2013 27th ESP Workshop

Summary of Presentations

Woodlands Waterway Marriott Hotel

Wednesday, April 24 – Friday, April 26, 2013

Prepared by
Cleon Dunham, Oilfield Automation Consulting, Artificial Lift R&D Council
May, 2013

Paper	Author(s)	Summary of Discussion
	Purpose of this Document	
Purpose of this Document	**Cleon Dunham** **Oilfield Automation Consulting, Artificial Lift R&D Council**	The purpose of this document is to summarize the main points of the technical presentations at the 2013 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 39 pages of notes. If anything is presented incorrectly I may not have heard or recorded it correctly, so the fault is mine, not the authors and/or presenters of the papers. The lead authors (or the authors who presented the paper) are shown in bold color with each paper. The authors are welcome to correct the summaries if needed. Attendance at this year's workshop: 557 signed up in advance. There were 630 attendees in all – a new record • This is the 27th ESP Workshop. • The first one had 60 people. • 557 people signed up in advance to attend this year. There were 630 attendees in all – a new record. • The attendees came from 26 separate countries. • They represented 90 different organizations.
	Opening Comments **Workshop Co-Chairs:** **John Patterson – ConocoPhillips** **Jeff Dwiggins – Dwiggins Consulting**	
Opening Com-	**John Patter-**	**John Patterson**, the 2013 ESP Workshop Chair, welcomed all attendees.

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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
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<tr><td>ments</td><td>son, ConocoPhillips
Jeff Dwiggins, Dwiggins Consulting</td><td>

He asked a representative of the Marriott Hotel to give a safety briefing.
He announced that on Monday and Tuesday, there were four Continuing Education classes. ESP 101, ESP 102, VSD, Seven Secrets to Good ESP Operation
On Wednesday – Friday, there will be Technical Presentations, Breakout Sessions, and Exhibits in the Exhibit Hall.
He recognized the contributions of Mr. Carl Cox who passed away in Feb. 2013. Carl was a strong leader in the ESP industry. He was one of the early developers of Failure Analysis and ESP Quality Programs. His wife and children were present to hear him being honored.
He introduced the Keynote Speaker, Mr. Mike Mason of Apache Oil Company.

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<tr><td colspan="3">Keynote Address</td></tr>
<tr><td>Keynote Address</td><td>Mike Mason
Apache</td><td>
Mr. Mike Mason of Apache gave the Keynote Address. He is CTO or Apache.

Who Cares about ESP's?

Market Analysts – ESP performance affects financial results.
CEO's. The affect the operating bottom line.
There are 130,000 ESP's operating globally.
60% of world oil is produced by ESP's.
Total world oil production is 89 MMBOPD.

What is the Power of 1%?

This is 534,000 BOPD or $53 MM$ per day.
US production is up.
US imports are down.

New World Order.

He showed a movie of an automatic driving car being used by a blind person. This technology is coming.
He discussed the X Price process.
The internet will be worth $15 trillion by 2030.
A 1% increase will be worth $60 billon.
Today 99% of items in the world are not connected to the internet.
The network impact:

Machine to machine.
Machine to people.
People to people – social networks.
Services will double in 4 years.
Today 3 MM e-mails are sent per second.

Apache's Journey:

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– 800,000 BOPD.
– 50% of production is oil, 50% is gas.
– 50% is in North America.
– Run 500 ESP's in the Permian Basin.
– Run 500 ESP's in the Middle East.
– 35% of production is by ESP.
– Sensors play a big role in operation of ESP's.
– ESP data:
▪ Volume, velocity, veracity.
▪ Down hole measurements.
▪ More reliable ESP's.
▪ Problem analysis and diagnosis.
▪ Surveillance, prescriptive analysis.
▪ Better predictions.
– Collaboration
▪ Data, text, models, image processing
– Future
▪ Better run life estimates.
• Q. Is Apache working on specific sensors?
– A. Not yet. Plan to address in 2014.
• Q. 35% of Apache production by ESP. Is this increasing?
– A. It will increase because the CEO wants it to.
• Q. Is software being developed by Apache?
– A. No. We work with a 3rd party in Austin.
• Q. Do you develop your own sensors?
– A. Some, but mostly work with sensor providers.
• Q. What is the biggest gap in monitoring ESP's?
– A. Learning from teardowns.
• Q. Do you pre-pull ESP's to fix before they fail?
– A. Yes, sometimes.
• Q. What is your ESP "Center of Excellence?
– A We monitor ESP health worldwide.
• Q. Are life estimated based on real data or industry data?
– A. We are working to build in more field data.
• Q. What are you doing with multi-frac wells?
– A. We need to learn more about producing long horizontal wells. We need to better understand toe up vs. toe down.
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<tr><td colspan="3">Session I
ESP Operations
Session Co-Chairs:
John Patterson, ConocoPhillips
Jeff Dwiggins, Dwiggins Consulting</td></tr>
<tr><td>ESP Installation Strategy, Well Delivery Efficiency without Compromising</td><td>Euan Alexander, Apache North Sea Ltd.</td><td>
This is about operations in the Forties Field in the North Sea.
• Goal is to maximize recovery and increase run life.
– 180 ESP's.
– 5 Platforms.
• Determine reservoir target.
– Conduct 4D seismic.
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Paper	Author(s)	Summary of Discussion
ESP Run Lift in the Forties Field, UKCS	Paul L. Nicoll, Apache North Sea Ltd.	– Evaluate well performance. – Address well hazards – clay, shale, sand. • Site preparation: – Use plug and cage type. – Design the Christmas Tree for ESP use. – Monitor A, B, and C annuli – Use chemical injection to inhibit scale, corrosion. – Monitor with DCS, tied to SCADA system. – Monitor and control from control room. – Use VSD's on every well. – Provide quality power on the platforms. • Drilling: – Drill a flat tangent: 45 M for single ESP's, 150 M for dual ESP's. – Keep dog leg severity less than 5%. – Use 9-5/8" and 7" casing. L80, chrome. • Completion: – Sand control – gravel pack and cased hole frac packs. – 15 chrome, L880 tubing. • ESPs – Schlumberger – Guarantee 2 year run life. – Range of pump sizes. – Range of motor sizes. • Conclusions – Interactive contract. – Review drawings. – Contract monitoring. – Best estimates of well performance. • Q. How decide on single vs. dual completions? – A. Have a plan and use pilot holes. • Q. Does 5^0 deviation per 100 feet depend on casing size? – A. No. • Q. How much sand is produced? How address this problem? – A. We stop sand production. We keep the ESPs on line. • Q. What is the operational philosophy with dual ESPs? – A. Same as for singles. Use auto. "Y: tools. Change to the 2nd ESP when the 1st ESP fails. Operate the bottom ESP first. • Q. What is the most common failure? – A. Electrical failures in the motor. • Q. Why change motor windings? – A. To minimize motor failures. • Q. What is your pre-installation process? – A. Analyze performance. Review with Schlumberger. Go over a check list: sand, rates, etc.
Artificial Lift ESP Solutions for the Unconventional	**H. C. Kip Ferguson III, Magnum**	This is a story about artificial lift solutions used in the Eagle Ford Shale formation. • Producing in the oil region of the Eagle Ford. • Wells flow for 5 - 8 months. Then use sucker rod pumping

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<tr><td>Plays in Eagle Ford Shale</td><td>Hunter Resources Corp
Kevin J. Robins, Magnum Hunter Resources Corp. Diego A. Narvaez, Schlumberger</td><td>or gas-lift.
• Consider using ESPs for part of well’s life cycle.
• Have “toe up” horizontal configuration.
• Low water production results in poor cooling.
• Use Schlumberger ESPs and design process.
– Evaluate oil and pump conditions.
– Use OLGA to evaluate dynamic performance.
• The ESP system:
– Hardware
– SCADA and remote control.
– Continuous downhole data.
– Low production rates.
– Range of oil and gas production rates.
– High temperature: 270^o F.
– Manage drawdown to maximize recovery with ESP cycling.
– Shut down on high temperature or low pump intake pressure.
– Case History: 600 B/D to 75 B/D. Run 359 days. 1478 on/off cycles.
– ESP used to maximize performance. More effective than sucker rod pumping.
▪ Conclusions:
– Effective automation with ESPs.
– Good downhole data.
– Use sucker rod pumping to evaluate reservoir performance.
– Real-time SCADA is essential for monitoring performance.
• Q. Toe up vs. toe down?
– A. We use toe up for oil production, toe down for gas.
– A. Toe up is more efficient.
• Q. What is the cost of data collection?
– A. $5,000 - $15,000.
• Q. How do you control draw down?
– A. We use a target pump intake pressure of 1,400 psi.
• Q. Why does motor temperature fluctuate?
– A. We use a gas separator. Pump is installed in a vertical section of pipe.
• Q. Why don’t you pump in the horizontal?
– A. There is a lot of debris in the wells.</td></tr>
<tr><td>Case Study: Understanding and Improving ESP Reliability in SAGD Wells with High Dogleg Severity</td><td>John Greham, Sergey Belyaev, SPE
Alan Watt, Alejandro Camacho, SPE</td><td>This is a case study about improving ESP reliability in SAGD (steam augmented gravity drainage) operations.
• Suncor Operations
– 550,000 BOPD in total operations.
– Nine PADs in Tar Sands
– 10 – 20 wells per PAD.
– 126 wells total.
– 150,000 BOPD.
– SAGD wells.
– Schlumberger ESPs.
– Have some shaft failures.</td></tr>
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Paper	Author(s)	Summary of Discussion
		– ESPs are deployed in the horizontal. – ESP's are 60 feet long. – Wells have 17° per 100 foot bending. – We try to reduce dog leg severity to improve performance. – We use up to four stabilizers to strengthen the ESPs. – Most failures are due to high dog leg severity. – With stabilizers, shaft failures have been eliminated. • Q. How do you measure dog leg severity? – A. This is based on well geometry. • Q. How long are ESPs running now with less failures? – A. Much better since 2012. • Q. Are the stabilizers a standard product? – A. No. • Q. Is there a problem with setting the ESP above the bottom of the casing? – A. No. • Q. Are most failures on start-up or during normal operation? – A. Most failures are in normal operation, not on start-up. • Q. Are you evaluating start-up operations? – A. We evaluate only during normal operations.
ESP Well Surveillance Using Pattern Recognition Analysis - PDO	**Addullah Awaid, Khalfan Al-Harthy, Petroleum Development Oman** Harith Al-Mugbali, Atika Al Bimani, Zeyana Al-Yazeedi, Humood Al-Sukaity, PDO Alastair Bailliie, Engineering Insights, Ltd.	This is a story about well surveillance in Oman. • In Oman: – 34% of production is operated by Petroleum Development Oman (Shell). – 126 Fields. – 4,010 wells on artificial lift. 24% operated by ESPs. – 60 – 90% water cut. – North Oman: Carbonate reservoirs, 1,200 – 3,600 meters deep. – South Oman: Sandstone reservoirs. – Surveillance by downhole monitoring, SCADA systems. Use PI and LOWIS. – Use Pattern Recognition Analysis. o Respond quickly to failures. o Have quick recovery from failures. – Working to develop a Failure Prediction Tool. o ID failure patterns. o ID types of failures. – Analysis performed: o Use pressure profile from wellhead pressure to pump discharge pressure. o Calculate delta P across the pump to determine pump intake pressure. o Use pressure profile from PIP to FBHP. o Determine IPR. – Determine type of failure. o Pump intake blockage. o Increase in reservoir pressure. o Broken pump shaft. o Hole in tubing. – Approach.

Paper	Author(s)	Summary of Discussion
		○ Integrate with trending tool. ○ Use NODAL Analysis – Conclusions: ○ Can use this tool to improve pump performances. ○ Can integrate the Failure Prediction Tool with LOWIS. • Q. Why are you getting tubing failures? – A. We have high water cuts, production of fines, high salinity, and corrosion. • Q. Can you sue Pattern Recognition on gassy wells? Is this better than simple NODAL Analysis? – A. We are targeting repetitive failure. We don't use NODAL Analysis on all wells. • Q. Do you have problems with gas locking? – A. We will look into it. • How successful is manual pattern recognition? – A. We have dedicated staff and help from the ESP Vendors. • Q. How long have you been using Pattern Recognition: – A. Two years. • Q. What do you do if you don't know the type of failure? – A. We run field tests, we develop a history, and we use the expertise of the Service Companies.
Benefits of Pump Friendly Wellbore Design in Directional Drilling and Completions	**Leslie C. Reid, Baker Hughes, Inc.**	ESPs are being used in unconventional plays. • Why is it important to have an ESP friendly well design? – Want to use ESP's when there is lots of liquid to be produced. – Gas can be a problem. – Need to avoid use of banding. – Need to avoid close tolerances. – Toe up wellbore designs can prevent gas slugging. – Can use a sump to avoid gas in the pump. – Be gentle with dog leg deviations of less than 6^{o} per 100 feet. Certainly stay below 10^{o} per 100 feet. – Set the ESP in straight pipe, less than 2^{o} per 100 feet. – Be flexible and willing to change. Try to set ESPs in large casing. – Determine how much straight hole is needed. This depends on the size of the ESP. – Consider length of sumps. – Evaluate the cost of a slant vs. a vertical sump. – Must have good communication between the Operator and the Service Company. • Q. Can you extend the sump to the end of the horizontal section? – A. This is an option. • Q. Does the size of the tubing change the pump design? – A. It needs to be considered. • Q. What hole deviation is really needed? – A. Sometimes 5^{0} per 100 feet is OK; but this depends. • Q. What is the required distance between the bottom of the tube and the sump?

Paper	Author(s)	Summary of Discussion
		– A. Draw down depends on where the sump starts. But sumps are doable. • Q. What is the relationship between dog leg severity and run life? – A. There are big gains if dog leg severity can be limited.
Session II **Equipment and Hardware – Understanding the Limits** **Session Co-Chairs** **Keith Fangmeier, Hess Corporation** **William Milne, Centrilift**		
Development of Advanced Electrical Submersible Pumps to Meet Today's Challenges	**Geir Heggum, Statoil ASA** Cyril Girard, Statoil ASA William Harden, Steven McNair, Scott McAllister, Clyde Union Pumps, an SPX Brand	This is about the next great ESPs to be used in Norway and the Gulf of Mexico. • Norway: – 500 subsea wells. – 1,000 platform wells. – Need a retrofit solution. – Current lift methods are not good enough. – Need smart ESPs, higher rates. – Need longer run lives. • Challenges: – Deep water. – Harsh climate. – Need longer run life. – High CAPEX, High OPEX, High Water Cuts – Current ESP run lives are relatively small. – Need a step change in design. – Need to consider entire system thinking. • Goals: – Eliminate need for thrust bearings. – Eliminate shaft seals. – Enable high speed operation. – Increase pump speed, reduce number of stages. – Go from 3,600 RPM to 8,000 RPM. – Significantly reduce number of stages, reduce pump length. • Business case: – ESP run life equal to well life. • Q. How close are you to meeting these goals? – A. Having a permanent magnet motor is difficult. Will need "clean" fluid. • Q. Losses are proportional to speed^3. How get high speed? – A. We don't know yet. • Q. Life expectancy is based on literature. – A. This is currently under study. • Q. What is your target ESP run life? – A. We want five years, or more. • Q. How will you handle trust? – A. We aim to eliminate drive shaft thrust.

Paper	Author(s)	Summary of Discussion
		• Q. Why not work with a larger ESP Supply Company? – A. We conducted a screen study to choose the company we will work with. • Q. Why use a high horsepower pump? – A. This wasn't answered.
ESP Seal Chamber Section (SCS) Performance Testing	**Francisco Tervisan, C-FER Technologies** Brandon Curkan, C-FER Jeff Dwiggins, Dwiggins Consulting LLC Chris Benoit, Schlumberger John Patterson, ConocoPhillips	• Introduction: – Limited seal section testing. – ConocoPhillips worked with C-FER to test seal sections. – Tested Schlumberger seal sections. – Instrumented to measure performance during the tests. – Measured P, T, Diff. Pressure, Q. – Simulated downhole conditions. – Simulated installation, start-up, operation, and shut-down. • Results: – Had several shaft failures at 40 psi. – Seals performed as expected. – There were some unexpected results. – There are preliminary results. • Q. Do you plan to cooperate with different Manufactures? – A. Yes. • Q. Have your test goals changed? – A. This depends on the questions raised by ConocoPhillips. • Q. Could you use infrared monitoring? – A. This might be possible. • Q. At what temperature did the relief valves open? – A. 120 ^{o}C. • Q. What was the temperature rating? – A. 150 ^{o}C. • Q. Why did you use differential pressure and not absolute pressure? – A. This provided better resolution of about 0.1%. • Q. What was the rating of the trust bearing? – A. Don't know, but it was relative to the trust bearing load.
Rotor Dynamic Characterization of an Electrical	**Robert Marventh, GE Oil and Gas Arti-**	• Project motivation: – Increase run life. – Increase bottom-hole temperate limits. – Use subsea.

Paper	Author(s)	Summary of Discussion

Submersible Pump Motor	**ficial Lift, Ken Salas, GE Global Research** Adolfo Delgado, Jeremy van Dam, GE Global Research Stephen Sa-kamoto, GE Oil and Gas Artificial Lift	– Use in SAGD.
		– Use in mining operations.
		• Overall goals:
		  – Determine the factors that affect roto-dynamics.
		  – Determine the electro-magnetic excitation.
		  – Reduce vibration.
		• The tests:
		  – Monitor shaft displacement at the rotor bearings.
		  – Monitor housing vibration.
		  – Monitor motor skin temperature.
		• Test results:
		  – At the cylinder sleeve.
		  – Create a 3D plot of frequency vs. speed.
		  – Vibration was relatively insensitive to horizontal vs. vertical orientation.
		• Findings:
		  – Reduce vibration to improve reliability of motor bearings.
		  – Works in both horizontal and vertical orientations.
		• Q. Have you correlated vibration and run life?
		  – A. No.
		• Q. Is this bearing now commercial?
		  – A. Not yet.
		• Q. Can you see the effects of instability in the tear down?
		  – A. The rotor bearing shows wear.
		• Q. Are you using steel or ceramic bearings?
		  – A. This is proprietary.
		• Q. Is there a correlation between temperature and your results?
		  – A. As T increases, viscosity decreases. Saw no effect on the overall results.
		• Q. Electric magnetic flux; how is this affected by motor oil?
		  – A. Flux plays a smaller role with the new design.

Designing a Surface Horizontal ESP to Operate at 10,000 PSI for Lower Tertiary Miocene Sand Water Flood in the Gulf of Mexico	**William D. Bolin, Anadarko Petroleum Corp.**	This is about using ESPs to provide water for a water flood.
		• The water flood started in the early 1960's.
		  – It was increased after 1973.
		  – Arco uses ESPs for the water flood.
		  – Early on there were problems.
		  – Pressure control was added to address some of these.
		  – The initial pressure limit was 5,000 psi.
		  – It was then beaned up to 8,500 psi,, 600 RPM.
		  – The target is to inject 10,000 B/D using two pumps in series.
		  – To do this, need a special seal; they don't have a 5,000 psi seal.
		  – They inject sea water; need to remove the oxygen.
		  – Need special bearings.
		  – Want to use a new pump to increase injection to 14,000 B/D.
		  – Will use twin 2,500 HP motors; use a VSD.
		  – It is the highest pressure water flood in the world.
		• Q. What are the specs. used for the motor?
		  – A. Use a special junction box.

Paper	Author(s)	Summary of Discussion
		– Pump the well up slowly. – Use initially on one pilot well. • Q. Do you need special lubrication? – A. No. We use standard seals, with oil. • Q. Do you need special bearings? – A. No. These are available. • Q. What instrumentation is needed? – A. Use an RTD and a vibration sensor. – The goal is to fix it before it breaks. – Measure pressure. – Use a PLC and a shared VSD. • Q. Why are the pumps in series, and not parallel. – A. We need them in series to get to 10,000 psi.
Reducing Production Costs with Permanent Magnet Motor Electrical Submersible Pumps	**Trevor Kopecky, Borets Weatherford** Jeff Dwiggins, Apache Corp. Dwiggins Consulting Ryan Hughes, Borets Weatherford	This is about using a permanent magnet motor. • Motor: – Three phase motor. – Use close speed control. – Has a low heat rise; cooler running, – A permanent magnet motor (PMM) is more efficient for ESPs. • Case study: – Evaluate power efficiency vs. induction motor with a VSD. – Used a “vanilla” well for the first test. – Ran a test to compare the two types of motors. – Used a SCADA system to collect test data. – The PMM installed in Sept. 2011. – The pump was pulled after the test. – Instilled again in Oct. 2011. – The PMM used 20.8% lower power. – This saved $ 3,000 per month. – The PMM efficiency was better than the induction motor. • Apache: – New installs will use PMMs. – There are seven new installs. – They have 165 days run time. – They can use shorter units; can work in larger dog legs. • Q. What control system did you use? – A. We had to change the control system to one provided by Borets. • Q. Why is the PMM better at high production rates? – A. We need to run in more wells with new pumps to determine the overall benefits. • Q. What break horsepower is needed? – A.240 break horsepower. • Q. Does the savings justify the extra cost of the PMM? – A. It increases the horsepower but we get power savings. • Q. What was the Hertz for the test? – A. We ram at 120 Hz.

Paper	Author(s)	Summary of Discussion
Improving ESP Performance to the Next Level: Practical Guidelines	**Byran Richards, Submersible Pump Standards Ltd. UK** Atika Al-Bimani, Petroleum Development Oman Alastair Baillie, Engineering Insights, Ltd.	This is a talk about improving ESP performance in Petroleum Development Oman. • Goals: – Increase run life. – Reduce OPEX. – Reduce ESP failures. Have had 200 ESP failures per year. – ESPs are the highest lifting costs in PDO. – Run life is improving, but only in the last 2 – 3 years. Want to improve it more. • Approach: – Using consultants. – Focusing on people. – Improving training; using patter recognition. – Performing root cause analysis. – Seek a target run life of 5+ years. – People problems; lack of focus, lack of training. – Increasing training to address problems. – Improving maintenance. – Implementing a Quality Management System (QMS). o Following ISO 9000. o Using 8 principles. – Conducting internal and external audits. – Adopting the QMS. – Improving communications among all staff. – Going for a 5+ year run life. • Q. Who performs the field services? – A. This is mostly done by PDO staff, with some by the Service Companies.
Alternate No. 1, HPHPS Used to Support Shale Gas Fracturing in Horn River	Dana Pettigrew, Nexen Inc. Wojciech Andy Limanowka, Canadian Advanced ESP, Inc.	This Alternate Paper was presented on Thursday afternoon.
Alternate No. 2, Power Saving in ESP Production	Evgenii Poshvin, Novomet Group of Companies	This Alternate Paper was not presented.
Breakout Sessions **#1 – ESP Cradle to Grave – Chair: Leon Waldner** **#2 – How Does Arc Flash Affect Operational Safety? – Chair: Bill Bolin**		
ESP Cradle to Grave	**Chair: Leon Waldner**	Leon Waldner of Nexen presented an overview of the ESP life cycle from cradle to grave. • Cycle components: – Artificial Lift selection. – Collect well data. – Perform application design. – Evaluate information. – Review project economics. – Consider contract strategy.

Paper	Author(s)	Summary of Discussion
		– Safety. – Well and artificial lift system operation. – Perform reliability analysis. – Deal with disposal of the used equipment at the end of the project.
Session III **Hot, Hot, Hot, and Hot** **Session Co-Chairs** **Ralph Harding, Chevron** **Nichole Jabsen, ExxonMobil**		
Got Steam – Understanding ESP Steam Handling Capabilities in the Centrifugal Pump	**Shauna Noonan, ConocoPhillips** **Aaron Baugh, C-FER Technologies** Wayne Klaczek, C-FER Technologies Kelvin Wonitoy, Lyle Wilson, John Bearden, Baker Hughes	This is about the SAGD operations in Canada. • Conditions: – Temperature is 250 ^{o}C. – Want to determine how well ESPs perform. – Run tests in the CFER lab to determine ESP performance. • Develop a test loop to test high temperature ESPs. – Measure internal temperature at 25 locations. – Controlled many variables. – Prepared videos to show: ○ 125 ^{o}C. ○ 125 ^{o}C with air injection. ○ Increased pressure. • Conclusions: – With steam, the top of the pump is hotter. – Want to shorten the pump. – Gas causes steam to flash easier.. • Way forward: – Conduct more testing. – Develop a software program to evaluate effects of steam. • Q. What pressure is needed to inject air? – A. Haven't studied yet. • Q. If you test with water and air, would this change the pressure? – A. Probably. • Q. How is the performance per stage evaluated? – A. Control the discharge pressure to be close to the operating pressure. Determine the pressure changes through the pump. • Q. Did the flow rate change during the test? – A. The flow rate dropped when air was injected. • Q. Can you extrapolate to different gas volume fractions. – A. No. This depends on the slug geometry.
A Case Study on ESP Gas Locking Ride	**Zsolt Vigh, Nexen, Inc.** Michael Dowling,	This is another story on SAGD operations. • Well geometry; – There is 5 meters between the upper and lower horizon-

Paper	Author(s)	Summary of Discussion

Through in SAGD	Schlumberger, Lean Waldner, Nexen, Inc.	tal well.
		– An ESP is installed at the heel of the well.
		– ESPs are the most used form of artificial lift in these wells.
		– The "cold" viscosity is 1,000,000 centipoise.
		– The "heated" viscosity is less than10 centipoise.
		– There are some problems with gas locking.
		– Can slow the ESP to break the gas locks.
		– Some wells gas lock with no leading indications.
		  o Tests have been conducted to understand why.
		  o A well with a gas handler locked after 15 minutes.
		  o In some cases, had to stop the pump to overcome the gas lock.
		  o When the wells were restarted, it started to produce OK again.
		  o There is 95% success in doing this.
		  o When a well starts to gas lock, can slow the ESP to 35 Hz. to address the problem.
		• Q. Is this process automated, or controlled manually?
		– A. Is it manual, but we are looking at the possibility of automation.
		• Q. Are all wells experiencing the same water cut?
		– A. This was not considered.
		• Q. Does the gas handler help?
		– A. We didn't implement use of this across the field.

Thermal Perf Testing of High-Temperature E$SP Motor for SAGD	**Leon Wald-ner, Nexen, Inc.** Kelvin Wonitoy, Baker Hughes Wayne Klaczek, C-FER Technol-ogies Shauna Noonan, ConocoPhillips	This is another discussion of SAGD operations in Canada. • Conditions: – 250 °C. – High temperature of the motor is an issue. – Need to monitor ESP motor temperature. – Conducted tests to determine the temperature profile in the motor. • Tests conducted in the C-FER flow loop. – Tested at 260 °C. – Flow rate of 1,400 m^3/day. – Performed real-time measurements. – Needed to measure fluid properties. – Used a Baker Hughes (Centrilift) ESP. – Measured temperature internally and externally. – Measured temperature of fluid intake. • Objectives: – Evaluate the thermal design performance of the motor. • Results: – Had a motor temperature rise to 301 °C. – Evaluated temperature increments from 250 °C to 299 °C. – Determined the effect on the motor of these different temperatures. • Q. Did you see any wear after the tests? – A. No. Temperature rise may be more than 3 °C across the motor. More testing is needed. • Q. Did you evaluate the effect of temperature on the viscosi-

Paper	Author(s)	Summary of Discussion
		ty? – A. No. • Q. Could you see any radial displacement? – A. Would like to study this. • Q. Will the test results alter Nexen's control process? – A. This may change if we know more. • Q. Do you plan to test other motor models? – A. We would like to. • Q. Did temperature change during start-up, operation, and shutdown? – A. Yes, we saw some changes. The temperature increased when the motor was stopped. • C. Motors are being improved based on these tests? • Q. Did you test at the "O" flange? – A. No.
Expanding Horizons for High Temperature ESPs	**Song Shang, SPE, Schlumberger Canada, Ltc.** **Chris Scrupa, SPE** Claire Hong, SPE Lazar Velev, Cenovus Energy, Inc.	This is about Cenovus Energy SAGD operations in Canada. • Cenovus Operations: – Five fields in Canada. – Some fields are operated 50/50 with ConocoPhillips. – Produce up to 270,000 BOPD. – The fields are northeast of Edmonton, Alberta. – ESPs are used to produce the wells. – There is a gas cap above the steam zone. – Initially used gas-lift. – Now use Schlumberger ESPs. – Operate at 250 ^{o}C. – Have more than 170 ESPs in use. • Issues: – Initially using Generation II ESPs. – High temperatures. – Use double labyrinth chambers. – Were able to increase run life by 30%. • Using Generation III high temperature ESPs. – Includes a new seal section design. – Uses high quality motor oil. – Measure motor winding temperature. – Run life increased by 36%. • Conclusions: – With Generation III, can install ESPs without need for gas-lift. – We need to perform more studies. • Q. What is your MTTF? – A. Better than two years. –
High GOR Experience and Development concept for a Challenging Oil Field in the Sultanate	**Marcos De Berredo Petroleum Development Oman** Iqbal Sipra, Harith Al Muqba-	This is about dealing with high GOR production in Petroleum Development Oman. • Summary of operations: – Artificial lift method is based on achieving continuous performance. – 90% of PDO's wells are on artificial lift. – They are converting some wells from gas-lift to ESP. • Operations in Field "T"

<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>of PDO</td><td>li, Atika Al Bimani, G. H. Lanier, PDO</td><td>– This is a gas field.
– It has a clastic reservoir.
– The field is 49 kilometers from the nearest production station.
– A water flood is needed to recover the reserves.
• Artificial lift selection:
– Both gas-lift and ESP were considered.
– ESPs were chosen.
• ESP Assessment:
– High gas-liquid ratio.
– Must be able to handle free gas.
– Need 60% gas separation.
– There is field wide experience in handling gas in PDO.
– Initial production expected to be 300 M^3/Day.
• Production Philosophy:
– Need to export oil 49 kilometers.
– Need to have a tubing pressure of 35 bar.
• Completion Concept:
– Need a packer down to the base of the perforations.
• Conclusions:
– We needed to evaluate different artificial lift types.
– We will evaluate the use of ESPs in Phase I before we expand to Phase II.
• Q. How will you handle the gas?
– A. We will keep the reservoir pressure above the bubble point and bean back the wells as needed.
• Q. What is the GOR?
– A. We expect 216 M^3/M^3 at 300 M^3/Day oil production.
• Q. Why are you using a packer and no venting?
– A. We will operate above the bubble point?
• Q. What type of ESP are you using?
– A. The design of the ESP is based on the GLR. We plan on 5.3” OD pump with various numbers of stages.</td></tr>
<tr><td>Utilizing Gas-Lift Valve to Prevent ESP Gas Lock</td><td>Yue Guo, ConocoPhillips
Mauricio Oviedo, GE Oil and Gas Artificial Lift
Si Peng, ConocoPhillips
Bo Zhu, GE Oil and Gas Artificial Lift</td><td>This is about using a gas-lift valve to help prevent ESP gas locking.
• Concept:
– Using a gas separator.
– Gas is produced up the “A” annulus.
– Use a packer to protect the “B” annulus
– But we get some gas in the “B” annulus.
– We are using a gas-lift valve to let gas escape from the “A” annulus back into the tubing.
– The alternative of using a gas handler is too costly.
– We use a packer on the top of the “A” annulus and a gas-lift valve to get the gas back into the tubing.
– We use a standard gas-lift mandrel.
– We use in orifice-type gas-lift valve.
– When the annulus pressure increases, the gas flows through the orifice (which is always open) into the tubing.
• Q. Does the differential pressure keep the ESP operation stable?</td></tr>
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<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>– A. We only need about 5 – 8 psi differential pressure for gas to flow through the orifice valve.
• Q. Would it be possible to fix the well integrity problem?
– A. We “fix” by keeping gas out of the “B” annulus There is some gas leakage into the “B” annulus.
• Q. What is the GOR of the well and the loading on the ESP?
– A. We see the amps varying by 4 – 8 amps.
• Q. Did you consider an ejector?
– A. No. This works best with the orifice valve.
• Q. Is there back check on the orifice?
– A. Yes. We can retrieve the orifice by wire line if we need to do repair/replacement.
• Q. Is the differential pressure only the pressure across the orifice?
– A. There is some small pressure drop across the back check, but it is fully open during normal operation.</td></tr>
<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Session IV
Is It Still a System !!!!!!!!
Session Co-Chairs
Darryl Williams, Shell EP
Atika Al-Bimani, Petroleum Development Oman</td></tr>
<tr><td>ESP Rotor Bearing Failures & Fluting Phenomena</td><td>Cledwyn Hughes, Apache Corp.
Salvadore Grande, Magney Grande
Jeff Dwiggins, Apache Corp. (Dwiggins Consulting)
David Shipp, Eaton Corp.
Leslie Ord, Apache Corp.
Shaun Walsh, OMIS (Power Service) Ltd.</td><td>This presentation is a follow-up to one two years ago.
• Forties Field, North Sea.
– Five platforms plus one Satellite to Alpha Platform.
– Use many ESPs and some gas-lift.
– Produce 60,000 BOPD, 570,000 BFPD.
– Power is generated in the field.
– Size of the prize:
o 60% of wells produced by ESP; 60% of the oil production.
o 1 – 2 months between failures of ESPs.
o Want to improve run life.
o Goal is to improve run left to > 2 years,
o The longest run life is about 8 years.
o Avg. run life is 500 – 650 days.
– Review of tear downs.
o Perform root cause analysis.
o Sand is the biggest cause.
o Use sand control.
o Recently sand failures have decreased, electrical failures have increased.
o Having damage with rotor bearing fluting
– Using a VFD with pule width modulation (PWM).
o Problem in the 5hth harmonic.
o Using filtering to reduce the problem.
o Conducting a test program to evaluate the VFD and the quality of the power.
o If unfiltered, problem moves to 71st harmonic.
o Filtering cleaned up the problem.</td></tr>
</table>

Paper	Author(s)	Summary of Discussion
		– Conclusions: o Saw the fluting problem on the tear down analysis. o Installed filtering to solve the problem. – Future work: o Implement filtering where it is needed in the field. o Do more forensic analysis. • Q. Have you seen improvement in system performance from reducing motor Temperature? – A. This will be the next phase of the work. • Q. Has this happened with other motors? – A. Often the motors run too fast, so hard to see. There could be a problem with other motors. Most motors don't see the high frequency problems. • Q. Do you use non-conductive rotor bearings? – A. We will use these where it is pertinent. • Q. How do your motors without filters perform? – A. We haven't seen a problem. • Q. How many rotors on the motors? Is it worse at the bottom? – A. Yes. • Q. What did the base bushing look like? – A. It was OK. • Q. Would the rotor sand cut? – A. Probably. • Q. What is your operating frequency? – A. We operate at 2,400 Hz. If we go faster, the problem gets worse.
Advanced Signal Analysis of an ESP Failure Due to Scale	**A Y Bukhamseen, Saudi Aramco** M. N. Noui Meidi, Saudi Aramco	This is about a scale problem in Saudi Arabia. • Failure modes: – We have many failure modes. – 20% are due to burned motors. – Deposit of $CaSO_4$ scale is a problem. – Scale is worse with increased Pressure and Temperature. – We ran a CFD study to evaluate the problem. – Power fluctuations cause a problem. – Power fluctuations cause torque fluctuations. – We use a SCADA system to monitor ESP Temperature, Pressure, and Current. – We collect pertinent data. – We perform Fourier Transforms, Wavelet Transforms, and Dynamical Analysis. • Summary: – We use an ESP design based on performance feedback. – We use a tear down predictive tool. • Analysis: – Scale blocks fluid passage. – Signal analysis can be used to predict failures. • Q. Did scale back up in the rotor bearings? – A. Yes. • Q. Can you inhibit scale formation?

Paper	Author(s)	Summary of Discussion
		– A. We want to improve our scale inhibition program. • Q. Is the scale sourced from the formation? – A. Yes. • Q. Can you preform remedial actions to prevent failures? – A. Yes. We use a two-day back flush. • Q. Do you use this on a large number of wells? – A. Yes.
Evaluation of ESP Vibration: Technical Process versus Black Magic	**Michael Borsberg, Baker Hughes Centrilift**	• Recommendations: – Assure that tested equipment is fit for purpose. – There isn't much string test information available. – Most data is in torsional mode. – There is some roto-dynamic modeling. – API guidelines: 0.156 M/sec.; 0.1 In/sec. – Test equipment: o Follow API RP 11S8. o Conduct String Integrity Test, at User request. o It is hard to analyze this data. o Can see the vibration spectra. o Can evaluate standard motion. o Have good sensors to get some data. o Looking for rotating problems. – Conclusions: o Current knowledge on vibration is minimal. o Current measurement methods are not adequate. o Analysis is not adequate. o Better methods are needed to reduce vibration and improve system reliability. • Q. Can you install sensors on the shaft? – A. Need to deploy sensors with holes in the equipment. – Need to do on a working system. • Q. How can you evaluate the quality of an ESP? – A. Have to test each ESP. • Q. How can you calculate on rotating parts? Can vibration be in phases? – A. We need faster tests. • Q. Do you think the API Guideline o 0.156 is valid. – A. It is OK on the surface. IT is qualitative on the ESP in the well. • Q. Have you tested the models? – A. Not yet. • Q. How realistic is downhole vibration if don't have contact points? – A. This will need to be tested. • Q. Have you looked at critical speed? – A. We are working on it.
Subsea Boosting System in High GOR Gas/Oil Ratio and Viscous Fluid Applica-	**Lissett Barrios, Shell** Stuart Scott, Robert Rivera, Shell	This is about using ESPs for sub-sea boosting in Brazil. • Project: – Sub-sea boosting in Brazil. – Four caissons. – 10,000 – 30,000 B/D per pump. – 1,500 – 2,500 psi boost.

Paper	Author(s)	Summary of Discussion
tions – ESP Technology Maturation	Ketan Sheth, Baker Hughes	– 20 – 700 centipoise. – API 16 – 18 °API. – Gas 350 – 500 Ft^3/Bbl. – 500 – 1,200 psi. – Gas volume fraction: 35 – 70%. – All gas and liquid must be pumped through the ESPs. – Need high volume pumps. – Need to test to verify high velocity pump. – Test for 1,000 hours, start and stop. – Using a multi-vane pump (MVP). – A conventional pump will gas lock. – The MVP will not gas lock. – Has large balance holes; more veins. – Tested at Shell's Gasmer Facility in Houston. – Conducted full-scale test. – Tested at different viscosities. – As the viscosity increases, the horsepower increases. – As the GVF increases, the pump performance decreases. – Conventional ESP performance decreases above a GVF of 40%. – MVP ESP performs OK up to a GVF of 80%. – Conventional ESP pressure decreases at higher GVF. – MVP ESP pressure is OK. – MVP performance improves as viscosity increases. • Conclusions: – Conventional ESPs good up to GVF of 40 – 45 %. – MVP ESP good up to GVF of 70 – 80%. – Run at the highest pressure for best results. • Q. How does density change as viscosity changes? – A. There isn't much change. • Q. Is the differential pressure at the best efficiency point? – A. At the most differential pressure. • Q. To increase the flow rate, do you need to lower pressure and speed? – A. The best performance is at 62 Hz. Need to consider thrust. • Q. Is the stage design optimized? – A. There is potential for it to be optimized. • Q. Do you consider the stage count? – A. We use the maximum number of stages. • Q. How does the MVP give higher head? Does is follow water performance? – A. As viscosity increases, get lower losses. • Q. How do you get flow calculations? – A. We follow the model; do stage-by-stage calculations. • Q. How do you handle gas? – A. The MVP handles gas better and uses better horsepower.
Development of Petrobras Jubar-	**Grant Harris, Schlum-**	This is about an operation in Brazil with Schlumberger. • Field details: – This is a sub-sea field with an FPSO to handle the pro-

<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>te Field: From Project
Basis to Operational Challenges and Solutions</td><td>berger
Luis Vergara, Arthur Watson, Domitila de Pieri Pereirsx, Alan Duncan, Schlumberger</td><td>duction.
– There are 15 wells.
– 17 ^{o}API.
– 4,300 feet water depth.
– The ESP is in a caisson.
– There are emulsion problems.
– The wells are produced by gas-lift.
– The ESP is used to boost the production to the FPSO.
– All oil and gas must go through the pump.
– There is 40% free gas; use an advanced gas handler (AGH).
– Need a long run life to meet the contract.
– There are issues with Pressure and Temperature.
– Design using a systematic approach.
– Integrate the pump and the AGH.
– Use a labyrinth shroud.
– Use an ESP Management System.
– Perform System testing.
– The oil is filtered.
– Conduct extensive Factory Acceptance Test and Site Testing.
– Use an extensive SCADA system to monitor the operation.
• Analysis:
– Installed Nov. 2010.
– Ten ESPs installed.
– All performed for at least 180 days.
– It took an average of 2.9 days to install.
– Longest run time has been 820 days.
– Total has been 4,800 run days.
• Q. Why do Pressure and Temperature change, and how do they change?
– A. We have 4 ^{o}C sea bed temperature. 20 – 150 ^{o}C operating temperature. 50 – 80 bar. A shut down is quick but temperature drops slowly.
• Q. What temperatures do you experience?
– A. There is a lot of fluctuation during commissioning. Then there are 4 - 5 starts per year during normal operation.</td></tr>
<tr><td>ESP Vibration Monitoring: High Horsepower, Deep Water Caisson ESP System</td><td>Neil Slight, Shell</td><td>This paper was not presented.</td></tr>
<tr><td>Alternate No. 1, HPHPS Used to Support Shale Gas Fracturing</td><td>Dana Pettigrew, Nexen Inc.
Wojciech Andy</td><td>This is about using an HPHPS system in Colombia.
• Field description:
– Three projects.
– Swamp land.
– Bad roads.</td></tr>
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Paper	Author(s)	Summary of Discussion
in Norn River Basin	Limanowka, Canadian Advanced ESP Inc.	– CO_2 and H_2S problems. – Use sour water to perform fractures. – Use PD pumps to inject the frac water. – Use ESPs to produce the water. – Have 8 5/8" tubing. – Use produced water – Use HPHPS high pressure pump system. – Conduct tests to see if "sweet" production at risk. – All is OK. – Use to frac the Shale below water zone. – Conducted 330 fracs in 7.5 weeks. – Have a 95% service factor. • Q. Surveillance? – A. Meter to monitor production all the time. • Q. How do you control injection? – A. We control the injection rate during the fractures. – Pump 30 minutes to open the fracture, then follow with sand proppant. • Q. What do you do if you sand out? – A. We use a shutdown on a pressure limit. Start the pump to overcome the sand out. • Q. Do you scourge the H_2S? – A. The H_2S stays in the water which is kept above the bubble point. • Q. How many wells have you fraced? – A. 218 so far. Will do 226 this year.
Alternate No. 2 Implementation of New Seal Design to Improve ESP Performance in Corcel Field		This alternate was not presented.
ISO 15551-1	**Shauna Noonan, ConocoPhillips**	• Development of this ISO document started in Nov. 2009. • It defines Design Verification and Functional Validation. • It covers the manufacturing process and performance ratings. • It covers Functional Evaluation.
Breakout Sessions **#1 – New Technology – Solids, Gas, Cable, and Other Issues!!! Chair – Pat Underwood** **#2 – Is Your Power Quality Causing Motor Failures? Chair – Keith Fangmeier**		
New Technology – Solids, Gas, Cable, and Other Issues!!!	**Pat Underwood, ExxonMobil**	• A goal is to run a high temperature motor below the perforations without the need for a shroud. • Normally need to flow at 1 foot/second past the motor for cooling. Water is different than using oil.

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The motor winding temperature measurement responds too slow to protect the motor.
Some sensors fail
There is an alternate deployed ESP – to 17,000 feet.
Reservoir conditions may change.
Would like to have run life of at least 5 years.
Average lift expectance in ESP-RIFTS is 3.5 years.
Would like to have good performance for sub-sea installations.

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<tr><td colspan="3"></td></tr>
<tr><td colspan="3">Session V
Innovative Installations
Session Co-Chairs
Noel Putscher, Newfield Exploration
Robert Lannom, Zeitecs</td></tr>
<tr><td>Gear Centrifugal Pump Technology Implementation in PDO</td><td>Atika al Bimini, PDO
Bruce Morrow, Harrier Tech.
Atef Abdul Elraouf, Abdullah Al Salmi, PDO Oman
Rashid Al Masgry Marjan Petroleum, Oman</td><td>This is about application of the new geared centrifugal pump technology in PD Oman.

Introduction

There are 4,000 wells on artificial lift.
There are 77 flowing wells.
There are 126 different fields.
In the North of Oman there are:

144 wells on ESP.
112 wells on gas-lift.
111 injection wells.

Why consider the geared centrifugal pump (GCP)?

Lower CAPEX.
Lower work over costs.
Lower power consumption.
Easy to operate.
Reliable.
Can adjust to changing oil production rates.

What is a geared centrifugal pump?

Mechanically driven ESP.
Driven by a rod string.
Gear box to change rotation from 500 to 3,500 RPM using a 7:1 ratio. Some can be 4.5:1 ratio.
There are no electrical components down hole.
Can use a gas anchor for gas handling.
Can use a guided rod string with stabilizers. This projects the tubing and the rods.
Uses a PCP drive head to rotate the rods.

Advantages:

Obtain ESP rates with better efficiency, approaching 90%.
Reduced work over costs.
Can handle gas.

Project objectives:

Test the performance of the system

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Paper	Author(s)	Summary of Discussion
		– Evaluate for one year. – Try in horizontal wells. – Depths: 950 – 1,200 M. – Rates: 200 – 500 M^3/Day. – 7” casing. – 1” and 1.25” rods. – 3.5” and 4.5” tubing. – Run a downhole gauge. – Use three stabilizers per rod deep in the well; 3 in the middle, one high in the hole. – Operate with a VFD. – Monitor with the SCADA system. • Initial experience: – First well ran for 4 months then had rod failure. – Efficiency was about 70% and sometimes up to 80%. • Pilot study: – Run on 6 wells. – Evaluate for one year. • Go forward plan, if pilot is successful: – Install on 20 wells in 2014. – Install on 300 wells in 2015. – Expand to the South of Oman. Replace some PCPs. • Q. In horizontal wells, where is pump installed? – A. In the vertical section. • Q. What is the tolerance to work through dog legs? – A. Same as for an ESP. • Q. Have you considered using co-rod? – A. Possible, but haven’t tried yet.
Alternative Deployment of ESP System in South America	**Nicholas Garibay, Zeitecs** Carlos Blum, Jacksson Jimenez, Lein Pozo, PetroAmazonas Neil Griffiths, Zeitecs Luis Constante, Edison P:adilla, Baker Hughes	This is about using ESPs in the North of Ecuador. • Introduction: – The ESPs in the field need to be changed. – An alternative method of deployment is used. – There are 46 ESPs in the field. – Production is 13,400 BOPD. • Business case: – Use shuttle deployed ESPs, through tubing. – Can retrieve the ESP and the motor. – Failed ESPs retrieved with wire line or rods; therefore rigless. • Test well. – This was a “vanilla” case. – 400 series ESP. – Completed in Sept. 2012. – Work over time was 12 days. – New installation in 3.5 days. – ESP failed 12/9/12. – Fixed on 12/13/12 without a rig, using coiled tubing. – Took 2.5 days to fix. – Our target is 2 days. – Crew reduced from 30 – 7 people. • Benefits: – Less rig costs.

Paper	Author(s)	Summary of Discussion
		– Less downtime. – More production. • Q. What failed initially? – A. ESP motor. • Q. You fix with sucker rods and coiled tubing. Why not wire line? – A. Rods are available. Hard to get a wire line unit. • Q. How do you measure downhole performance? – A. Via the ESP cable. • Q. What is the total cost comparison? – A. Use a rig to install the motor. Use rig-less to work over; less downtime. • Q. Could you pull with slick line? – A. Could, but unit went to PDO. • Q. Could you use in a smaller casing size? – A. This is designed for use in 7: casing. • Q. Can this be done with any ESP? – A. Yes.
A Novel Approach to Retro-fitting ESP's in to Existing Subsea Wells	**Torstein Vinge, Statoil** **Niek Dijkstra, Schlumberger** Norman Lovie, Schlumberger	This is about retro-fitting ESPs in subsea wells. • Introduction: – Retrofitting ESPs in subsea wells using alternative deployment methods. – There are challenges in working with subsea wells. – This is in ultra-deep water. – There are 500 subsea wells in the North Sea. – Gas-lift is not an option for these wells. – Therefore, consider an ESP retrofit approach. – ESPs are used to maximize reservoir recovery. – Two types of tubing hangers were evaluated: 7" and 5.5" tubing. • Conclusions: – It is feasible to install ESPs with coiled tubing. – There are challenges with doing this with a wet tree. Better to do work on rig or platform with dry tree. – It is easier to work on the surface. • Process: – Make up the system on the rig floor. – Work through dry Christmas tree. • Q. Do you have dual barriers? – A. Can open on over pressure. May have to kill well to prevent a problem. • Q. How do you address the capstand effect? – A. We use the standard approach. • Q. You use coiled tubing? – A. Yes. • Q. Do you need special metallurgy? – A. We need a special coiled tubing to last a long time. The coiled tubing environment is not abrasive so holes in the CT are not a problem.
First Successful	**Eugene**	This is about a full retrievable ESP via wire line in the Congo. • Introduction:

Paper	Author(s)	Summary of Discussion
Offshore Installation of Wireline Retrievable ESP Technology in Congo	**Bespalov, GE Tita eni Congo** G. Rissa, S. Pilone, D. Drblier, Zeiteces D. D. Okassa, GE	– The goal is to use wire line, slick line, or coiled tubing. – The objective is to reduce CAPEX and OPEX. – The project started in 2010. – They have 5.5" tubing, 9 5/8" casing. – The system was tested in Houston in 2011. – It was installed in 2012. – The initial test well had low deviation, low sand, low GOR. – The field is 52 Km. offshore. – The goal is to have a reasonable run life. – The system is partially semi-permanent, partially retrievable. – It uses a rotary gas separator. – It has a deep-set safety valve. – It uses a redesigned wellhead to allow cable penetration. – It was installed on 3/22/2012. – The installation time was 4.5 days. – On Platform A, with no rig saved $6.7 MM. – On Platform B, with no rig saved $1.2 MM. • Lesson: – Use of a rod string is feasible. • Conclusions: – The first installation was successful. – ESP installed 4/5/12 and still running. – There are large rewards if rigs are not available. • Q. Was there a problem to release the tool? – A. We couldn't release the tool. A rod string would be more flexible. • Q. What are the economics of rod string vs. wire line? – A. We used a rod string but will look at wire line for the future. Will need special wire line. • Q. Is cost of 5.5" with cable also economical? – A. This does increase the cost of the tubing and cable. Also, cable lasts 5 years so a work over will be required eventually. • Q. Is high GOR in well a problem? – A. We use a packer for isolation. Use a gas separator to handle the gas.
Downhole Oil and Water Separation – A New Start	**Ed Sheridan, Ian Ayling, Baker Hughes**	This is about the re-birth of the downhole oil/water separation system. • Introduction: – This has previously been a problem. – There is a new system now being used in China. – It is a new approach to keep it simple, using standard equipment. – Can be used to inject water into a zone that is either above or below the production zone. – Uses a simple method to get the production to surface. – Uses a hydro-cyclone to separate the oil and water. – Oil and some water are lifted to the surface. – System uses two ESPs and two VSDs.

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<tr><th>Paper</th><th>Author(s)</th><th>Summary of Discussion</th></tr>
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Can inject into a deeper zone through a single line.
Casing must be greater than or equal to 7”.
Cut greater than 85% water.
Need to have good data on the production zone and the injection zone.
Need to choose good candidate wells.
Need to run an injectivity test.
Can handle more than 3,000 B/D.

Anadarko in China:

Have surface contracts.
Choose candidate wells that produce more than 300 BOPD.
Have a good injection zone.
The injection zone relatively close to the production zone.
Conducted a test of the surface equipment in LA.
Inject 9,000 B/D.
Oil production was increased.
System was installed in 2010; it is still working.
The control logic is working.

Q. If the injectivity improves, how is the system controlled?
A. We use the lower ESP to control this.
Q. What sampling do you need to do at the surface?
A. Initially we performed hourly samples. Now we sample once each two months.
Q. Are there any solids?
A. No.
Q. How do you sample if zone contains salt?
A. Don’t know.
Q. Could you use a downhole meter?
A. This would be possible.
Q. Is the H_2S a problem?
A. We need to perform good application engineering.
Q. What are the factors that affect the economics?
A. Need a good injection zone.
Allow Anadarko to solve operational problems.
Need to look at each well to determine if it will work.

</td></tr>
<tr><td>Alternate No. 2, Artificial Lift Surveillance and Analysis, Optimize Well Production and Reservoir Management of Oilfields in Angola</td><td></td><td>This alternative paper was not presented.</td></tr>
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Paper	Author(s)	Summary of Discussion
	Wrap-Up	
2013 ESP Workshop Summary	**Noel Putscher, Newfield Exploration**	• Workshop summary. – This year there are 630 attendees, a new record. – There was a strong emphasis on safety for all attendees. – There were 29 technical exhibits. – There were 29 technical presentations. – There were 8 sponsors. – 85 people attended four Continuing Education classes. – For the Workshop: ○ 39% of attendees were from Operating Companies. ○ 61% were from Service Companies.
	Closing Comments	
2013 ESP Workshop Closing Comments	**Noel Putscher, Newfield Exploration**	There were very brief closing remarks. Basically, everyone was thanked for attending.