.

Oil and gas prices normally relate to each other in the ratio of 6 – 8.

Comments on oil and gas demand:

Demand is 220 MBO/D equivalent today.
It will rise to 300 MBO/D equivalent by 2035, with the gas component rising to 28%.
Oil demand will grow in Asia.

US shortfall:

Currently 70% of US oil consumption is imported.
Very little gas is imported.
Imports must grow to meet demand of 20 MMBO/D equivalent by 2020.

World demand:

World demand is growing by 2.3% per year.
Oil production is decreasing by 6.0% per year.
Gas production is decreasing by 3% per year.
Huge new supplies are needed.

US oil supply:

5.6 MMBOE/Day in US.
There is some help from deep water.
There will be some help from Canadian oil sands.

Gas:

Current production is 75 BCF/Day.
Will grow to 80 BCF/Day by 2015.
Growth will be in the Rockies, in the far North, and from LNG imports.
LNG imports are 2 BCF/Day in 2004.
There are many proposed NGL plants, mostly on the Gulf Coast.
Growth in Northern gas will come from McKenzie Delta by 2009-2020 and the North Slope of Alaska. Here there will be 30 TCF by 2013.

</td></tr>
</table>

Paper	Author(s)	Summary of Discussion

		• Constraints:
		  ○ Costs have doubled from 1995 – 2004.
		  ○ Drilling and OPEX costs are up.
		  ○ There are fewer oil drilling targets.
		  ○ There are more gas drilling opportunities.
		• There is a growing focus on operational excellence:
		  ○ People are working to maximize value.
		  ○ People are focusing on the life cycle of developments – discovery, development, mid-life, and mature fields.
		  ○ The focus needs to be different in each phase.
		  ○ The early phases are capital intensive.
		  ○ The mid-life phase must focus on operational cost efficiency.
		  ○ The mature phase must focus on cost control and production optimization.
		• Opportunities:
		  ○ Better integration of operations.
		  ○ May reduce costs by 15 – 20%.
		  ○ Artificial lift optimization and failure reduction.
		    ▪ Reduce failures.
		    ▪ Integrate failure analysis.
		    ▪ Reduce failure rate by 1/3.
		  ○ Reduce maintenance costs:
		    ▪ Spend more on prevention, less on corrections.
		  ○ Automation – increase BOPD/number of staff.
		  ○ Operational excellence:
		    ▪ Stick to the strategic niche.
		    ▪ Monitor performance.
		    ▪ Use best practices.
		    ▪ Get management involved in the process.
		
		Q. What about sources of oil and gas from Mexico.
		  A. Mexico is one of biggest suppliers to US. Not open to external investment. Could increase production if it opened up to US investment.
		
		Q. What is the impact of OPEC on prices?
		  A. They are important. Right now they are placid.

Session I -— Optimization **Chairs:** **Mike Parker – Kerr McGee** **Steve Kennedy – Weatherford**		
Beyond Automation - ESP Optimization and Run Life Improvement Pro-	M. Zaruma and F. Herrera **Occidental Exploración and**	This is a story about work to enhance and take advantage of an ESP automation system in Ecuador. • Production is about 100,000 BOPD. • The field is located in the jungle.

Paper	Author(s)	Summary of Discussion

cess in Oxy Ecuador	**Producción Company**
	
	J. Fornerino
	Schlumberger
	
	S. Williams
	ALP Limited
		• A SCADA (production automation) system was installed, but was not being used effectively.
		• An effort was undertaken to make more effective use of it.
		• Initial system:
		  o Gathering a large number of readings.
		  o Producing alarms.
		  o Using CASE Services automation software and LOWIS package.
		  o There were no initial recognized benefits.
		  o There was not enough training to make effective use of the system.
		• To effectively use the system, a change in thinking is required.
		  o Initiate an in-depth training program.
		  o Move from the old to a new way of problem analysis, from charts to calculations.
		  o Make effective use of the analysis capabilities in the csLift and LOWIS software packages.
		  o Create a “new language” for use by the Operators.
		  o Change the work processes, both for Oxy and for the Suppliers.
		  o Focus on coaching.
		  o Develop specific action plans.
		  o Look at well/pump “system” performance to evaluate both the pump and the well’s inflow.
		  o Make intelligent use of alarms to recognize real problems.
		  o Use alarms to initiate an analysis procedure.
		• Oxy uses an ESP alliance.
		  o The alliance partner needs training too.
		• Findings:
		  o 65% of the wells had incorrect data in the SCADA system.
		  o 28% of the wells had previously undetected problems.
		  o 24% of the wells were operating outside of the safe operating envelope.
		  o There were many “bad” well tests.
		• Conclusions:
		  o Oxy has made ESP analysis a “core competency.
		  o They have worked to “fine tune” the alarming.
		  o They now use a “fit for purpose” design for each well, not a “one size fits all” approach.
		• Morale of the story:
		  o Automation by itself is of no benefit.
		  o Must change the way you operate.
		  o Must train and coach.
		  o Analysis is work, but it adds value.
		
		Q. What is the role of the ESP Supplier?
		A. The Supplier does most of the design and analysis

Paper	Author(s)	Summary of Discussion
		work in Ecuador. Q. What is the ideal Pump Intake Pressure? A. We calculate the pump discharge pressure stage-by-stage. We calculate the pump intake pressure and compare this with the measured PIP.
Maximizing Production and ESP Run Life through Effective and Systematic use of Downhole and Surface Information	A. Al Harthy **PDO** G. Naveda, J. Cudmore, and J. Haskell **Schlumberger UK**	This is a story about efforts to optimize production and extend ESP run life in the Wafra Field in Petroleum Development Oman. The key question is: how good is the information used to balance production with ESP performance to increase both production and ESP run life? • PDO Wafra Field: o Discovered in 1985. o Placed on gas-lift in 1989. o Converted to beam pump in 1993. o Started to install ESP's in 1999, with downhole sensors. o Secondary recovery (water flood) started in 2000. o Bubble point pressure is very low: 81 psi. • Tools for analysis and optimization: o SCADA system (Shell developed system). o Downhole sensors to measure pump intake pressure, pump discharge pressure, intake temperature, motor temperature, vibration, and electrical properties. o Analysis of ESP pump performance. o Determination of actual and potential well inflow. • Steps used in the process: o Data gathering – both surface and downhole. o Data validation. o Modeling of both pump and well inflow performance. o Analysis of problems. o Identification of opportunities for improvements. • Example of data gathering and analysis performed: o Use downhole instruments to measure static bottom-hole pressure when the pump is shut down. o Measure the pump intake pressure and calculate the flowing bottom-hole pressure and reservoir drawdown. o Validate the measured pump intake pressure vs. measured fluid levels. o Determine the pump performance by determining the differential pressure across the pump. o Use well data to analyze causes of problems. o Examples of problems found: ▪ Closed wellhead valve. ▪ Leaking plug in "Y" tool. o Examples of looking at all of the wells in the field: ▪ Found opportunities for upsizing pumps. ▪ Found opportunities for well stimulations.

Paper	Author(s)	Summary of Discussion
		• ESP optimization is a continuous process to keep the well and the pumping system in balance.

Downhole Equipment Reliability and Efficiency improvements in Cravo Norte	L. Jaramillo
	Occidental de Colombia
		This is a story about ESP equipment reliability and efficiency in the Cravo Norte Field in Colombia, near the border with Venezuela.
		• The field produces 27 MBO/D, with 96.4% water.
		• Sand is 0 – 150 ppm.
		• OPEX:
		  o 39% power.
		  o 22% service.
		  o 14% maintenance.
		  o 25% other.
		  o Of this, 50% is related to the ESP operation.
		• Priorities to improve profitability are:
		  o Optimize production.
		  o Improve electrical efficiency.
		  o Improve run life and increase MTBF.
		  o Optimize operating costs.
		• This paper focuses on electrical efficiency and equipment reliability.
		• Electrical efficiency:
		  o Use VSD's.
		  o Measure electrical usage.
		  o Calculate electrical efficiency
		  o "Key performance indicator" = Watt Hr. / Bbl / 1000 Ft. of Lift.
		  o Average was 20.87 WH/B/1000 Ft.
		  o The process is to understand the problems associated with a high indicator and the good aspects of wells with a low indicator.
		  o Poor wells:
		    ▪ Low flow rate.
		    ▪ Low load.
		  o Strategies for improvement:
		    ▪ Keep pump operation to the right of the "best efficiency point" to improve efficiency.
		    ▪ Keep operating fluid level less than 500 feet.
		    ▪ Keep the VSD at its maximum capacity.
		    ▪ On some wells, improve energy efficiency by going to ES-PCPs.
		    ▪ From 2003 to 2004, improved indicator by 8.5%.
		• Downhole equipment reliability:
		  o Use MTBF approach recommended by Bruce Brookbank.
		  o Looked at 270 wells, over 20 years.
		  o Evaluated run life data for each pump.
		  o Problems detected:
		    ▪ Pump wear due to sand production.
		• Actions taken:
		  o Use new pump metallurgy.

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>

<li style="list-style:none">o Re-do power distribution system.
Conclusions:
o To make improvements, you must know where you are today.
o Need a clear “key performance indicator.”
Future plans:
o Use more VSD’s.
o Use ES-PCP’s when production is in the range of 300 – 1500 B/D.

Q. Do some wells still require high power?
A. We don’t work on a well if it is still running. We wait until it fails before making changes.

Q. How was the fluid level limit of 500 feet above the pump chosen?
A. We use the downhole sensor to determine the fluid level.

Q. What if you have no downhole sensor?
A. Then we use the fluid level. The pump efficiency decreases if the FAP is more than 500 feet.

Q. How long have the ES-PCP’s been running?
A. So far, we have them running for one year.
</td></tr>
<tr><td>Procedure of Submersible Equipment Reliability Measurement and Experience of its Implementation</td><td>O. M. Perelman,
S. N. Peshcherenko,
A. I. Rabinovich, and
S. D. Slepchenko
JSC Novomet, Perm, Russia</td><td>
This is a story about production of ESP’s in Russia and the use of statistical analysis to evaluate their performance and reliability.

Statistical approach:
o They use probability theory, rather than MTBF.
o They use operating data to evaluate ESP performance and reliability in Western Siberia.
o They compare Complete Operating Time to the end of pump system life at an ESP failure with Incomplete Operating Time until the ESP is stopped for some reason.
o They obtain data from Russian Oil Company databases on:
▪ Run time.
▪ Cause of failure.
▪ Tear down analysis.
▪ They separate each event into failures by cause of failure, and other events.
o They define the Overall Period (OP) = Total Operating Time / Number of Failures.
o They define MTBF = Total Operating Time per Failure / Number of Failures per Year.
o This helps them to compare infant mortality with “old age” failures.
o They prefer a value called T_{05}.
o This is the estimated time to failure of 50% of the

</td></tr>
</table>

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>ESP installations.
o Based on this analysis, they have found that ESP's produced by Novomet perform and survive as well as "Western" ESP's.
o They plot the survival function T_{05} vs. time.
o This can be extrapolated to provide a run life forecast.
o They have found that most ESP failures are caused by "Operational" issues, not ESP design issues.

Q. This is a good use of failure analysis. Are most failures due to Operational problems, or to poor equipment selection?
A. It is difficult to classify the actual causes of failures.

Q. Are there other applications of this reliability method?
A. Don't know.

Q. How many Russian ESP's are installed?
A. There are about 3500 ESP's installed in Western Siberia.

Q. Why is MTBF calculation limited to one year?
A. This is the definition we use.</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Session II –-- Gassy Applications
Chairs:
Neil Griffiths – Shell International EP
Mike Hefley – TNK/BP Moscow</td></tr>
<tr><td>ESP-Jet Pump completions for High GOR Wells - A Field Study</td><td>S. Ageev and
A. Jalaev
Special Design Bureau "Cannas"

A. Drozdov
Gubkin Russian State University of Oil and Gas

V. Maslov and
M. Perelman
JSC Novomet-Perm</td><td>This is a story about use of Russian ESP's to produce gassy wells.
• ESP's in Russia:
o There are approximately 90,000 ESP's in the world.
o There are 60,000 ESP's in Russia.
o 70% of the oil in Russia is produced by ESP's.
• Problems:
o Free gas.
• Ways to address the problems:
o Use of gas separators.
o Use of gas handlers that homogenize the mix.
o Use of tapered pumps.
o Use of special stages.
o Use of the "ES Jet Pump."
• Experiences:
o There are problems with gas separators.</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		○ There are some new types of pump stages to better handle free gas. ○ Free gas is defined as the volume of free gas divided by the total volume, at pump intake conditions. • Approaches tried: ○ Centrifugal stages. ○ Centrifugal vortex stages. ○ Centrifugal axial stages. ○ The head is greatly reduced as the amount of gas increases. ○ Performance is better with the centrifugal axial design. • ES Jet Pump concept: ○ They install a jet pump above the ESP discharge. ○ They say that the jet pump helps to produce up to 75% free gas. Q. Please explain the principle of operation of the jet pump. How does this help handle more gas? A. (I couldn't understand the explanation.) There are 13 wells in TNK/BP with ES Jet Pumps.
Norman Wells Bunker ESP Installation	T. Holding **Imperial Oil Resources**	This is a story about development of the Normal Wells Field in the far north of the Canadian Northwest Territories. • The field was discovered in 1920. ○ Reservoir 400 ft. thick, 1500 ft. deep. ○ Static bottom-hole pressure is 1000 psi. ○ Bubble point pressure is 500 psi. ○ Pump intake pressure is about 100 psi. ○ Major development occurred during World War II. ○ Wells were drilled in steel bunkers to protect against ice flows during the Spring breakup. ○ Ice breakup occurs starting in mid May. ○ In the 1980, 257 new wells were drilled. ○ The wellbore is an "S" shape. ○ Initially the field was placed on gas-lift. ○ In 2002, there were 79 wells on rod pump, 7 on ESP, and 84 on gas-lift. ○ However, production rates and ultimate recoveries are improved with ESP's. • Bunker design: ○ Well design must comply with API 14B. ○ There must be a "fail safe" design in case wells are "over run" by ice flow. ○ The bunker is 12 ft. x 12 ft. x 12 ft. and made of steel. ○ The ESP's must be produced below a packer. ○ A special Christmas tree is required to fit in the bunker.

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>

Operation:

Reservoir pressure has been increased by water flooding.
The “kill” gradient to work on the wells is 13 ppg.
Both casing and tubing integrity must be provided.
The “free” gas production is on the order of 70%.
A “standard” ESP impeller will gas lock.
They use a “multi-vane” pump (MVP) design.
The MVP successfully handles 19 – 26% free gas.
They have a good SCADA system on all wells.
They are able to service their wells during six months of the year.
They use gas-lift as a back up if an ESP fails.
They use a helicopter-deployed wireline unit.

Q. Do you produce year around? How do you handle the flowlines?
A. Yes, we produce all year long. The flowlines are buried beneath the river.

Q. What is the pump intake pressure?
A. 100 psi.

Q. Do you install a retrofit gas-lift system?
A. No.

Q. Have you considered use of dual ESP’s?
A. No, back-up gas-lift is less expensive.
</td></tr>
<tr><td>Gas Separation: A New Generation, A New Twist</td><td>L. Wilson
Centrilift</td><td>
This is a story about a new gas separator design by Centrilift.

Tutorial on gas separation:

Types of rotary gas separators:
Paddle.
Rotary chamber.
Vortex.
Separation goal:
Goal isn’t to separate liquid and gas.
It is to produce a “pump-able” fluid.
Separation:
The rotary chamber method deploys centrifugal motion.
Gas separation efficiency = Volume of Free Gas In / Volume Out.
Free Gas % = Volume Gas / (Volume Gas + Volume Liquid).
Comparisons:
Which type of separator is better?
Typically, a rotary separator is better with viscous fluids.
A vortex separator is better at high flow rates and if there are abrasives present in the fluid.

</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		▪ Ideally, it would be good to have a separator design that could handle both cases. • Separator design criteria: o There must be enough pressure drop across the separator so the liquid and gas can exit the separator. o Need an inlet auger to "lift" the liquid into the separator. o Gas may form a "gas core" in the auger. o Therefore, the auger must "encourage" a mixing of the liquid and gas. o Tilted vanes are used to better mix the liquid and gas and help it pass through the auger. o The intake must be large enough to reduce velocity, reduce head loss, and improve gas/liquid separation. o The separator must have improved bearings and improved corrosion prevention. o There must be a large gas exit. Q. Will the non-rotating separator design work? A. Some way is needed to create a differential pressure across the separator to allow the gas and liquid to exit the separator. A static device will not work since it can't provide the differential pressure across the separator. Q. Is the performance of the separator limited by the performance of the auger? A. Yes. Q. Why not design the auger to handle more fluid? A. If the auger is too large, this will increase the liquid re-circulation and waste energy. Q. This is designed for 3500 RPM. What if a VDS is used? A. Performance changes at slower RPM's but can still work at lower speeds.
Short Story: Case Study - Performance Evaluation of a Helico-Axial Multiphase Pump in a CO2 Flood	B. Hirth, J. Curfew and R. Waygood **Oxy Permian** P. Julstrom, J. Miller, S. Ossia and C. Ollre **Schlumberger**	This short story and the next one were combined into one presentation. • Poseidon gas handler. o Helico-axial design. o This both generates head and conditions the fluid. • Case history in Oxy Permian: o Use downhole measurements for control. o Have very low producing bottom-hole temperature. o Use a gas separator. o Use the Poseidon gas handler. o The Poseidon uses helicon-axial stages.

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>

Normally gas accumulates on the lead edge of the impeller veins.
With the Poseidon, most of the flow is axial, not radial.
Before, wells were cycling on under load shut-downs.
Now the wells are controlled by temperature. The temperature is low, so the wells don’t cycle off and on.
The wells produce a high rate of CO_2.
They produce successfully on temperature control with the low load shutdown feature disabled.

</td></tr>
<tr><td>Short Story: Production Of Highly Gassy Wells Utilizing A Helico Axial Multiphase Gas Handler</td><td>K. Boerger
Occidental Of Elk Hills

A. Cooke
Schlumberger</td><td>
This is a continuation of the above short story. Here the information is based on experience in the Oxy Elk Hills Field.

Well conditions:

High water cut.
High gas-oil ratio.
Poseidon used in horizontal wells.
Wells completed with 5.5” slotted liners.
The wells were gas-lifted. They have been converted to ESP’s.
The ESP’s are set 1600 ft. high.
The wells produced 750 BWPD, 30 BOPD, and 1 – 2 MMSCF/Day on gas-lift.
Now they produce 950 BWPD, 35 BOPD, and 1.6 MMSCF/Day on ESP with Poseidon.
The pump is handling 60 – 65% free gas, but the production increase was not substantial, due primarily to the high pump setting depth.

Q. Did you use a simulator to predict the effect of the Poseidon before it was installed?
A. No. We installed it based on the expected improvements that could be obtained.

Q. Was a VSD used?
A. A VSD was not used. We operate at 60 Hz. The wells don’t gas lock. Shutdown is based on temperature, not underload.

Q. What is the pump intake pressure?
A. 850 psi.

Q. Is the CO_2 in the super critical range?
A. No. It enters the super critical state at about 1000 psi.
</td></tr>
<tr><td>Improving the Case for Converting a Mature North Sea</td><td>Matt Nicol
Apache North Sea Limited</td><td>
This is a story about work in the Forties Field, in the Northern North Sea.

Background:

</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
Oil Field from Gas-Lift to Submersible Pumps Using Cable Internal Coiled Tubing Deployed ESP Technology	Grant Harris **Schlumberger**	○ Tried to increase production with shallow gas-lift. ○ Wells produce with 95% water cut. ○ With gas-lift could achieve 200-psi drawdown. ○ With ESP's can achieve 600-psi drawdown. • Forties Field: ○ 5 platforms. ○ 80 wells. ○ 40 – 80,000 B/D production. ○ Need to reduce operating costs. • Why choose ESP's? ○ Can remove the gas-lift gas compressors from the platforms? ○ Can generate a high tubing-head pressure to flow the production to one treating platform. ○ It will simplify the equipment on the platforms. • Why Coiled Tubing ESP's? ○ Reduce rig time and cost. ○ Improve uptime. ○ Obtain other operating benefits. ○ Need fewer people, lower OPEX. ○ With CT, can work over in 5 days, as compared with 14 days with a rig. • Risks: ○ Corrosion. For this they use inhibitors and 13 chrome lines. ○ Sand. For this they use screens and special materials in the pumps. ○ Velocity. For this they use a large casing size. ○ Safety. They have removed the gas-lift gas. The electrical line is installed and sealed in the coiled tubing. • They run an inverted pump, with the motor on top. They produce up the annulus between the coiled tubing and the casing. • Conclusion: ○ Installed five CT-ESP's in 2005. ○ Plan to place 50% of the 80 wells on CT-ESP in the future. Q. Do you produce above the bubble point? What is the pump intake pressure? A. Pump intake pressure is 1100 – 1200 psi. Q. Do you have CT-PCP experienced, such as in Venezuela? A. Not yet. The pump power cable is installed inside the coiled tubing. Q. How do you handle sand? A. We try to eliminate the sand. We have a model to show the velocity that is needed to produce sand to the surface. If we get a lot of sand, we perform

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td>a workover using the coiled tubing.</td></tr>
<tr><td>Natural Gas Liquid (NGL) ESP Booster Pump: Kuparuk River Unit ESP Pilot Project</td><td>W. Dinkins
Centrilift

P. Bradshaw
J. Patterson
ConocoPhillips</td><td>This is a story about a novel application to pump NGL with an ESP.
• The application:
o Place ESP in a 120 ft. deep well.
o NGL flows into the annulus and down to the pump intake.
o The ESP is used to boost the pressure of the NGL so it can flow to sales.
• Advantages:
o Safety. The pump is under ground.
o Seasons. It can run all year long.
o Cost. Cost is lower, no surface equipment.
• Special issues:
o Pump design.
o Motor temperature.
▪ High horsepower load.
▪ Coolant bypass.
▪ Motor oil viscosity.
o Fluid being pumped is NGL.
▪ No bad components.
▪ Very low viscosity.
▪ PIP = 260 psi.
▪ Pump Discharge = 4000 psi.
o Problems:
▪ Bearing wear. Use compression type pump with special bearings.
▪ Over temperature on motor. Need to use a high viscosity motor oil with special additives.
▪ Use VSD with a large motor.
▪ Use a coolant bypass.</td></tr>
<tr><td>Author Panel Session</td><td>All of the authors from the presentations on Wednesday were seated in a panel at the front of the room.</td><td>The audience was invited to raised questions on any issues related to the presentation topics of the day.

Q. Horizontal wells often produce slugs of liquid and gas. How can this be handled?
A. With use of a VSD:
o Control the well in the “current” mode.
o Consider using a control valve at the surface.
o Consider using a special pump such as the Poseidon gas handler.
o Consider using a stinger in the horizontal portion of the well to encourage stable inflow rates.

Q. Would some form of downhole control be feasible?
A. Answers:
o Consider a plumbing solution. Keep the gas from gathering in the high spots in the hori-</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		zontal leg. ○ Consider using an inverted shroud to allow the pump to "live though" the periods of gas slugs. ○ Consider increasing the pump speed to process the gas slug. ○ Or, consider slowing the pump speed to only pump the liquid. ○ Keep a close eye on the current. Q. What are the advantages of the ESP + Jet Pump concept? A. The ESP allows a high flow rate and is high efficiency. The jet pump "injects" the gas back into the tubing. Q. How far is the jet pump above the ESP discharge? A. About 300 meters. Q. How does the jet pump help the ESP to better handle the gas? A. No answer given. Q. Isn't a jet pump is used at the surface in Canada? A. It is used to help "evacuate" the casing of gas. Q. What if there are solids in the jet pump "power" fluid? A. No answer given. Q. Are the tests in Russia done with water and air? A. Yes, but we use a model to predict the effects of real oil and gas. Q. A Poseidon can handle up to 75% free gas. What if the PIP is large? A. This depends on the well conditions. At 65% free gas, the Poseidon doesn't gas lock, but it will shutdown on high temperature. Q. We hear about many correlations for determining how much gas can be handled: Turpin, Dunbar, Coleman. Which one is best? Is this based on field conditions? A. Some tests have shown that the Turpin method is OK. Normal wells will follow the Turpin correlation. Possibly this needs to be field calibrated. Q. What downhole data is needed for ESP analysis? A. Need to take a "systems" approach. ○ Need to look at both intake and discharge conditions.

Paper	Author(s)	Summary of Discussion
		○ Separate well inflow analysis from pump analysis. ○ Measure or calculate pump discharge pressure, calculate pressure rise across the pump, and compare calculated pump intake pressure with measured PIP. ○ Use measured and calculated PIP to determine flowing bottom-hole pressure and compare with static bottom-hole pressure to calculate reservoir pressure drawdown. ○ Use the Shell Fieldware package or the CASE csLift package for analysis. ○ Consider any constraints on drawdown. ○ Use pressure measurements when the pump is stopped to perform a pressure build-up. Q. How can you measure flow rate in real time? A. Calculate the pressure rise across the pump and relate this to flow rate. Q. How do you perform a “top down” analysis? A. Calculate or measure the pump discharge pressure. Consider the amount of free gas in the pump. Q. Please discuss pump deployment options. A. Options: ○ Deploy the ESP on cable. Produce up the annulus. ○ Use coiled tubing with the cable external to the coil. Produce up the coil. ○ Use coiled tubing with the cable inside the coil and produce up the annulus. ○ This protects the cable and the friction is low when producing up the annulus. ○ Use wireline. This has been done in SE Asia by Shell. They can run and pull the ESP for maintenance. Q. Proactive workovers – who does it? A. Examples include Petroleum Development Oman and Oxy in Ecuador. PDO uses this to upsize and downsize their ESP’s, as required. Q. Can a combination ESP and Jet Pump help reduce the number of pump stages needed? A. No answer given. Q. What are advantages of ES-PCP vs. rod-driven PCP in viscous crude or emulsions? A. Answer: ○ ES-PCP is used in Venezuela.

Paper	Author(s)	Summary of Discussion
		○ The efficiency of both methods is similar. ○ There are 70 ES-PCP's in the Mukhaisma Field in Oman. They have a three-year run life. ○ The ES-PCP is preferred in deviated wells. ○ Rod-driven PCP is OK in shallow and/or straight wells. Q. Please discuss wireline deployment of ESP's and PCP's. A. Answer: ○ Wireline deployed PCP's have been run successfully in Alaska. ○ They have been in use for 5years. ○ Up to 8 separate PCP pumps have been installed with the same motor. ○ For big pumps, the key issue is torque. ○ Wireline-deployed ESP's have been used in Alaska. ○ They have had a three-year run life.
Session III –-- Alternate Pumping, Electrical **Chairs:** **Nasser al Rawahy – Petroleum Development Oman** **Ken Lacey – Custom Submersible and Electrical Services**		
Redundant ESP System in 7 inch Casing: Optimizing Production by Extending ESP Run Life in Marginal Offshore Oil Wells	F. Ireland and J. Ferreira **Centrilift** Raul Jose Gadelha **Petrobras**	This is a story about use of redundant ESP's in 7-inch casing in Petrobras, in Brazil. • Goals: ○ Reduce OPEX, CAPEX. ○ Increase production. ○ Have close cooperation between the Operating Company and the Service Company. ○ Use teamwork. • The project: ○ Offshore field in Petrobras. ○ Two platforms. ○ Three wells with 7-inch casing, one with 5.5-inch. ○ Were using PCP's. ○ Converting to ESP's. • Limits: ○ Difficult to obtain rigs. ○ Up to four month wait time for a rig. ○ Platforms require electrical generation. ○ PCP run life: 1 – 1.5 years. ○ Need to produce 25,000 B/D. • Challenges for the ESP's: ○ Need to be low cost. ○ Need to replace PCP Christmas trees to accommodate dual ESP's.

Paper	Author(s)	Summary of Discussion
		◦ Need to remove electrical generators and add electrical distribution from shore. This required a 7 km. sub-sea cable. ◦ Expect system run life of 2.5 – 3.0 years with single ESP's. Can improve this to 3.5 – 4.0 years with dual, redundant ESP's. • Redundant system design: ◦ Use a "Y" tool. ◦ Use an inverted cone. ◦ This is not a booster system, but a redundant system. • Typical well: ◦ 4000 ft. deep. ◦ 50% water cut. • Solution: ◦ Well too small to use "Y" tool. ◦ Production from the lower ESP must bypass the upper ESP. ◦ When using the upper ESP, production is straight to the surface. ◦ The O.D. of the ESP motor is 4.5 inches. ◦ A downhole sensor is used to monitor the well. It is mounted above the upper ESP. ◦ Use a VSD. ◦ Install a capillary line to inject treating chemical. ◦ Wellhead has a special design with 10 3/8" ports for cables, capillary tube, etc. ◦ The telemetry is linked into the Petrobras telemetry system. • Installation: ◦ Installed in October 2002. ◦ The upper ESP is run for 2 hours, once each three months, to check it out. ◦ Normally, the lower unit is run. • Results: ◦ 60% increase in production vs. previous PCP's. ◦ So far the run time is doubled vs. the PCP experience. Q. Please describe the failure the swedge lock during the initial test. A. The failed unit was replaced and has not been a problem in the actual operation.
BP Wytch Farm Install Their First Dual ESP System	P. Duffy **BP** R. Mackay, D. Whitelock, and E. Jamieson **Schlumberger**	This is a story about the use of dual ESP's in the BP Wytch Farm Field in the U.K. • History: ◦ Schlumberger has installed over 60 dual ESP's in the world. ◦ In most cases, one ESP is run and the other is held as a back up. • Wytch Farm:

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>
<li style="list-style:none">
Wytch Farm installed its first dual ESP in Sept. 2004.
Wytch Farm is in a very environmentally sensitive area.
It is the largest onshore oil field in Western Europe.
The field has 8 production sites.
It has 57 production wells and 26 injectors.
First production was in 1960.
BP has planted 132,000 trees to help keep the environmental décor of the location.

First dual ESP well:
The first dual ESP well is on Furzy Island.
The initial ESP failed.
BP then installed a jet pump, but it only produced 600 B/D.
So, an ESP was reinstalled. A back-up ESP was installed to extend the run life.
BP expects the well’s productivity to change over the pump’s run life.
The two ESP’s are installed with two “Y” tools.
There is a bypass tubing string for the lower ESP.
The well has 9 - 5/8” casing. Series 540 ESP’s are used.
The bypass tubing is 2 - 7/8”.
Downhole sensors are used, one below each ESP.
The lower ESP is run first.
This was tested in a test well.
Production was 2400 BOPD.

Q. Why do you run the lower ESP first?
A. This is designed to handle the current well conditions.
Q. Do you test the upper ESP in place?
A. No. An isolation sleeve is run in place so we can’t produce the upper ESP without pulling the isolation sleeve.
Q. Are more systems planned in the future?
A. Yes.
Q. Do you have any history with handling solids?
A. No. There are no solids produced at Wytch Farm.
</td></tr>
<tr><td>Field Comparison of Different Adjustable Speed Drive Topologies for Use on Submersible Pumps</td><td>R. Turney
Oxy - Permian

K. LeDoux
Toshiba</td><td>This is a story about improved variable speed drives for ESP’s.
Introduction:
To drive an ESP with a variable speed drive, electrical current is changed from AC to DC and back to AC.
</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
	C. Salmas **Schlumberger**	○ The degree of harmonics can be reduced by increasing the number of pulses, up to 24 pulses. • Field test: ○ A 24-pulse unit was tested in the Synder Field, in West Texas. ○ There were harmonics in the system that were induced from other wells in the field. ○ A 6-pulse system had high harmonics. ○ A 24-pulse system created much lower harmonics – both of current and of voltage. ○ The 24-pulse system pulled less KVAR power. • Conclusions: ○ The more pulses, the better the performance. ○ Pulse-width modulation is more efficient. ○ The system must have surge protection. ○ The drive can detect backspin and stop it. Q. Was the test conducted on a motor at the surface? A. Yes. And surface conditions are different than downhole conditions for an ESP motor. Q. Was frequency an issue? A. No. Unit was tested from 30 to 60 Hz. Q. How is backspin detected? A. The unit checks the frequency. The drive can stop the backspin.
Surface Electrical Reliability & Efficiency Improvements in Cravo Norte	H. Morales J. Gomez **Occidental de Colombia**	This is a story about work in Colombia to improve the reliability and efficiency of ESP systems. • Cravo Norte Field ○ 272 wells. ○ 2 production facilities. ○ Production of 550,000 BO/D and 2.1 MMBF/D. ○ Have an electrical grid plus electrical generation at two facilities. ○ The distribution system runs at 34.5 KV. ○ Electricity is used in the facilities. ○ There are 225 VSD's. ○ There are 42 across-the-line starters. ○ There are 5 soft starters. • Problems: ○ High harmonics. ○ Low power factor. ○ Terrorist attacks. ○ New VSD's – lead to increases in power losses due to low power factor. ○ Have power line failures. ○ Have voltage fluctuations. • Goals: ○ Reduce downtime, and OPEX and maintenance

Paper	Author(s)	Summary of Discussion
		costs. o Costs are very sensitive to electrical reliability. • Solutions: o Simulate the system. o Validate the expected results. o Replace some VSD’s. o Reduce harmonics. o Replace 6-pulsse drives with 12-pulse drives. • Actions taken: o Took actions based on expected benefits from simulations. o Replaced 11 heavily loaded VSD’s. o Installed 63 transformers. These are 50 MVA transformers. o Reduced harmonics from drives. o Expanded distribution system, and monitor the system. • Results based on these actions: o Achieved 55% reduction in harmonics. • Work on power lines: o Prioritized maintenance on lines. o Classified events. o Addressed each type of event. o Performed routine inspections and preventive maintenance. • Results: o Reduced deferred production. o Improved power factor from 0.85 to 0.92. o Reduced harmonics by 40%. o Reduced deferment by 350 BOPD. o Increased production by 275 BOPD. o Reduced O&M costs by $625,000 per year. o Reduced failure rate by 50 – 90%. Q. How did you increase production? A. By less downtime and more efficient production. Q. Why are you using VSD’s in a mature field? A. This is a water flood with wells 8 – 10,000 feet deep. Need ESP’s to achieve the desired production rates. Need VSD’s for operational reasons – to start at a low frequency and increase as the well continues and the pump wears out. Q. How did you get management approval for this project? A. This was based on the problems we were having with the power supply, the low power factor, and the high harmonics. Management quickly saw the need for the project, and the benefits.
Variable Frequency	D. Pettigrew	This is a story about use of variable speed generator for

Paper	Author(s)	Summary of Discussion

Generator as the Power Supply for an ESP	**Nexen**
	
	A. Limanowka
	Canadian Ad-vanced Inc.
		an ESP power supply in Yemen.
		• The variable speed generator:
		  ○ Variable frequency and voltage.
		  ○ 900 – 2000 RPM.
		  ○ 30 – 62 Hz., or 38 – 75 Hz., or 45 – 90 Hz.
		  ○ 400 – 5000 volts.
		  ○ Eliminates use of a VSD.
		  ○ It is simpler.
		• When use a VSD.
		  ○ Can have soft start.
		  ○ Can vary speed.
		  ○ But, have “dirty” power.
		  ○ Generate heat.
		• When use a switchboard.
		  ○ Simple.
		  ○ Power susceptible to source problems.
		  ○ Big inrush current on starts.
		• New Variable Speed Generator can give advantages of both:
		  ○ Pure power.
		  ○ Speed control.
		  ○ Soft start.
		  ○ It has a “brain” to control frequency, voltage, or current.
		  ○ It can be powered by diesel or natural gas.
		  ○ It can be connected to a SCADA system.
		• Benefits:
		  ○ Clean sine wave.
		  ○ Variable frequency.
		  ○ No harmonics.
		  ○ High power factor.
		  ○ Variable voltage.
		  ○ Soft start.
		  ○ High torque.
		• Field results in Yemen.
		  ○ Had a VSD.
		  ○ Ran at 57 Hz. Produced 18,250 B/D.
		  ○ Ran variable speed generator at 59 Hz. Produced 19, 500 B/D at
		  ○ This was at the same amps.
		• Advantages:
		  ○ Improved run time.
		  ○ The unit is easily movable to other wells.
		  ○ Soft starts.
		  ○ Longer life – it runs cooler.
		• Scope in Yemen:
		  ○ 360 wells.
		  ○ 240 generator sets.
		  ○ 1 new variable speed generator, so far.
		
		Q. What is the type of generator?
		A. Synchronous.

Paper	Author(s)	Summary of Discussion
		Q. Can you perform a "rocking start" if the pump is stuck? A. Yes, can restart as needed. Q. What is needed at the surface? A. The generator and the ESP controller. Q. What is the cost vs. the cost of line power? A. The cost is lower than for a generator set. It can run on natural gas. Q. What is the cost comparison of you have source power? A. The target application for this is in remote fields where there is no source power. In Yemen, use of generators is more economical than installation of high lines. Q. Could you use this with a FSD and a soft starter? A. Yes, but you would lose the ability to optimize the well.

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td></td><td></td><td></td></tr>
<tr><td>Short Story: ESP Power Quality Check: Field Case Study</td><td>K. Gohary
A. Al-Bemani
A. Al-Mahrouqi
K. Ellithy
I. Metwally, and
A. Al-Busaidy
PDO</td><td>This was a study conducted by Sultan Qaboos University and Petroleum Development Oman.
• The study:
○ The purpose was to classify field electrical problems.
• Harmonics:
○ Measure harmonic disturbances.
○ No harmonic filter was installed on the VSD's.
○ <u>Recommendation</u>: Install harmonic filters.
• Voltage and current unbalance:
○ Detected too high unbalances.
○ Unbalance limits were set too high.
○ <u>Recommendation</u>: Set unbalance limits properly.
• Grounding:
○ Found some systems that were not properly grounded.
○ <u>Recommendation</u>: Fix grounding problems.
• Transient Voltage Surge Suppression (TVSS):
○ Some wells had no TVSS.
○ Some were not within specifications.
○ Some were not working correctly.
○ <u>Recommendation</u>: Fix the problems.
• Results:
○ Significantly reduced the number of electrical trips.

Q. What is the location of the TVSS?
A. This is based on the SQU recommendation.

Q. Is the ferro-residence OK in the system?
A. This is being checked.

Q. Why do you ground the power system?
A. It is not a solid ground to the ESP system.

Q. What is there is a high ground resistance?
A. This is under discussion.</td></tr>
<tr><td>Committee Introduction and Presentation</td><td>Shauna Noonan
ConocoPhillips
General Chair for the Workshop</td><td>Shauna Noonan introduced each person on the Workshop Permanent Committee and the Rotating Committee.

The members of the Rotating Committee have been asked to stay on a bit longer since the workshop will be going to an every other year format. The next workshop will be held in 2007.</td></tr>
<tr><td></td><td></td><td></td></tr>
</table>

<table>
<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 -— ESP Surveillance and Equipment Optimization
Chairs:
Mark Johnson – ExxonMobil Production Co.
Tom vanAkkeren – Production Technology Associates</td></tr>
<tr><td>Monitoring Inflow Distribution Below Electric Submersible Pumping Systems utilizing Fiber Optic Distributed Temperature Sensing and Thermal Modeling</td><td>G. Brown and
V. Carvalho
Schlumberger

D. Smith and
M. Toombs
Oxy Permian</td><td>This is a story about monitoring the flow below an ESP intake by using a fiber-optic temperature sensor.
• Target type of well:
  ○ Well has no “Y” tool.
  ○ No room for a by-pass string.
  ○ Want to know the inflow profile.
  ○ Want to evaluate reservoir sweep.
• Target field:
  ○ Cogdell Field.
  ○ Operated by Oxy.
  ○ North of Sacroc Field in West Texas.
  ○ Developed as a pattern flood with four producers and one injector in a pattern.
• Installation:
  ○ ESP installed at 5900 ft.
  ○ TD is 7000 ft.
  ○ The fiberglass is run in a ¼” tube.
  ○ It is installed below the ESP on a sucker rod.
• Operation:
  ○ A pulse of light is sent every 10 nanoseconds.
  ○ It can measure the temperature at three-foot intervals.
  ○ The distance to each temperature measurement is the function of the speed of light in the fiber.
• Use:
  ○ By looking at the temperature profile, can see where fluid is entering the wellbore.
  ○ Build a “Therma” model to estimate the amount of inflow from each zone.
  ○ Can plot the temperature profile vs. time in three dimensions (3D) to see changes over time.
  ○ Can also determine the injection profile in an injection well.
  ○ This helps to understand both production and injection profiles, and therefore sweep efficiency in the reservoir.
  ○ This should result in increased reservoir recovery.

Q. Did you measure the fluid level in the well?
A. Can see the fluid level change with the change in the temperature profile.

Q. Have you calibrated the temperature profile vs. a pressure survey when the well has a “Y” tool?
A. No.</td></tr>
</table>

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td></td><td>Q. If a well is producing or injecting only water, can you see it?
A. Yes, in some cases. It depends on the temperature of the water.</td></tr>
<tr><td>ESP Selection Optimization: A Reservoir Engineering Outlook</td><td>A. Al-Qahtani
Saudi Aramco</td><td>This is a story about considering reservoir parameters when selecting an ESP.
• Normally, an ESP is selected based on current and forecasted performance data.
• Want to also consider changes in planned reservoir production scenarios.
• Issues to consider:
o There may be an early ESP failure.
o Need to consider total dynamic head, pump intake pressure, and friction.
o Want to keep the ESP operating within its desired operating envelope.
o Should consider both stable and unstable pump curves.
o Need to match the ESP Head Curve to the well’s IPR curve.
o Need to account for expected changes in the reservoir performance.
o Must run downhole sensors.
o Must also measure surface parameters.
o Normally perform a “base” design, and then adjust for expected reservoir parameter changes.
o Need to forecast changes in reservoir parameters such as water cut, pressure, gas/oil ratio, etc.
o Map various reservoir characteristics on “maps” of the reservoir.
o Look for reservoir “hot spots” where important events are occurring.
o Determine rate of change of key reservoir parameters.
o Based on all of these parameters, select the optimum pump and surface equipment.
• Recommendations:
o Base designs on “stable” pump curves.
o Use the maximum number of stages that is possible.
o Optimize the production rate.
o Match the pump’s performance to the well’s IPR.

Q. Is there good cooperation between Reservoir Engineers and ESP Engineers?
A. This is starting to happen.

Q. If operate with “unstable” pump curves, can this lead to failures?
A. This was a theoretician example. But unstable operation should be avoided.</td></tr>
</table>

Paper	Author(s)	Summary of Discussion

Well Testing on Heavy Oil Reservoirs Using Electric Submersible Pumping Systems in Offshore Mexico	E. Poblano,
	A. Salazar and
	A. Calderon
	PEMEX
	
	D. Corona and
	A. Sanchez
	Schlumberger
		This is a story about testing heavy oil production wells in the Bay of Campeche in Mexico.
		• Field conditions:
		  o Water depth is 200 – 680 meters.
		  o Field is 145 km. offshore.
		  o Oil gravity is 13 °API.
		• Objectives:
		  o Determine reservoir parameters on exploration wells.
		• Test configuration:
		  o Gather production data with a portable ESP unit.
		  o Run downhole gauges.
		  o Run the ESP in an enclosed module.
		  o Produce the well's liquids to the surface.
		  o Measure reservoir properties based on PIP, draw-down, and fluid properties.
		• Results:
		  o °API varies from reservoir to reservoir.
		  o Flow rates vary from 50 – 7000 B/D.
		  o Viscosity varies a great deal.
		  o Normal condition is 80 °C, 400 centipoise.
		• Conclusions:
		  o Were able to use a real-time communication system to transmit test data to an onshore facility.
		  o Need downhole heating to reduce the viscosity so the oil can be produced at reasonable rates.
		  o We were able to learn a great deal about the reservoirs with the test program. Many learning's were not expected.
		  o This type of test required good teamwork between PEMEX and the Service Companies.
		
		Q. Did you need to latch and re-latch the sub-sea system?
		A. We expect to, but haven't done so yet.
		
		Q. How long was the well test? Why not try a jet pump?
		A. We have no liquid storage, so the duration of the test is short. We haven't tried a jet pump. It would be hard to manage the power fluid injection offshore.
		
		Q. Have you considered ES-PCP?
		A. The reservoirs are too deep for PCP.
		
		Q. How was the equipment after the test?
		A. The pump was destroyed. The pump size was incorrect.

Paper	Author(s)	Summary of Discussion

Correct Application of High Rate ESP's in Saih Rawl Shuaiba Field. The Artificial Lift Health Check - Petroleum Development Oman.	B. Koksaloglu,
	A. Al-Bimani, and
	N. Al-Rawahi
	PDO
		This is a story about application of ESP's in the Saih Rawl Field in Petroleum Development Oman.
		• Field description:
		  ○ Horizontal completions.
		  ○ Field is under water flood.
		  ○ The reservoir pressure is above the bubble point pressure.
		  ○ Flowing bottom-hole pressure is about 4000 kPa.
		  ○ The bubble point pressure is about 1000 kPa.
		  ○ Proper injection and production control is required to prevent "short circuits" in the reservoir.
		  ○ Production rates vary from 350 – 2250 M^3/Day.
		• Gas-lift vs. ESP comparison:
		  ○ Max. production rate on gas-lift is 450 M^3/Day.
		  ○ ESP can produce 200 – 3000 M^3/Day.
		  ○ ESP has more advantages than gas-lift.
		• Compare ESP cost to gas-lift cost:
		  ○ ESP's can be purchased or leased.
		  ○ Gas must be compressed and there are high gas-lift maintenance costs.
		  ○ Gas-lift is better at low rates of less than 350 M^3/Day.
		  ○ ESP is better above 350 M^3/Day.
		  ○ The economic limit with ESP is lower than with gas-lift.
		• Real-time monitoring:
		  ○ Use downhole sensor data.
		  ○ Evaluate reservoir fractures.
		  ○ Want to inject water into the matrix of the reservoir rock.
		  ○ It is sometimes necessary to bean back wells to keep the reservoir fractures closed.
		  ○ Even so, can produce more oil this way than if water is injected into the fractures and bypasses much of the oil.
		  ○ Use downhole data to analyze ESP performance.
		  ○ Detect pump problems and conduct preventive pump replacements when necessary.
		  ○ Detect cases of re-circulation due to a hole in the tubing.
		  ○ Saw high pressure and temperature, so concluded that there was a hole just above the pump. The hot fluid was being re-circulated and heating the pump motor.
		• Training:
		  ○ Train both ESP and other people in the organization.
		  ○ Avoid aggressive drawdown – keep the operation slow and steady.
		  ○ Improve ESP designs.
		  ○ Perform continuous monitoring and use a proactive approach to address detected problems.

Paper	Author(s)	Summary of Discussion

		• Results:
		  ○ Have improved ESP run life from 450 to 600 days.
		  ○ Like the "traffic light" approach where the SCADA system flags wells as green (OK), yellow (warning), or red (action needed). This helps in the routine surveillance.
		
		Q. Where did the use of the "traffic light" come from?
		A. From Shell.
		
		Q. How do you design for different reservoir properties?
		A. There are uncertainties. We design for a range of conditions.
		
		Q. Do you use PI or IPR?
		A. We use PI on high water cut wells.
		
		Q. How do you analyze your ESP data?
		A. We evaluate using the (Shell) SCADA system. And we do some analysis manually.

Surface Electrical Equipment Selection Guidelines to Improve ESP System Run-life	P. Doherty
	Schlumberger
		This is a story about using statistical analysis to help select ESP surface equipment.
		• Goals:
		  ○ Long run life.
		  ○ Low OPEX.
		  ○ Minimize failures to reduce workover costs, deferred oil, personnel costs, and ESP costs.
		• Approach:
		  ○ Use statistics to identify solutions to increase run life.
		  ○ Optimize use of fixed speed drives vs. variable speed drives.
		  ○ Generate a clean 60 Hz sine wave.
		  ○ Recognize that can get harmonics if use VSD.
		  ○ This is bad if have resonance.
		  ○ Occurrence of resonance can "kill" an ESP.
		  ○ Want to eliminate harmonics.
		• Data for analysis from Reda Equipment Manager (REM) database.
		  ○ Have 23,000 data sets in database.
		  ○ 12,000 ESP's.
		  ○ 11,000 VSD's.
		  ○ Use Weibull analysis.
		  ○ Determine MTBF.
		  ○ Determine survivability function.
		  ○ Use Kaplan Meier Production Limit Estimator.
		  ○ Need a sample size of 50 or more.
		• Evaluations performed:
		  ○ Sine wave vs. 6-step.
		  ○ Plot survivability function.

Paper	Author(s)	Summary of Discussion
		○ The sine wave is always better. ○ Can predict life expectancy with survivability function. Q. What about use of a switchboard (FSD)? A. It is used in PDO. Can perform a plot of survivability function for this too. Q. What is the influence of high pressure, temperature, frequency, etc.? A. These can be analyzed too, but this hasn't been done in this paper. Q. What about the 6^{th} harmonic? A. Don't know. Q. What about 6-step vs. PWM? A. There has been more use of PWM in recent years. Q. Why do you need 50 samples for statistical significance? A. With this sample size, it is possible to predict the likely run life.
New Retrievable ESP Packer Enhances Applicability for North Sea Operators	T. Robb, D. Mitchell, S. Leyton, and R. Falconer **Halliburton** G. Whyte **Shell E&P** D. Clark and E. McIntosh **CNR International (UK)**	This is a story about a new ESP packer used in the North Sea. • This is for wells that produce 15 – 20,000 B/D. • Packer requirements: ○ Must be retrievable. ○ Must have a large operating envelope. ○ Must be simple. ○ Must have a minimum number of leak paths. ○ Must contain bores for the ESP cable. ○ Must withstand 5000 psi above, 4000 psi below, at 325 ^{0}F. • Design: ○ Has barrel slips. ○ Can carry load over 360^0. ○ Has a good seal. ○ Has feed through for tubing, cable, and control line. • Recovery: ○ Has shear rings. ○ Can cut out if necessary with a chemical cutter. • Test: ○ Conducted an ISO 14310 V3 test. ○ Ran in a test well. ○ Ran a pull and release test. ○ Ran shear ring tests. ○ Ran packer flow tests. ○ Max. run speed 120 ft./minute.

Paper	Author(s)	Summary of Discussion
		○ Max. recovery speed 30 ft./minute. • Conclusions: ○ Testing contributed to the success. ○ The packer is successful. Q. Do you swab the packer out of the hole when the pump is pulled? A. The pump design should prevent swabbing.
Author Panel Session	All of the authors from the presentations on Thursday were seated in a panel at the front of the room.	The audience was invited to raised questions on any issues related to the presentation topics of the day. Q. What are the primary challenges to produce heavy oil in deep wells offshore? A. We are looking into use of thermal heating. There is a problem with the high viscosity of the oil. Q. Looking at gas-lift vs. ESP's. ○ Need to consider reliability. ○ Need to consider the number of rigs in the field and the time to wait on a rig. A. We look at equipment cost, assuming a 1.5-year run life. ○ We run two hoists (rigs) in the field. ○ Our normal wait time for a hoist is five days. ○ Therefore, we schedule proactive ESP replacements. Q. Can you please discuss more on FSD vs. VSD vs. Variable Speed Generator. A. Answer: ○ A sine wave is the best. ○ Can use a filter on the VSD. ○ Can consider a solid state drive if can't get good fuel gas quality. ○ We use a VSD if we don't know the capacity of the well vs. the reservoir. ○ If we do know, we use a FSD. ○ The quality of VSD's is improving. ○ Harmonic free drives are more expensive than 6-pulse drives. ○ But pulse drives can affect the entire field. ○ VSD's give more flexibility for the future. ○ Yemen has 240 wells with generator sets. ○ When high lines are used, VSD's affect the other wells on the system. Q. How many dual ESP's are installed worldwide? What is their reliability vs. singles? A. Answer: ○ Don't know. ○ The 2nd ESP is valuable if the 1st ESP suffers

Paper	Author(s)	Summary of Discussion
		a premature failure. o There are currently 8 dual ESP's in Yemen. o We run both of them together. o We run 600 HP on bottom and 1000 HP on top. o We produce up to 25,000 B/D. o Bruce Brookbank looked at power effect on run life. It will take 5 years to get an answer. Q. For the Variable Speed Generator, how clean does the fuel gas need to be? A. Answer: o If the gas BTU content is too high, it won't work. o We don't use sour gas. o In some cases, we use gas directly from the well. o We have to drop the gas pressure. o We need to be concerned about hydrates. Q. If use gas-lift, you can recycle the gas? A. Yes, but there is cost to compress the gas. Q. What is the reliability of the back-up pump? A. No answer. Q. Do you consider dual ESP's for large production rate wells? A. Answer. o We try to include a capillary line to inject chemical for scale treatment. o We want the run life of a dual ESP to be at least 1.5 times the run life of a single ESP. o We design to handle sand, if needed. o Materials are much improved these days. o Now we have hard stages that are OK with sand. Q. Have studies been performed on the shaft to determine how it will withstand harmonics? A. Work on shafts is to handle load. To avoid harmonics, avoid operating at the wrong speed. Get past the "bad" speed very fast. Q. Can you use dual ESP's in sandy production? A. EnCana produces large amounts of sand. Q. Please say more about sample size. A. The larger the sample size, the less the uncertainty in the statistics. To make this work, it is essential to clearly define "failure" and "run life."

Paper	Author(s)	Summary of Discussion
		Q. Please discuss use of downhole sensors with dual ESP's. A. In Petrobras, we use one downhole sensor for two ESP's. Q. How do you evaluate the impact of the VSD on the system? A. Answer: o Everyone should conduct a full system analysis. o Everyone has similar problems. o Look at grounding, current leakage, damaged transformers. o There are more than 750 wells on ESP in PDO. o Most use Fixed Speed Drives. o Average run life is 500 to 900 days. o We use VSD's when we are uncertain about well's productivity. Q. In PDO, most wells use FSD's. Harmonics are not a problem. However, don't you need to consider all other electrical issues? A. All electrical issues are important. Q. What is the impact of harmonics on the sine wave? A. Maximize the number of pulses to minimize harmonics. Harmonics increase motor temperature. Q. If an FSD were to cost $1, what is the relative cost of 6-step, 12-step, 24-step, sine wave? A. A VSD costs 2 to 3 times as much as a FSD. Q. What causes the power factor to go down? A. Poor electrical system design. Insufficient capacitance. Q. Please say more about the ESP packer. A. A packer is required in the North Sea. We need to size the tapered tubing string to be compatible with the packer.
Session V -— Low Producers, Heavy Oil **Chairs:** **Gabriel Diaz – ChevronTexaco** **Malcolm Rainwater – WoodGroup ESP**		
Locating ESP's in Coal Bed Methane	R. Lannom **Centrilift**	This is a story about using ESP's to dewater coal bed methane (CBM) wells.

Paper	Author(s)	Summary of Discussion

Wellbores for Optimum Dewatering	B. Holmes
	Marathon Oil Co.
	
	B. McElduff
	John Wright Company
		• The amount of coal bed methane worldwide is huge.
		  ○ Some 702 TCF (trillion cubic feet) of gas has been identified.
		• CBM in the U.S.
		  ○ It is a major industry in the U.S.
		  ○ Currently, CBM accounts for more than 10% of the gas produced in the US.
		  ○ There are 8000 CBM wells in the U.S. today.
		  ○ The gas is used as a natural gas fuel and to fuel power plants.
		  ○ There are significant environmental concerns, especially having to do with disposal of the produced water.
		  ○ The “hot bed” of CBM activity in the U.S. is the Power River Basin.
		• CBM wells:
		  ○ Some CBM wells are vertical.
		  ○ Some are cased through the coal seam(s).
		  ○ Some are completed open hole.
		  ○ Some CBM wells are directionally drilled.
		  ○ Some use a twin well concept similar to SAGD.
		• CBM development:
		  ○ The CBM wells need to be dewatered to allow the gas to desorb from the coal.
		  ○ Initially this was done with water well ESP’s.
		  ○ Then special CBM ESP’s were developed.
		  ○ Today, some oil well ESP’s are used.
		  ○ Some wells are also produced by PCP and by Beam Pump.
		  ○ The next step will be to develop a more robust ESP.
		• Failures:
		  ○ 33% of failures are due to pump problems.
		  ○ 25% of failures are attributed to design problems.
		• Issues:
		  ○ Pumping coal bed fines.
		  ○ Handling the gas by using separators, shrouds, VSD’s.
		  ○ In 1995, used Turpin relationship to define the “stable” operating area.
		  ○ In 1990’s, developed NPSH stages and re-circulation systems to cool the motor.
		  ○ There are special CBM cables.
		  ○ There is a “Gas Pro” system that can inject produced water downhole, like the DHOWS system for oil wells.
		  ○ More CBM wells are being directionally drilled.
		  ○ This leads to slugging problems with the horizontal legs.
		  ○ Approaches to address this include the inverted shroud, inverted shroud in a sump, and an inverted shroud with a re-circulation system.

Paper	Author(s)	Summary of Discussion

		• Future:
		  ○ Drill special configurations with one large wellbore for dewatering and several offset wells to produce gas.
		
		Q. How many configurations are actually used?
		A. Most of the ones discussed in this paper have been used. Many in West Virginia.
		
		Q. How can the dewatering phase be shortened?
		A. If the wells are pumped too hard, this increases the production of fines and shortens the pump run life. So we can't get too aggressive. Some Operators rotate their pumps to more than one well.
		
		Q. What is the breakeven point for use of VSD's?
		A. Some people use small, inexpensive VSD's.
		
		Q. Do people use pump-off control?
		A. Several methods of POC have been tried.
		  • There has been some success based on motor control, but this is costly.
		  • It is hard to justify use of downhole sensors.
		  • Total well cost is usually less than $200,000.

Reliable Low Flowrate Centrifugal ESP's for Oil Production in Severe Conditions	S. Ageev
	Special Design Bureau "Connas"
	
	P. Kuprin,
	V. Maslov,
	M. Melnikov,
	O. Perelman,
	S. Pescherenko and
	A. Rabinovitch
	JSC Novomet-Perm
		This is a story about development of reliable low flow rate ESP's in Russia.
		
		• Target:
		  ○ Develop 362 and 400 series ESP's
		  ○ Target 32 – 160 M^3/Day.
		  ○ Warranty 1000 days.
		  ○ Be able to produce more than 500 mg/liter of solids.
		• Approach:
		  ○ Develop a new stage design.
		  ○ Use centrifugal + vortex impellers in each stage.
		  ○ Use powder metallurgy.
		  ○ The vortex "row" of impellers is used to increase the head.
		  ○ The performance is 15 – 28% better than the old design.
		  ○ Forces are reduced on the impellers.
		  ○ This improves gas handling.
		• Manufacturing:
		  ○ The normal method is with casting.
		  ○ This uses a new patented manufacturing technique.
		  ○ It produces low surface roughness, better balance, less vibration.
		  ○ It is an optimum design to handle solids.
		  ○ It has better tolerances.

Paper	Author(s)	Summary of Discussion
		○ It uses wear resistant bearings. ○ It has reduced radial movement. ○ Its durability is improved by more than 10 times. ○ Its life is warranted for more than 1000 run days. • Software for selection: ○ Models the unit in 3D. ○ Shows impact on installation if pump is not installed in a straight part of the hole. ○ Eliminating bends reduces pump failures. ○ The software also calculates heating. ○ It can be used to select a tapered pump. • Results: ○ The new pumps are lasting more than 1000 days. ○ Currently more than 1600 of these new pumps are in use in Western Siberia and a few other places. Q. What material is used for the bearings? A. Carbide. Q. Have you tried magnetic bearings? A. Not yet. Q. Can powdered metallurgy be used in corrosive fluids? A. Yes. In TNK/BP we use 316 LSS. Q. Can you use powdered metallurgy with "ni-resist" stages? A. No answer. Q. Are these pumps installed outside of Russia? A. Yes, they are also installed in some CIS countries. Q. Are you considering offering these pumps in other parts of the world? A. No answer. Q. What size sand did you use in your testing? A. 17 microns. Q. How do you measure the amount of sand and the size of the sand in the production? A. Some of the wells produce a lot of sand. The sand particles cover a wide range of sizes. We have seen very little wear after the pumps have been used in this service.
Artificial Lift Innovations in Eastern Venezuela	C. Brunings, J. St. Bernard, and P. Vasquez PDVSA	This is a story about ESP innovations in Eastern Venezuela to handle gas and improve power usage. • "Viper" pump vanes: ○ The pump uses 562 series "viper" stages.

<table>
<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
<tr><td colspan="3"></td></tr>
<tr><td></td><td>A. Yamhure,
J. L Salazar, and
K. Marcano
Baker Hughes Centrilift</td><td>

The production is highly viscous.
The fluid flow pattern is stratified – low differential pressure.
Production rate is 750 – 1500 B/D.
Depth is 3000 – 3150 feet.
The design was checked with a simulation using the “Autograph” program.

Field test:
Using the “viper” vanes increased production.
Power consumption at lower production rates was reduced by 15 – 29%.
The cost was less to install smaller equipment.

Pump design:
This is a multi-tapered pump.
It uses a single housing with multiple tapers.
It can have up to three types of stages in one housing.
Like with gas compression stages, it handles some free gas.
It is referred to as a “Super Merey” pump.

Field test:
The pump experienced no gas locking in over one year of use.
The amp chart was smooth.
Production increase was 46%.

Q. Have tests been conducted in the field?
A. We plan to test this in the field when an existing pump fails.

Q. Is the tapered pump controlled by amps or frequency?
A. It is frequency controlled.

Q. Are there vibration problems with the tapered pump?
A. The special stages eliminate vibration.

Q. What is the temperature in the heavy oil production
A. It is on the order of 230 ^{o}F. We haven’t had a temperature problem.
</td></tr>
<tr><td>Short Story: Development and Field Trials of a High Volume High Torque ESP-PCP</td><td>J. English
ChevronTexaco

D. Watts
ConocoPhillips</td><td>This is a story about the development of a high volume, high torque ES-PCP unit in Ameriven, PDVSA, in the Orinoco Basin in Eastern Venezuela.

The wells:
The wells are drilled from pads, with 14 wells per pad.
They are extended reach, horizontal wells.
Multiphase pumps are used to boost the production to the production facilities.

</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		○ There are 240 wells. 187 are on production. ○ Field production is 190 – 200,000 BOPD. ○ All wells use VSD's. ○ All are on a SCADA system. ○ Well depths are 2400 – 3000 feet. ○ Rod-driven PCP pumps are used. ○ Typical production rates are 1750 – 4400 B/D. ○ The wells have 5.5" tubing and use 1.5" rods. ○ The PCP's are single lobe and turn at 350 RPM. ○ The torque is 2400 ft-lbs. ○ To reduce torque, some diluent is injected. • Consider moving to ES-PCP. ○ Can obtain higher torque. ○ Have more flow area in the tubing (since some is not required for the rods). ○ No stuffing box is needed. ○ There are no problems with the well deviations. ○ The motor temperature helps to reduce the fluid viscosity. ○ But, CAPEX is higher. • Initial trials: ○ The initial trials were not OK due to improper design. ○ Needed a high torque PCP. ○ There were other issues that have been solved. ○ To date, 4 units have been built. ○ Three of these have been modeled. ○ The total length of the assembly is 83.5 feet. • Initial results: ○ All of the new units are operating. ○ All have reasonable torque requirements. ○ They can be installed deeper since rods aren't required to drive them. ○ There have been no failures so far. • Future plans: ○ Continue to improve the reliability. ○ Install new units even deeper. ○ Plan more use of ES-PCP concept. ○ Plan to use new installation methods where the PCP can be changed but keep the same motor. Q. What are the benefits of ES-PCP vs. PCP? A. Less rod wear, less torque, greater flow area. Q. What is your experience with the gearbox? A. Torque is 3600 ft-lbs. Power is 228 HP and 171 HP, in different units. Q. Is the motor 4 pole? A. Don't know. Q. At what RPM are you operating?

Paper	Author(s)	Summary of Discussion
		A. 200 – 350 RPM. This is the same as with the surface drive units Q. What is your casing size? A. 9-5/8”.
Steam Assisted Gravity Drainage with Electric Submersible Pumping Systems	R. Bowman and D. Rowatt **Schlumberger** S. Solanki and B. Karpuk **Encana Oil and Gas Partnership**	This is a story about production from SAGD (steam assisted gravity drainage) wells in Northern Alberta, Canada. • Background o Conventional oil production is declining in Canada. o Production from SAGD wells is increasing. • The SAGD process: o Two parallel, horizontal wells are drilled. o Steam is injected in the upper well, which is approximately 5 meters above the lower, producing wellbore. o The injected steam rises in the formation and heats the oil and it flows down to the producing wellbore by gravity drainage. • Production methods: o Formerly, gas-lift was used to produce the SAGD wells. o It required high power (for compression) and there were problems with instability due to the horizontal wellbores. o Now ESP’s are used. o Production is controlled. o The produced emulsion is produced to the treating plant. o By using the ESP, the pump intake pressure, and thus the flowing bottom-hole pressure can be reduced. o The lower reservoir pressure helps to optimize the steam coverage and use in the reservoir. • The ESP’s. o Use a “Hotline” 550 SAGD pump. o It is rated for 218 ^{o}C (425 ^{o}F). o Production rate is 300 – 1000 M^3/Day, or 1900 – 6300 B/D. o The pumps are landed in the horizontal portion of the wellbore. o They experience a rapid temperature increase. o The temperature at the surface is very low. o The wells produce approximately 1% sand. o A VSD is used. o The minimum MTBF is greater than one year. • Challenges: o High temperature in the reservoir. o Sand. o Temperature cycles. o Setting the pump in the horizontal wellbore. • Pump system design:

Paper	Author(s)	Summary of Discussion
		○ Advanced insulation. ○ All steel stators. ○ ARZ bearings. ○ High temperature di-electric motor cooling oil. ○ Elastomers able to withstand up to 550 °F. ○ High temperature pothole. ○ Seal sections: normal bags fail, so use all metal bellows. ○ The protector (seal section) has been redesigned to better handle sand. ○ Cable is able to withstand up to 500 °F. • The ESP pump design: ○ Must account for "thermal growth" issues. ○ Must handle solids. ○ Must be able to function in the horizontal orientation. ○ Keep the pump intake on the bottom of the casing, to assist with ingestion of more liquid, less gas. • Acceptance test: ○ The new units were run for 100 hours in a hot loop. ○ They were subjected to thermal cycles. ○ A 75 °F safety factor was applied. • Results: ○ The new units have been installed in three fields. ○ Depths range from 475 –780 meters. ○ Oil gravity ranges from 9 – 10 °API. ○ The wells produce 60 – 70% water. ○ Total production rate is 300 – 900 M^3/Day. ○ Temperature is about 205 °C. ○ The operating bottom-hole pressure is very low. ○ This leads to a low steam/oil ratio (SOR). ○ The first "hotline" pump ran 630 days. ○ So far, there are 16 SAGD wells using the new SAGD ESP. ○ Run time is greater than one year. Q. Do you use downhole sensors? A. No. These are currently only rated to 125 – 150 °C. We use a "bubble tube" to measure the pump intake pressure. Q. Why use ESP and not hydraulic pumps? A. ESP's are more operationally friendly. They don't require injection of power fluid. Q. What series bellows are you using? A. We run a 540 protector. We run a single seal with multiple bellows sections. Q. How much sand are you producing? A. We produce a little sand (approximately ½%) dur-

Paper	Author(s)	Summary of Discussion
		ing clean-up. Long term we don't produce sand. If a well starts to produce sand, it is stopped and the sand control is repaired. Q. How low is the flowing bottom-hole pressure? A. We normally operate with a pump intake pressure of about 700 – 800 kPa (100 – 115 psi). Q. What are your surface facilities? A. The facilities on the pad are simple. The production is pumped by the ESP to the treating facilities. Q. What is the size of the flowline to the facility? A. There is not a standard. This is based on experience. Q. What are the advantages of ESP vs. use of sucker rod lift? A. Ability to work in horizontal portion of well. No problems with rod drag in well doglegs. Rod pump range is too low. Q. Do you have problems with gas separation and handling? A. There are some gas handling problems? Q. What is your GOR? A. It runs about 4 – 20 M^3/M^3. Q. What temperature rise to you see in your motor? A. We limit the motor temperature to 550 °F. We see a 120 °F motor temperature rise.
Closing Comments		
Closing Comments	Shauna Noonan, ConocoPhillips, General Chair of the Workshop	Malcolm Rainwater of WoodGroup ESP made the closing remarks on behalf of Shauna Noonan. • He thanked all of the presenters and participants. • He invited all attendees to return for the 2007 ESP Workshop. • It will be held at the same time of year, and in the same location at the Woodlands Waterway Marriott Hotel.

Wednesday

01	02	03	04	05	06	07	08	09	10	11	12	13

Thursday

14	15	16	17	18	19	20	21	22	23	24	25	26	27

Friday

28	29	30	31	32	33