Problems encountered in stripper wells engineering essay

Engineering

1. Water Loading In Stripper Gas WellsProblem: One of the most troublesome problems for stripper gas well operators is the water that is produced along with the gas; if it accumulates in flow lines or builds up at the bottom of a wellbore it will reduce gas flow rates below economic levels. Water in flow lines is difficult to remove and contributes to corrosion, while removing water from wellbores can be a continual expense in terms of pump parts and maintenance, power costs, and pumper time. Proposed Solution: Develop a simple, in-line device that acts to redirect the liquid phase in pipelines and tubing, allowing the gas phase to more effectively carry the liquid phase along a pipeline or out of a well. Such an approach would simultaneously improve production rates and reduce operating costs. Background and Results-to-Date: In 2002 the SWC funded several projects with Vortex Flow, LLC to adapt an existing technology (for conveying solids over long distances in pipelines) to improve the flow characteristics in stripper well flow lines and wellbores. Prototypes had been fabricated and field-tested on a limited basis, but SWC involvement enabled Vortex Flow to:• Quantify the efficiency of the Vortex Flow Unit installed in an actual gas gathering system,• Determine the optimal operating conditions,• Perform additional design improvements, and• Complete the design and fabrication of a down hole version of the unit. A second project with the SWC in 2003 enabled Vortex Flow to install and field test multiple down hole units with Marathon Oil Company, and collect the data needed to refine the technology. The Vortex Flow technology takes a disorganized, multi- phased flow stream and transforms it into a helical flow pattern where a slower-moving liquid phase runs along the inside wall of the flow line or tubing string and the gas moves through the centre of the

pipe. This vortex (rotating) pattern prevents liquids from dropping out of the flow and permits efficient movement over long distances and substantial changes in elevation and direction. The down-hole tool lowers flowing bottom-hole pressures in gas wells by reducing liquid Installing a down-hole version of the tool holdup in the tubing. In many applications, they reduce the slugging that is common when lifting large volumes of water with minimal gas. The accompanying reduction in friction losses reduces the pressure drop and thus increases production rate. The down-hole tools, made of 304L stainless steel, are being fitted to 0. 6 inch through 3. 5 inch tubing inside 2 7/8" inch OD and larger tubing/casing sizes. Installation is easy; the tools simply thread on the bottom of the tubing. Perhaps even more important, the device has no moving parts and requires no power source or maintenance. Marathon successfully deployed these new tools to convert low volume gas wells that were being mechanically dewatered into flowing gas producers. By eliminating down-hole pumping equipment, variable and fixed costs decreased dramatically; from an average $875 per month to $15 per month. Considering installed cost, the tools paid out in about seven months. In two cases, since prior failures with associated downtime were eliminated, about 2. 7 MMcf per year of deferred production was saved. This $10, 000 cash-flow benefit essentially paid for tool installation.

Ongoing Activity and Future Plans:

A third project with the SWC in 2004 was designed to determine the benefits of combining a slickline-set through- tubing, downhole version of the Vortex Flow device (the DXR tool) with other low cost lifting methods such as surfactants, plunger lift, velocity strings and intermitters. The expectation is that a DXR tool combined with these methods can lower the critical gas rate required to keep a well flowing by as much as 60 percent, and replace more expensive traditional lifting methods such as rod pumps. Vortex Flow developed the new slickline-deployable model and has been installing it in customers' wells since January 2004. Vortex Flow, LLC is now a successful commercial enterprise. In December 2004 the company won the Platts Global Energy " Newcomer of the Year" Award for its " revolutionary fluid dynamics technology that … will extend reservoir life and potentially save its customers many millions of dollars." Vortex Flow developed the new slickline set & retrievable model and has been installing it in customers' wells since January 2004. The DXR tool can be set in a profile nipple or collar stop. 2. Develop a Simple and Effective Way to Remove Water from Stripper Gas Well Flowlines(Construct and Test a Simple Pump for Dewatering Gas Wells That is Inexpensive to Operate)Problem: Stripper gas wells still capable of producing gas often must be shut in when the cost of removing produced water from the wellbore exceeds an economic limit. Just a few tenths of a barrel per day can kill gas production. Regular removal of this water as it accumulates in a well increases average gas production, but conventional fluid removal techniques using beam pumps, periodic swabbing with workover rigs, siphon strings and tubing plungers havephysical limitations and require significant capital, operating and maintenance investments. For marginal wells, these costs can lead to premature abandonment of producible gas. Proposed Solution: Develop a tool that has few moving parts to wear out, is simple to operate, requires minimal monitoring, and utilizes the natural pressure of gas in the wellbore to lift the water out of the well on a regular basis. Background and Results-to-Date: The SWC funded three projects with Brandywine Energy and Development Co. (BEDCO) during 2001, 2002, and 2003, to develop and test an automatic pump for removal of liquids from a wellbore. The new pump, called the Gas-Operated Automatic Lift (GOAL) PetroPump, is designed to freely operate within the well casing similar to a free-falling piston, rising when GOAL PetroPump tools (red tool at left is original design, smaller tools at right are current design). One of the important features of this system is its ease of operation. It does not require a great deal of special training for the pumpers that will operate it, often small independent sub- contractors employed by the producing company. It is also a relatively low maintenance system. One issue with manually operated tubing plungers has been wear and tear—the sealing cups often need to be minimize costs, some maximize gas production, this tool does both. It’s an important advancement because it approaches the performance of a mechanical rod pump, while still being simple to operate and with much lower maintenance. It’s great." Ongoing Activity and Future Plans: The GOAL PetroPump is now available commercially and is being used by a number of smaller independent operators in the Appalachian BasinRod pumps and pumpjacks call into play another whole set of maintenance and operations problems. The PetroPump avoids these costs while approaching the same degree of liquid removal capability. Lenape Resources, one of the larger automatically closes the bypass. Flexible sealing cups surround the tool, creating a circular seal with the inside diameter of the casing. As gas pressure builds in the well below the tool it is lifted up the wellbore, pushing the fluid load to the surface and out the topside of a wellhead lubricator. Follow-on gas production is then produced from below the tool on a bottom side port in the same lubricator. The tool is " smart" in that after ascending the wellbore to the lubricator it does not latch into a catcher to await physical tool design and tested it in a number of under-performing wells. During a third project, the GOAL PetroPump was installed in three additional wells that were open-hole completions. The wells were sliplined with 41/2-inch casing and an openhole packer. This test was undertaken due to the large number of openhole-completed stripper wells (perhaps more than 10, 000) that stand to benefit from the application of this technology. The tool has evolved significantly throughout the development and field-testing process. The original tool independents in New York State with 14 employees, operates about 500 wells in the Northern Appalachian region, many of which are stripper wells. The company installed the GOAL PetroPump in a 3, 200-ft Medina formation completion that required periodic soaping and swabbing to remove liquid and produced about release by a human attendant. The on-tool actuator valve assembly senses tool pressure and, at such time as wellhead pressure declines to within a preset limit of sales-line pressure, opens and allows the tool to automatically descend for another cycle. It was more than 6 feet long, weighed over 100 lbs and had more than 60 components. The current (fourth-generation) design can accommodate 4-inch or 3-inch ID casing or tubing, has just 14 components, is only 38 inches long and weighs less than 45 lbs. Production after tool installation averaged 3, 416 Mcf/year and payout was achieved in 8 months. Several other subsequent installations by Lenape resulted in similar increases in production. According to John Holko, President of Lenape Resources.

3. Develop a Fast and Reliable Tool for Identifying Under-Performing Stripper Gas Wells

Problem: Stripper gas well producers often do not have the time or money to collect and evaluate the pressure and production data that can help them determine if wells are producing up to potential or if remedial work could improve productivity. This problem is compounded by the fact that many stripper gas wells, particularly in the Appalachian Basin, produce from multiple zones in low permeability fractured shale and sandstone formations, a situation that can be particularly difficult to analyze. As a result, operators may not be able to select the best candidates for workovers, which can lead to curtailed productivity and misdirected investments. Proposed Solution: Develop and distribute a reasonably- priced software product that producers can use to quickly and reliably evaluate stripper gas wells, and that is designed specifically for the low-permeability, multiple-completion wells typical of stripper production areas. Background and Results-to-Date: Production type curve analysis is a well-established analytical approach that compares the pressure response of a well during production over time to predict responses generated using detailed mathematical models of a reservoir’s behaviour. By matching the actual response to predicted behaviour, engineers can determine if a well is producing efficiently or if it might benefit from a stimulation treatment or recompletion. The analyst can take this one step further and predict how much of an increase in production might occur for a given workover investment. Performing tests and analyses on many wells allows a producer to see where workovers will result in the highest incremental increase in production and the greatest return on investment. Under funding from NYSERDA and the Gas Research Institute, Advanced Resources International, Inc. (ARI) had developed a production type curve analysis program (called METEOR) designed specifically for use with commingled completions (wells that produce from multiple zones simultaneously). While this program offered the capability to perform a detailed two-layer production type curve analysis, and generated permeability, stimulation, drainage area, and recovery estimates for each layer, the software lacked several features that would enhance its usability.

4. Develop A Downhole Corrosion InhibitorDeployment System For Plunger Lift Wells

Problem: Research suggests that 86 percent of failures in plunger lift systems are a result of corrosion damage brought on by produced brine. Corrosion inhibitors can help solve this problem, but the effectiveness of corrosion inhibition treatments in gas wells is limited. Many of these wells employ a packer that prevents liquid circulation to the tubing via the casing-tubing annulus. The common alternative is to pump corrosion inhibitor (generally in a diesel carrier) down the tubing, wait a period of time, and then flow the liquid back up the tubing, allowing it to coat the inside surface. However, if the well has insufficient bottom hole pressure to flow back the inhibitor, a swab unit must be employed to re-establish production following the treatment. This defeats the purpose, as the running of a swab wipes away the film that was just applied. The inability to effectively deliver corrosion inhibitor to plunger lift gas wells leads to equipment failure, high operating costs, and premature abandonment. Proposed Solution: Develop a plunger lift system with an inhibitor-loaded plunger designed to deposit the chemical at the bottom of the tubing string. Design the system to automatically load the plunger with chemical upon arrival at the surface and transport the payload to the bottom of the well on each cycle. Make the system compatible with existing plunger lift equipment and simple to install and operate. Background and Results-to-Date: Composite Engineers, Inc. was awarded a grant through the Stripper Well Consortium to develop this patented system. Extensive effort was devoted to key elements of the design: a chemical chamber to be located on top of an existing plunger lift lubricator, a valve mechanism capable of loading the chemical upon arrival of the plunger at the surface, and a plunger capable of unloading the chemical payload at the bottom of the well. The system developed by Composite Engineers is unique in that it continually treats the well tubulars, eliminating any need to shut in the well and lose perhaps several days production. The system can be easily installed on existing plunger lift systems with common tools and without the need for a service unit. This installation can even be carried out during a well's normal " shut-in" cycle, avoiding any interruption of production. Another feature of the system is the option of deploying multiple chemicals utilizing a single system (i. e., corrosion inhibitor, foaming agents, salt dispersants, etc.). One has to assure the chemicals are compatible with each other due to possible mixing in the chemical chamber over time. Multiple chemical pumps can be timed to deliver individual chemicals to the plunger on opposite cycles. Finally, the system is very simple to maintain, with few moving parts. If problems do occur, the well can continue to be operated as usual with the chemical system off line. Various prototypes were tested in the lab before being deployed in a 200-foot deep test well. After modifications based on the test well data, two systems were deployed in a field near Lafayette, Louisiana known for corrosion problems. Corrosion coupons were installed 90 days prior to installation of the systems to establish a baseline rate of corrosion and the tubing strings of both wells were pulled and inspected prior to installing the chemical systems. Once deployed, the gas- driven chemical pumps were each set to pump 2 1/2-quarts per day. The field trials were terminated after 168 days.

5. Develop an Economical Electrical Submersible Pump for Low Volume Stripper Wells

Problem: Almost all oil and gas wells produce amounts of sand, scale, and corrosion debris. Stripper wells typically do not produce fluids at high enough velocity to removethis material, requiring periodic clean outs to maintain flow rates. This remedial work is costly and results in production downtime. Proposed Solution: Develop an inexpensive, small- diameter electrical submersible pump (ESP) that can be easily deployed inside casing on small diameter plastic tubing that can double as a conduit for produced fluids to reach the surface. Design the pump based on a hydraulically driven diaphragm that is tolerant of debris-laden fluid. Employ the small diameter plastic tubing to increase pumped fluid velocity and more effectively sweep the debris to the surface. Such a system should also allow placement of the pump below the perforations, leading to greater pressure drawdown and improved production rate. Background and Results-to-Date: Pumping

Solutions Inc. had developed a hydraulic diaphragm electrical submersible pump (HDESP) with the ability to pump sandy fluids at significantly reduced power and purchase costs relative to a conventional ESP. Hydraulically driven diaphragm pumps are mainly used in mining operations to pump slurries from the bottom of the mine to the surface for processing. The SWC funded an effort to develop and demonstrate a cable-suspended version of this pump using powered surface reels to deploy three strands: steel wire rope for support, plastic insulated electrical cable for power, and fabric reinforced polyethylene plastic tubing for the produced fluid. The reels were mounted on a portable trailer that can be towed by a normal oil field truck and operated by one person. The cable suspended pump (CSP) was successfully deployed a total of four times at the Rocky Mountain Oilfield Testing Center (RMOTC) after the installation trailer was completed in November 2002. The test deployments led to improvements in the CSP design; specifically, to the suspension cable connection, to the tubing and electrical cable attachments to the suspension cable, and to the drives used to deploy the tubing. The final test was conducted in April 2003 in a well completed in the Shannon formation at900 feet. The pump was successfully deployed in less than 4 hours, including final hook-up and pump-up.

Ongoing Activity and Future Plans:

The success of these tests helped to achieve to full commercial deployment of both the HDESP and the CSP deployment system following acquisition of Pumping Solutions, LLC by Smith Lift, a large, international artificial lift supplier. Between 100 and 150 HDESP installations have been made in stripper wells over the past two years to measure the performance of the diaphragm pump. To date, the average run time has been about 4 months, with run time improving constantly with design changes. The HDESP contains no electronics, few moving parts, and utilizes oilfield proven technologies such as standard API balls and seats and proven ESP motor and cable technology. HDESPs have the ability to pump up to 1. 5 percent sand, will pump off without damage, can provide mixed flow pumping (gas and liquid) and have exhibited 66 percent less power consumption than conventional ESPs. This performance is from an all-stainless steel and rubber pump that weighs about 100 pounds, is 3 3/4 inches in diameter and costs less than half the price of a conventional pump. A 13/4- inch, hydraulically operated version that can be run inside tubing is currently being developed.

6. Build and Test a Novel Design for a Low Cost, Variable Capacity, Low Volume Gas Compressor

Problem: Stripper gas wells produce relatively low volumes of gas at low pressures, and even new wells drilled in marginal areas exhibit flow rates that decline relatively quickly. Sizing a compressor to reduce the wellhead pressure is difficult, and even smaller sized reciprocating compressors are still too large and expensive for individual stripper wells. As a result, these wells are shut in while producible gas reserves remain in the reservoir. Proposed Solution: Build and demonstrate a novel pump/compressor that employs a spherical design that provides the largest internal volume to surface area ratio possible for maximum efficiency. Design the compressor with a variable capacity so that it can be easily adjusted to meet changes in flow rate without changing the rotation rate of the drive shaft. Background and Results-to-Date: The Weatherbee Positive Displacement

Compressor/Vacuum Pump is a patented device that, due to its novel spherical design, is substantially reduced in size and weight over conventional compressors. For example, the 81/2 inch-sized Weatherbee Pump weighs only 75 pounds and has 244 cubic inches of displacement. A reciprocating compressor of the same size capacity would weigh on the order of 600 pounds. A 4 inch- sized model has a 25 cubic inch displacement; enough to handle a stripper gas well producing 50 Mcfd at typical line and wellhead pressures. The variable volume control mechanism works like a throttle on an engine, allowing he compressor capacity to be easily adjusted as a well's flow rate drops over time. The device uses only the energy necessary to compress the gas that the well is producing, thereby saving on energy use. Because the Weatherbee pump is a ported device, without the valves and springs common to conventional reciprocating compressors, it should have lower maintenance and operating costs. In addition, the direction of flow can be completely reversed without disconnecting the pump or changing the rotational direction of the input shaft. The Stripper Well Consortium has funded work on this pump in two phases. Under Phase I, W&W Vacuum and Compressor Inc., (W&W) selected and qualified an engineering and manufacturing facility (Athena Manufacturing, LP) to re-engineer the preexisting 81/2 inch pump and build a new 4 inch configuration prototype for stripper well applications. First, the original mechanical drawings were converted into a three-dimensional computer-aided-design (CAD) electronic format, and two separate configurations for the pump seals were selected: one fluid- based and one mechanical-based. Initial testing proved that the mechanical-based configuration would be the best choice. W&W solicited and received seal design assistance from a number of seal manufacturers, and after extensive testing it was determined that engineered polymer (Radel and Delrin) seals would not work. W&W then began working with Boeing's engineers to develop an energized type seal that features a spring-loaded carbon composite seal element housed in a stainless steel ring. A total of five compressors were built during the prototype development process. Compressor housings, vanes and shafts were manufactured from a number of different materials. A variety of bearing types and assembly configurations were evaluated and each compressor was tested using a custom test bench. This bench testing revealed a substantial amount of information, often in the form of post-failure analysis. Phase I funding was depleted with the successful manufacturing of an operational prototype while simultaneously designing and developing two different compressor seal configurations.

7. Improve The Efficiency Of Treatments To Reduce Water Production From Stripper Oil Wells

Problem: Many stripper oil wells, particularly in older fields that are under waterflood or have reservoirs with strong water drives, produce large amounts of water and relatively small amounts of oil. High water cuts are characteristic and many wells have to be shut in due to high water-oil ratios. Gelled polymer treatments have been used to reduce waterproduction, prolonging the life of some wells and increasing oil recovery. These treatments typically result in a period of flush oil production, followed by a gradual return to high water cuts. Finding a way to prolong the treatment's effectiveness would allow these wells to remain on production longer, producing a larger percentage of the oil remaining in these fields. Proposed Solution: Over 300 gelled polymer treatments have been applied in the Arbuckle formation in Central Kansas. A typical treatment consists of injection 3, 000 to 4, 000 barrels of gelant into the reservoir followed by an oil or water flush of about 100 barrels to clear the tubing and casing as well as to establish permeability in the reservoir rock when the gel forms. The well is shut in for a week or more while the gel forms and then the well is put on production at a reduced rate. The gel preferentially reduces the permeability of the formation to water in the area near the wellbore that has been treated. A DOE-sponsored research project at the University of Kansas has revealed that it is possible to further reduce the permeability to water by dehydrating the gel after placement, by controlled injection of oil. Water is " squeezed" from the gel as flow paths are created by the injected oil. Also, the gel that remains after dehydration exhibits increased strength due to its higher polymer concentration. This mechanism (termed disproportionate permeability reduction) reduces water permeability by at least an order of magnitude in laboratory tests. This project proposes to demonstrate the process in the field for the first time.

8. Development of an Accurate, Low-Cost, Portable Production Well Tester

Problem: Producers must make operating decisions regarding high-water cut stripper wells without accurate information on the relative amounts of oil and water being produced over time. Acquiring such data requires equipment that is either unavailable at most stripper well locations or is very expensive to purchase or rent. As a result, stripper well operators must choose the lowest cost option and settle for poor accuracy, or forgo testing. In the end, their well's production is not optimized and oil and gas reserves are lost. Proposed Solution: Design, construct, and demonstrate a portable electronic production well tester capable of providing accurate individual well test data at a reasonable cost. Background and Results-to-Date: Many stripper wells produce significantly more water than oil. Secondary oil recovery methods (usually waterfloods) involve the production and handling of large volumes of water, small volumes of oil and, sometimes, natural gas. Also, many mature fields produce large amounts of water with smaller amounts of oil and gas under primary production. Accurate testing of high-water cut wells is important to determining reserves and the economics of the additional investments needed to improve oil and gas production and/or reduce water production. Production testing is normally done using permanent, centralized separation and metering stations or portable testers, either of which can employ expensive electronic testing equipment. Centralized systems require that extralines be installed and maintained. The cost of installing these lines or even simply maintaining them for stripper wells can be prohibitively expensive. Portable systems allow testing at individual wells on an as-needed basis, but current low cost, portable testers (which cost on the order of $10, 000) are not accurate due to sampling frequency and gas interference problems. High cost portable units (which can range from$50, 000 to $100, 000) are out of the economic reach of most independent operators. In addition, many stripper wells do not have electric power available to operate these testers at the well site. This research project will develop a portable tester for high water cut wells, demonstrate it in the field, and compare it’s performance to that of current testers. The testing parameters for the prototype are: total liquid rates of 100 to 1, 000 BPD, water cuts of 0 to 100 percent, gas rates of 0 to 25 MCFPD, and oil gravities of 20 to 40 degrees API. During 2004, the investigators researched and evaluated a wide range of possible testing configurations and equipment options and selected a configuration for a portable electronic tester that is both accurate and has the potential of meeting the capital cost target ($20, 000 to $25, 000 range) in a second generation unit. A prototype is currently being constructed and will be used to carry out a number of field tests during 2005. Ongoing Activity and Future Plans: The unit will be tested in 30 to 60 southern Oklahoma wells, including Oak Resources wells during 2005. The results will be compared to those obtained from commercially available, low-cost portable well testing equipment and the researchers will evaluate the outcomes and report the findings. The final report will identify the best measurement methods and the key components necessary to construct a second-generation portable tester within the target capital cost range. Eventually, the design can be extended to very low liquid rates and gas wells.