Well Control

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In the last 6 years, the rig count has more than doubled from approximately 1,600 rigs in 2002 to more than 3,500 rigs operating worldwide in 2008. This phenomenal growth has been supported by increasing oil prices that have gone from less than USD 20/bbl in January 2002 to almost USD 146/bbl in July 2008 before falling off drastically in the following weeks. Assuming normal staffing and crew-rotation requirements, more than 30,000 people were needed to operate the 1,900 rigs that were added to the fleet during this period. Experienced personnel are spread thin as new hires are brought onboard to staff the rigs. This influx of new personnel into the industry created the additional burden of needing to train the new hires in the fundamentals of well control. It also makes it necessary to train an increasing number of personnel at the supervisory level as they advance to fill new positions.

Most people agree that the rig crew is the first line of defense against well-control problems. They are the "boots on the ground" that are charged with recognizing the first signs of impending trouble.

On the other end of the spectrum is the increasing number of operator and service-company personnel who are focused on advancing basic well-control principles to accommodate deeper, higher-temperature wells by use of exotic oil-based drilling fluids and by use of various methods of managed-pressure drilling.

The advanced well-control theories are supported by increasingly sophisticated computer models that account for numerous physical changes that become significant only at the elevated pressures and temperatures and increasing depths associated with these extraordinary wells. Interestingly enough, advanced well-control modeling is finding an increased number of uses in less-extreme wells and actually is assisting with teaching the fundamentals that apply to the broader class of wells.

The monumental tasks of training new personnel, training more personnel to higher levels of competency, and developing models to handle the extraordinary drilling environments accurately are all being met with surprisingly good results.

Developments in well-control modeling are providing useful insight into actual downhole conditions and fluid behavior that enables making much better decisions—both in planning and in actual well-control events. JPT

Well Control additional reading available at the SPE eLibrary: www.spe.org

SPE 112761 • *"Simulations Comparing Different Initial Responses to Kicks Taken During Managed-Pressure Drilling" by Asis K. Das, SPE, Blade Energy Partners, et al.*

SPE 115019 • *"Validation of Blowout-Rate Calculations for Subsea Wells" by P. Oudeman, SPE, Shell*

SPE 113842 • *"RFID Actuation of Self-Powered Downhole Tools" by P.M. Snider, SPE, Marathon Oil Company, et al.*

Hydrostatic Packers Manage Lost Returns, Well Control, and Cement Placement

A hydrostatic packer consists of a column of light fluid pumped into the annulus or drillstring to cause the total hydrostatic head (HH) to be equal to or less than the integrity, which is a function of the fracture-closure stress (FCS). This results in a positive surface pressure that allows accurate placement of cement, lost-returns treatments, or other fluids in situations where they otherwise would be overdisplaced if a full column of drill-weight mud were used. The operator has used hydrostatic packers in one area for 15 years and globally for the last 7 years.

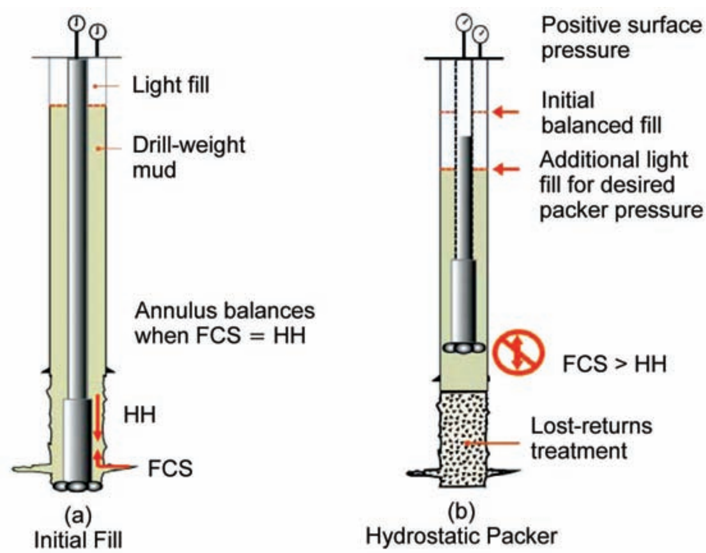

Fig. 1—Annulus losses stopped by filling with light fluid until HH equals FCS in loss zone.

Introduction

The majority of severe losses are a result of fracture propagation, and this is the type of loss where hydrostatic packers are used. Fracture-propagation losses occur when wellbore pressure exceeds the integrity, which is largely composed of the far-field stress holding the borehole closed plus some lesser near-wellbore stress effects. When wellbore pressure forces the rock open, a tall, narrow fracture is formed. Drilling fluid then propagates and extends the fracture, and losses continue. After the fracture is created, the adjacent formation stress continues to attempt to close it. This stress is referred to as the FCS. The FCS may increase slightly because of a variety of effects, but it cannot fall below the minimum far-field stress. As long as the wellbore pressure exceeds FCS, losses and fracture growth will continue. Conversely, if wellbore pressure is reduced below FCS, the far-field stress forces the fracture closed and losses stop.

The behavior observed at the surface when the HH exceeds the FCS is that the well will not stand full. The lost-returns fracture opens because the force holding the rock closed is less than the static head (force) being applied. Because of well-control concerns, the common practice then is to fill the annulus continuously with drill-weight mud. Losses continue as long as the annulus is filled because the head remains higher than the resisting FCS at the loss zone. The FCS continues to exert a constant and reliable force against the bottom of the fluid column, but losses continue because the FCS is unable to support a full column of drill-weight mud.

Hydrostatic packers are used in the displacement of all treatments when the well initially will not stand full. Another scenario in which hydrostatic packers are used is in the management of underground flow that follows lost returns. The common response to underground flow is to establish a continuous injection rate to flush the influx to the loss zone.

The full-length paper discusses the manner in which the FCS in the receiving zone controls downward flow and how the closing stress is built to stop flow. Hydrostatic packers have been used in these situations to control the placement of pills or cement during the stress-building process.

In general, hydrostatic packers are used in specific situations where they reduce operational risk, save rig time, or achieve a significantly higher certainty of success. They now have a role in almost all company operations in which the well will not stand full.

Hydrostatic-Packer Concept

A hydrostatic packer is a column of light fluid pumped into the annulus or drillstring to cause the total head at the loss zone to be equal to or less

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 112657, "Use of New Hydrostatic-Packer Concept To Manage Lost Returns, Well Control, and Cement Placement in Field Operations," by **F.E. Dupriest,** SPE, ExxonMobil Development Company, originally prepared for the 2008 IADC/SPE Drilling Conference, Orlando, Florida, 4–6 March. The paper has not been peer reviewed.*

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

than the FCS. The term hydrostatic packer arises from the use of reduced HH to achieve an arrangement that acts much as a packer, which is to say that it allows control of the position of fluids in both the annulus and drillstring

The simplest version of a hydrostatic packer is a practice that is quite common in the industry, which is to fill the annulus that will not stand full of drill-weight mud with light fluid until losses stop. The annulus stops taking fluid when the head has been reduced, by the addition of light fill, to be equal to the FCS in the loss zone. The system then is balanced and stable because the force pushing upward on the bottom of the column (FCS) equals the reduced head pushing downward. This is the starting point for installing a positive-pressure hydrostatic packer **(Fig. 1a).** A preventer is closed and additional light fill is forced into the annulus to reduce the head further (Fig. 1b). This requires, and results in, positive surface pressure because the head is now less than the resisting FCS at the bottom of the hole. When the desired surface pressure is achieved (100 to 300 psi), pumping stops. The annulus column now is locked in place and cannot move up or down. It cannot move upward because the preventer is closed, and it cannot move downward because the FCS is higher than the head. The resisting force at the loss zone is FCS, and therefore the well is underbalanced to FCS and not to the pore pressure.

Once the annulus column is locked in place with an annulus packer, a similar process is used to prevent overdisplacement of any treatment material pumped down the drillstring. The treatment is pumped followed by a precalculated volume of drill-weight mud. The displacement is switched to light fill at a specific point so that when the treatment is in its final position, there will be sufficient light fill in the drillstring to cause the total column to be underbalanced to the FCS. Again, the designed surface pressure is achieved and the column is locked in place.

The process is effective regardless of the treatment pumped. For example, if heavy cement is used, additional light fill is necessary to make the total head underbalanced to the FCS, but the process still is essentially the same. The top of cement can be stopped precisely at any desired depth. Likewise, the height of light fill also is varied, depending on the given FCS. The lower the FCS, the greater height of light fill required to achieve the desired underbalance.

The use of hydrostatic packers also allows the operator precise control over squeeze operations once the treatment is in place. If the desire is to squeeze only 1 bbl of lost-circulation material (LCM), 1 bbl of displacement fluid is pumped into the top of the string, and 1 bbl is squeezed to the fracture. The loss zone cannot take additional fluid because the head is still underbalanced to the closing stress. This control has proved to be critical in lost-returns treatments where hesitation squeezing is required.

Risk Management

Hydrostatic packers are reliable because the far-field stress they work against is reliable. There have been no failures to control overdisplacement. The operator also has had no well-control, stuck-pipe, or other trouble events resulting from their use. However, the high success rate is partially a result of the packers being actively managed by well-trained personnel. The operator's rig supervisor and engineering personnel receive formal training in fracture mechanics, lost-returns mitigation, and hydrostatic-packer design. When unexpected events or pressures are observed, rigsite personnel have the knowledge required to interpret the data and redesign the packer or take other corrective action.

Underbalanced Packer Design. If the light fill required to achieve the desired underbalance to the FCS is sufficiently large that the column is underbalanced to the pore pressure in shallower exposed sands, the operation becomes difficult to manage without at least some risk of taking a kick. This initially is not a problem because the positive surface pressure is adequate to prevent flow despite the light fluid. However, there are situations where the surface pressure may be lost while the light fill is still in the hole. For example, when a lost-returns treatment is completed, it is normal to bleed the surface pressure off and circulate with the well open. The flow can be avoided by holding backpressure until the light fill is out of the hole, but the process may be time-consuming, and there is risk that it may not be executed well. An additional complication is that it is possible to apply backpressure to the bottom of the hole with the choke only if the lost-returns treatment was successful and integrity was increased. Underbalance also may occur if surface pressure is lost because of mechanical failure of the surface equipment.

In almost all cases, the hydrostatic packer can be designed to avoid these risks, which is to say that a column of light fill can be designed to be underbalanced to the FCS in the lost zone, and yet be overbalanced to the pore pressure in other zones. The operator's practices include design checks to ensure that the well is not underbalanced to pore pressure in any phase of the operation. The following are some of these design checks.

1. Check to ensure that the light fill does not place any open zone underbalanced when the surface pressure is bled off to circulate following the treatment.
2. Check to ensure that the drillstring packer does not make the annulus underbalanced when it is circulated out. In some small-hole operations, the fluid will be taller and will cause greater reduction in head while in the annulus than in the drillstring.
3. Check to ensure the annulus hydrostatic packer will be out of the hole before the drillstring packer enters the annulus while circulating following the treatment. If both will be present in the annulus, check to ensure that the combination does not make the well underbalanced to the pore pressure.

Conclusions

Hydrostatic packers allow drillstring and annulus fluid columns to be controlled in wells that will not stand full following lost returns. Because the failure of a well to stand full affects a wide range of drilling operations, the hydrostatic packers have evolved to address a diverse range of needs. Applications described in the full-length paper include stabilizing the annulus following lost returns, controlling placement of LCM, controlling cement placement during squeeze operations, achieving high-quality cement coverage behind liners with lost returns, management of underground flow, and management of ballooning while tripping. Hydrostatic packers are simple in concept, but their use requires that engineering and field personnel be trained to understand fracture behavior and the manner in which it controls downhole pressures. **JPT**

Building a Well-Control Culture

The development of competent personnel capable of recognizing, avoiding, and mitigating well-control situations requires industry-developed systems capable of establishing necessary training standards and quality-assurance programs that monitor training-provider performance, both essential elements for ensuring proper skills development through fit-for-purpose training. The well-control accreditation program (WellCAP) operated by the International Association of Drilling Contractors (IADC) is designed to provide the drilling industry with the building blocks for a comprehensive "well-control culture" beginning at the floor-hand level and continuing to the most-seasoned drilling personnel.

Introduction

WellCAP was the first industry-developed training standard and training-provider accreditation program for drilling well control. When implemented in the mid-1990s, it broke new ground with a "core curriculum" for well-control training along with procedures and criteria for evaluating multiple facets of the operations of a training provider, from facilities and equipment to testing practices and instructor qualifications. It also introduced a new role for IADC as a group charged with monitoring and auditing training-provider performance to ensure adherence to its standards. Since the original implementation, these elements have evolved continuously to improve training effectiveness and the strength of the program.

Originally released with only a core curriculum for drilling, the program now also addresses workover and completion; coiled tubing (CT), snubbing, and wireline operations; underbalanced operations; and managed-pressure drilling. The system has been accepted by operators, contractors, and service companies, and it has been adopted as the internal standard for major oil companies and drilling contractors.

Nearly 90 training providers currently are accredited by IADC, with more than 125,000 WellCAP certificates issued since the program started (in recent years, the program has averaged more than 25,000 certificates per year). Instruction currently is given in 12 languages.

Program Evolution

The curriculum offerings have evolved steadily since the program was first implemented in 1995. Originally released with only a core curriculum for drilling, workover and completion were added in 1997. Basic well servicing was addressed with the development of curriculum for CT, snubbing, and wireline operations in 2001. Also that year, IADC developed the industry's only well-control curriculum for underbalanced operations.

While the number of levels of instruction and types of curriculum available to providers may seem daunting, the system is designed to allow both commercial providers and in-house training departments the ability to tailor their training to best meet the needs of their customers or organizations.

The Introductory Level of the software is recommended for derrick men and floor hands. The candidate must pass a basic course in well-control principles, practices, and equipment. The certification is valid for 5 years. This option is designed to allow training providers a high degree of flexibility in delivering the instruction. Simulator exercises are optional at the Introductory Level. Contractors who choose to deliver this level of training at the rigsite may be accredited to do so.

The Fundamental Level is recommended for the driller and assistant driller. The certification is provided in two options, surface or subsea stack, and is valid for 2 years. The Fundamental Level requires simulator exercises and testing to show proficiency at prevention, monitoring, kick detection, and shut-in; ability to record standpipe pressure at slow pump rate; and ability to read, record, and report drillpipe and casing pressures.

The Supervisory Level is designed for the representative on the rig (company man), mud engineer, rig superintendent, and toolpusher. The certification is granted when an individual successfully completes a course in well-control principles, practices, and equipment. This carries the same requirements, validity, and options as those at the Fundamental Level. However, simulator exercises to be provided at this level include demonstrating bringing pump on and off line and changing pump speed using choke, determining correct initial circulating pressure, and maintaining constant bottomhole circulating pressure. Subsea instruction also must include exercises to show the ability to adjust circulating pressures to compensate for choke-line friction and the ability to adjust choke to compensate for rapid change in hydrostatic pressure.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper IADC/SPE 112736, "Building a Well Control Culture With WellCAP," by ***S.M. Kropla,*** *IADC;* ***O.A. Kelly,*** *SPE,* ***T. Gillis,*** *and* ***P. Sonnemann,*** *Chevron;* ***J.J. Metcalf,*** *SPE, Newfield Exploration;* ***O.L.A. Santos,*** *SPE, Petrobras; and* ***R. Rodrigues,*** *Transocean, originally prepared for the 2008 IADC/SPE Drilling Conference, Orlando, Florida, 4–6 March. The paper has not been peer reviewed.*

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

WellCAP Plus

WellCAP Plus is an alternative to the standard Supervisory-Level training, designed to provide a higher-level skill set for well control and more-challenging learning experiences. The advanced software is intended to supplement the existing Supervisory-Level program by providing a program designed to promote a discovery process to improve critical thinking and problem-solving skills. The course is intended primarily for managers, company men, engineers, and rig supervisors who have attended several typical well-control supervisory courses and are seeking a unique learning experience to challenge their well-control skills at a higher level. The suggested minimum level for participation is driller, and all participants must be able to provide evidence of possessing at least two prior Supervisory Level certificates, one of which must be current. Whether to waive the requirement for a current certificate currently is under consideration as a possible modification to this program; if implemented, it may be done so on a temporary basis initially.

One of the greatest attributes of the advanced software is the ability for training providers to custom tailor course exercises on the basis of real-world events to emphasize lessons learned in the field. While three standard course scenarios are available to providers, providers are free to develop their own to suit the needs of their organization or their customer's organization. Eventually, IADC hopes to assemble a library of exercises dealing with numerous types of well-control situations.

Only training providers that have a current software accreditation at the Supervisory Level are eligible to participate in the advanced program. Course facilitators will have completed an IADC-approved Facilitator Certification course. The advanced program is a voluntary program; there is no requirement for a basic-software provider to participate. The advanced program is considered a specific type of accreditation with unique requirements for application, review, renewal, record keeping, and auditing.

The Texas Engineering Extension Service is the sole entity licensed thus far to provide the advanced-software Facilitator courses. The group so far has conducted five facilitator workshops, which involved 45 different participants. Course content is flexible, yet focused on progressively difficult exercises for which participants must develop team solutions. In a departure from the traditional basic-software instruction, no exit examination is required, and participants are judged on course participation and teamwork.

Advanced-software instruction may be provided only by training providers accredited by IADC to do so using certified IADC advanced-software Facilitators. Participants receive an advanced-software certificate upon course completion.

The advanced software is not intended to replace site-specific training. Site-specific training for all stakeholders is encouraged when the anticipated characteristics and challenges of a particular well warrant additional preplanning measures and focused mitigation procedures.

US Minerals Management Service (MMS)

In August 2000, the MMS published its long-awaited final Subpart O rule regarding training of workers on the outer continental shelf (OCS). As had been expected, the rule eliminated the agency's traditional prescriptive regulations in favor of a "performance-based" system.

Under the revised rules, MMS discontinued its previous practice of approving well-control training schools in the US. Instead, it made lessees responsible for developing their own training plans and for ensuring that their employees and their contractors' employees are trained adequately.

In the final rule published in the Federal Register, MMS wrote: "MMS commends IADC for the software program and acknowledges the value the program could bring in providing minimum well-control-training requirements to lessees and contractors worldwide."

While originally designed for areas outside the US and Europe where well-control standards or regulation might be minimal or nonexistent, this new approach provided an unprecedented opportunity for the software to become the industry benchmark in the US. By the time the final Subpart O rule went into effect in October 2002, members of the Operators Offshore Committee, the producer group representing active operators in the Gulf of Mexico, had accepted the software overwhelmingly. Today, the basic software is specified in the training plan of nearly every operator, drilling contractor, and service company active on the OCS.

Operator Experience

One major oil company had their cumulative blowout rate per 1,000 wells drilled drop from nearly 3.25 to 0.5, an 85% improvement. In that time period, the company experienced only two minor blowouts in drilling operations. The company marked the 10th anniversary of its program accreditation with a gala celebration at its headquarters. During those years, the company issued a total of 4,026 program certificates, with more than 1,800 of those being at the Supervisory Level.

Accreditation Process

The basic software calls for training providers to identify clearly the curriculum materials and methodology that will be used in their particular well-control training programs for specific student levels. To facilitate this, the software identifies concepts and skills elementary to well-control instruction.

The maximum class size approved for each provider is dependent on the number of well-control simulators, the number of participants per simulator group, the number of instructors, classroom space, course length, course content, and the amount of time allocated to manage simulator practice and testing.

The training program must demonstrate effective use of each of these components to ensure that the students have optimum conditions for learning the required skills. Eighteen students is generally the maximum that can attend any one course. This number may be reduced, however, depending on the resources available.

The basic program requires a minimum of 20 hours of course presentation for a drilling surface-stack course. An additional 5 hours of instruction should be included for a combined surface- and subsea-stack course (a total of 25 hours). Regardless of the curriculum type, a maximum of 9 hours of instruction (total instruction, including practical exercises) per day may not be exceeded. Under the modular approach of the basic program, additional types of instruction can be added to form combination courses tailored for the specific needs of an organization.

(Contd. on page 77)

Improving Well Safety With an Innovative Surface-Controlled Subsurface Safety Valve

A common cause of failure of surface-controlled subsurface safety valves (SCSSSVs) is a defect in the downhole hydraulic line that controls the valve from the surface. Such a failure generates production losses and requires the intervention of a costly workover rig. To alleviate this type of situation, a system has been developed in which the physical control line has been replaced by a communication system based on electromagnetic (EM) waves. The surface emitter continuously sends a signal to the SCSSSV. Both are designed to be fail-safe.

Introduction

Lacq field was developed from 1951 to 1957, while solving metallurgical constraints caused by the 15% H_2S and 10% CO_2 in its gas composition. Nearby, three other fields produce the same long and narrow reservoir and started production in late 1967. From 1968 to 1982, gas production reached approximately 33×10^6 m^3/d, the production from the four fields being centralized at the Lacq treatment plant.

These fields are now at the end of their life. The last well was drilled at the end of 1990. Since 1957, well pressures have dropped from 70 MPa to as low as 2 MPa. Unstable water production started in the early 1980s on some wells in the Meillon and Saint Faust fields, causing high operating costs because of water-disposal problems. Furthermore, the normally open velocity and ambient valves used on some wells are no longer acceptable because unstable flowing conditions do not allow accurate and repetitive closure.

To extend the life of the wells and maximize the recovery factor, Total E&P France has been looking for a solution to replace subsurface-controlled safety valves (SSCSVs) and nonfunctioning SCSSSVs with new SCSSSVs without the need for a workover. One solution is surfactant injection at the reservoir level. In this case, the challenge is to free the available nipple and set an injection device in the nipple, again without any workover or wellhead modification.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 113829, "Improving Well Safety and Maximizing Reserves Using an Innovative Surface-Controlled Subsurface Safety Valve (SC-SSSV)," by ***François Millet,*** *SPE,* ***Harvé Petit,*** *and* ***Gery Wallez,*** *Geoservices Equipment, and* ***Philippe LaLanne, Alain Ducasse,*** *and* ***Emile Barzu,*** *Total E&P France, originally prepared for the 2008 SPE Annual Technical Conference and Exhibition, Denver, 21–24 September. The paper has not been peer reviewed.*

Avoiding Workover

There currently are two types of safety systems being used.

- The SSCSVs are wireline retrievable (WR) and are calibrated well by well according to the latest production conditions. They are less and less compliant with safety regulations.
- The SCSSSVs are fail-safe, production-rate independent, and testable from the surface whether they are tubing retrievable (TR) or WR.

A TR valve is part of the tubing string that includes the control line. For the WR type, because of the large range of existing anchoring devices, including monobore lock mandrels, the physical link between the hydraulic control line and the downhole safety valve (DHSV) is a constraint that is often the source of hydraulic leaks.

Control-Line-Free Concept

It is well known that downhole tools can be controlled from the surface by use of EM waves. The new EM control-line-free concept is based on a unidirectional telemetry from surface to downhole. The surface equipment comprises a transceiver, an antenna, and low-impedance cables for connecting the wellhead and the antenna to the transceiver. The transceiver is a current generator that produces a periodic low-frequency current between a ground connection and the well. The current, going downhole along the casing and tubing, is detected by the DHSV receiver.

The current amplitude depends on the surface environment and decreases with depth because of formation attenuation. Therefore, setting depth is determined by the resistivity of the formation and by casing design, completion architecture, and cluster size. On the basis of previous experience, installations to depths as great as 150 m can be achieved easily.

Tool Design

The downhole tool has to be designed as an electrical dipole also, to detect a tension between its anchoring device and its bottom centralizer. Because hydraulic surface-controlled downhole flapper-type safety valves have proved to be reliable and cost-effective for more than 30 years, the EM SCSSSV comprises two main sections:

- A hydraulically controlled valve, integrating the flapper and its flow tube, the piston, and the return spring that guarantees mechanical closing in less than 5 seconds.
- A hydraulic power unit (HPU) placed right under the flapper comprising an electropump, a normally open electrovalve, an electronic section with a battery, and an insulated antenna

For a limited time, the full-length paper is available free to SPE members at www.spe.org/jpt.

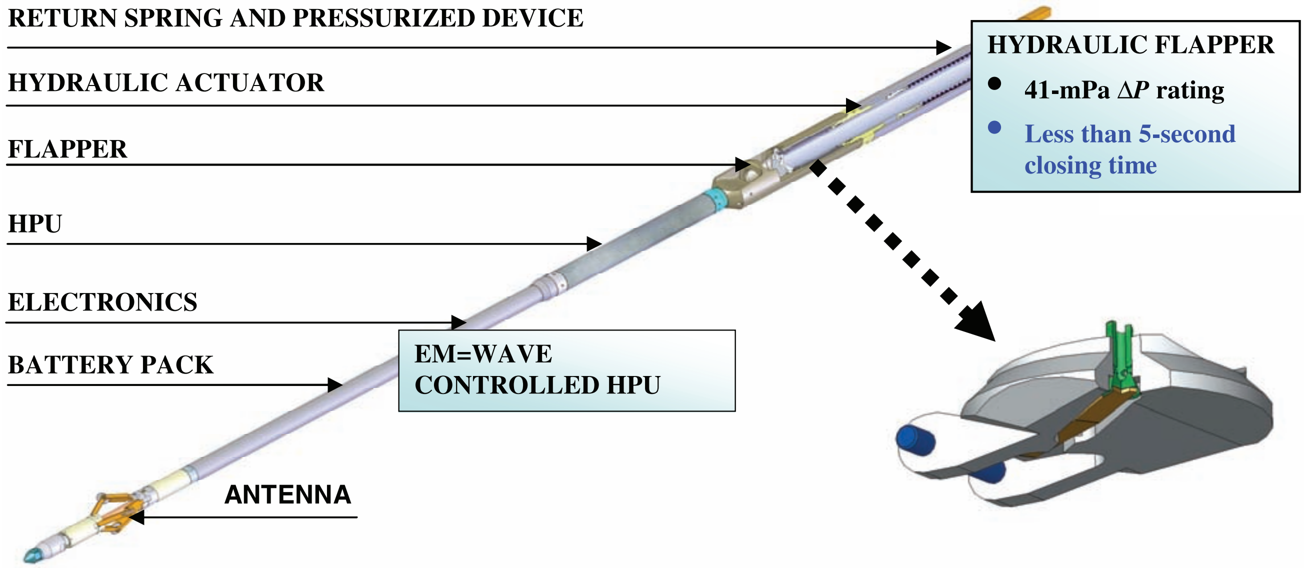

Fig. 1—Downhole equipment.

(also used as a mechanical centralizer) at its bottom.

A flapper design **(Fig. 1)** was chosen because it is the most appropriate solution for downhole safety.

Fail-Safe System

Both surface and downhole subsystems and the transmission protocol are designed to be fail-safe.

- The transceiver is managed by a built-in "watch-dog" microcontroller that is preprogrammed according to the receiver.
- The HPU is managed by a normally open electrovalve along with a built-in watch-dog preprogrammed microcontroller.
- The transceiver continuously sends a signal to the DHSV. The normally closed valve remains open while receiving the signal and closes as soon as the signal is lost.

A "radio-silence mode" is provided to avoid loss of production while perforating in a cluster when operating such a DHSV. In that mode, the valve remains open without receiving the signal for a limited period of time. If the valve does not receive the normal signal again, it closes.

Versatility

This innovative WR SCSSSV can be set in any landing-nipple profile or anywhere in the tubing by use of monobore lock technology, without workover or even wellhead modification. The HPU has been placed below the flapper to give flapper accessibility from surface by conventional slickline, like a conventional DHSV. It is common to all valve sizes and maximizes the flow rate through the valve. This modular architecture, based on proven technology, reduces both manufacturing and maintenance costs.

It is the most cost-effective solution for

- Replacing SCSSSVs and normally open velocity and ambient valves in existing completions, whatever their type or age, by a simple slickline operation.
- Freeing up an existing hydraulic-SCSSSV landing nipple to install a capillary string for chemicals, foam, or gas injection at the bottom of the well safely by setting the new safety device above the capillary-string anchor using monobore lock technology.

This safety device also allows operators to secure cluster wells while sidetracking and can reduce field insurance premiums in unsafe areas.

Case History

After a 2-year development program, in 2005 engineering built a 4-in.-outside-diameter prototype to demonstrate the feasibility and the reliability of this innovative product. At the beginning of 2006, an agreement was signed to qualify the product in situ during a 6-month period: The operator made Well LA106 available to install the valve with its own operational support including lock mandrel, slickline operations, and functional and performance tests. In addition to the prototype equipment, engineering provided associated operational procedures, technical assistance during setting operations, consumeables, and improvement management.

The first week of the field test was conducted in March 2006. The partners validated the installation procedure of the valve in a conventional landing nipple and validated the quality of reception of the EM signal downhole. Cathodic protection was activated without any effect on transmission efficiency. Some improvements were identified, and the decision was made to make these before starting the first 3-month test period.

The improved prototype was run in the hole at the beginning of July 2006. Functional- and performance-test results had convinced the partners to leave the valve downhole until the battery ran down to qualify the autonomy, computed to be 3 months. Unfortunately, after eight successful weekly functional and performance tests, a beryllium copper ring generated sufficient oxide deposit on the flow tube to lock it. The valve was no longer operational and was pulled out of the well to be changed.

Field testing restarted at the beginning of November 2007 for a calculated period of 100 days of battery autonomy. The fail-safe valve closed 98 days after setting because the battery was run down. After maintenance, the valve was reinstalled for another 3-month period and, unfortunately, was interrupted after 1$^1/_2$ months by an electrical short circuit at the electrovalve solenoid connections. After electrovalve design and manufacturing improvements, the valve was set again in Well LA106 for the second successful 3-month period.

Deployment

After 9 cumulative months in a 15%-H_2S gas well, 10 installations on landing nipples, 50 open/close cycles, and 10 leak tests, the surface and downhole equipment have proved to be easy to install, fail-safe, and reliable. With no untimely closing during that period, the robustness of the EM transmission protocol has been demonstrated, along with its compatibility with cathodic protection.

During this field-test period, engineering industrialized

- The design of two valves for 3$^1/_2$- and 4$^1/_2$-in. tubing with, respectively, 69- and 94-mm outside diameters, 33- and 51-mm inside diameters, and 0.87 and 0.99-m lengths.
- The autonomous fail-safe HPU with a 9-month autonomy and 2.1- and 2.9-m lengths, respectively, in its single- and double-battery-pack configurations.

In the near future, engineering will commercialize an offshore configuration for monopod platforms to extend this new SCSSSV range of applications. A transmission for clusters and greater water depth will be developed in a second stage.

The operator currently is starting a pilot installation on the Lacq, Meillon, and Saint Faust fields with the setting of 10 valves during 2008. Additional valves are planned for 2009. They will be set in the tubing by use of a monobore lock mandrel below the existing landing nipple, or above it after the installation of a capillary string for surfactant injection at the bottom of the well.

Conclusions

The control-line-free WR SCSSSV is a novel slickline product that is flow variation independent. It offers new possibilities for safely and efficiently managing well-completion optimization without well modification.

- In mature fields, it offers various possibilities for extending the life of the well without high capital expenditure and risks associated with a full workover.
- For new completions that also are subject to a leaking or blocked control line, it provides operators with an immediate remedial solution to continue to produce with a safety barrier while waiting for a workover rig.
- In case of sidetracking in an existing cluster, it secures producing wells during drilling operations.

In all cases, it reduces production losses and provides the user with a cost-effective and reliable solution. **JPT**

WELL CONTROL (Contd. from page 74)

The basic program was developed with an expectation of a high practical standard of testing in the well-control curriculum with regard to measuring proficiency in identified job skills. At least 50% of the identified job skills must be included specifically in the curriculum testing process. A student must score a minimum of 70% (on each of the written and simulator tests) to pass a course. One retest is allowed in the case of a failed examination, and must be administered within 45 days. Samples of the exams or tests that will be given to students must be approved by IADC. Exams must be rewritten at least once every 2 years.

Test candidates are permitted to have available a formula sheet provided by the school, blank kill sheets, reference tables, charts, and a handheld calculator. In addition, the seating arrangements to be used for written examinations must ensure the privacy of the examination paper of each candidate. Examinations are to be labeled properly to identify the testing level, and the time allowed for a test must be specified clearly at the beginning of the exam period, with reasonable means for candidates to monitor remaining time available.

The accreditation system is administered through the oversight of IADC staff, a team of highly qualified contract auditors, and a five-person panel responsible for all key decisions regarding the approval of providers, courses, and instructors. Members of the panel are volunteers representing the well-control and training groups of operators, contractors, and university faculty. The panel is nominated by the IADC Well Control Committee and approved by the IADC Executive Committee to serve 3-year terms. Procedures require a panel member to excuse himself if it appears that he may have a conflict of interest.

Once a training provider has been granted accreditation, it remains valid for 7 years, provided the training provider follows annual renewal and reporting procedures. The application process requires the training provider to do a detailed self-review of its curriculum and operations as compared to the basic-program curriculum and accreditation criteria.

A training provider is required to submit samples of its instructional materials and demonstrate its compliance with IADC criteria regarding equipment, class size, course duration, instructor experience and qualifications, student testing, and record keeping.

A site visit is required for a training provider to obtain full accreditation, even though conditional accreditation may be awarded for a brief period before a site visit is performed. Every training provider receives a site visit at least once during its 7-year accreditation. Site visits also may occur in response to complaints against a provider.

Training organizations are also feeling the pinch of increased activity. They are under growing pressure to provide skilled trainers, training programs, and training facilities. This has increased the responsibilities of IADC to monitor training providers to ensure that they are complying with program requirements. To satisfy this need, IADC has stepped up auditing efforts for all accreditation programs, but with a special emphasis on basic-program providers. **JPT**