Subsurface safety valves provide the ultimate protection against uncontrolled flow from producing oil and gas wells in case of catastrophic damage to wellhead equipment. Their use offshore is legislated in many parts of the world to protect people and the environment. Safety valves have evolved from the relatively simple downhole devices of the 1940s to complex systems that are integral components in offshore well completions worldwide.

Subsurface safety systems provide emergency, fail-safe closure to stop fluid flow from a wellbore if surface valves or the wellhead itself are damaged or inoperable. Safety valves are essential in offshore wells and in many land wells located in sensitive environments, or in wells that produce hazardous gases. They are installed to protect people, the environment, petroleum reserves and surface facilities. Successful installation, dependable operation and reliability of safety-valve systems are crucial to efficient and safe well performance.

Perhaps the most regulated component of an oil or gas well, the safety-valve system must satisfy stringent technical, quality and operational requirements. Scrutiny of safety-valve design, manufacture and operation by regulatory bodies and operators requires valve manufacturers to apply a level of diligence and testing beyond that of related well-completion and flow-control equipment. This reflects the crucial role of safety valves.

The winds and waves of Hurricane Lili impacted about 800 offshore facilities, including platforms and drilling rigs, as the Category 4 storm passed through the oil-producing region offshore Louisiana, USA, in September and October of 2002. Despite sustained winds of 145 miles/hr (233 km/hr), the US Minerals Management Service (MMS) reported that the storm caused no fatalities or injuries to offshore workers, no fires and no major pollution. Six platforms and four exploration rigs were damaged substantially by the storm. There were nine reported leaks of oil; only two exceeded one barrel. None of these spills was associated with the six severely damaged platforms.

Prevention of accidents is an important aspect of the MMS safety strategy. The lack of significant news relating to spills during this storm is a testament to the success of established safety protocols. As part of the safety system, subsurface safety valves serve a relatively unglamorous but critical role. By working properly when other systems fail, these valves are a final defense against the disaster of uncontrolled flow from a well.

In principle, a safety valve is a simple device. Most of the time it is open to allow flow of produced fluids, but in an emergency situation it automatically closes and stops that flow. To effect this task, sophisticated engineering designs and state-of-the-art materials have been developed. The valve’s closure mechanism must close and seal after months of sitting in the open position and years after its installation. Special procedures and technologies applied to reopening the valve after closure ensure its continued reliability.

Wells are drilled and completed under diverse conditions, so before an appropriate subsurface safety valve is selected and installed, a thorough review of the reservoir, wellbore and environmental conditions must be conducted.
This analysis should consider these factors throughout the predicted life of a completion, if not the life of a well. Oil and gas developments in deepwater and high-pressure, high-temperature (HPHT) reservoirs impose additional engineering challenges in the design and installation of safety valves.

In such environments, where well intervention is both difficult and costly—often exceeding several million dollars, excluding lost production—the importance of reliable safety-valve operation is even greater. This article reviews the evolution, design and installation of subsurface safety valves through examples from operations in the North Sea and Gulf of Mexico.

Disaster Drives Development
The first safety device to control subsurface flow was used in US inland waters during the mid-1940s. This Otis Engineering valve was dropped into the wellbore when a storm was imminent and acted as a check valve to shut off flow if the rate exceeded a predetermined value. A slickline unit had to be deployed to retrieve the valve.

Those first valves were deployed only as needed, when a storm was expected. The use of subsurface safety valves was minimal until the state of Louisiana passed a law in 1949 requiring an automatic shutoff device below the wellhead in every producing well in its inland waters.

Unfortunately, most disastrous situations occur unexpectedly. Surface facilities, including the safety systems, can be damaged by storms or vehicles impacting them. Boats dragging anchors or other devices can damage facilities on the bottoms of lakebeds or on the seafloor. Accidents have sometimes occurred when surface safety equipment is temporarily bypassed during logging and well-intervention operations.

The need for a new and more reliable type of subsurface safety valve was driven by accidents in Lake Maracaibo, Venezuela, in the mid-1950s. Tanker ships hitting platforms in the lake resulted in well blowouts. Producers wanted a valve that would protect the environment in case of severe damage to surface facilities, while minimizing production. The result was a surface-controlled valve that was normally closed—meaning the valve was closed unless an action kept it open. That action was fluid pressure transmitted to the valve through a hydraulic line from the surface.

A 1969 blowout in a well in the Santa Barbara Channel off California, USA, led to 1974 regulations that required the use of subsurface safety systems on all offshore platforms and installations in US federal waters. These regulations relied on requirements and recommendations set forth by an American Petroleum Institute (API) task group comprising manufacturers and users of subsurface safety valves. The API has published key guidelines for many aspects of the design and completion of oil and gas wells.

The International Organization for Standardization (ISO) revised the work of the API task group to meet global needs. These ISO standards are widely applied for international offshore projects and also for many land-based developments. In the US, the MMS enforces the requirements of federal and state legislation. Similar government bodies, such as the Health and Safety Executive in the UK and the Norwegian Petroleum Directorate in Norway, perform this function in their respective countries.

Standards and recommendations developed by various industry collaborations have led to higher safety awareness and a greater commitment to mitigate human and environmental risk. This is critically important as the industry moves to exploit petroleum reserves in operating conditions that are significantly more demanding and severe, and environmentally more sensitive than those confronted in 1974. The challenges of safe oil and gas production in deepwater and HPHT reservoirs elevate industry collaboration efforts from beneficial to essential.

Safety-Valve Operations
Modern safety valves are an integral part of systems that protect almost all offshore production installations and a growing number of land-based facilities. These systems protect people and the environment, and limit unwanted movement of produced fluids to the surface. As insurance against disaster, they must lie essentially dormant for extended periods, but be operational when needed. Development of today’s sophisticated valves occurred in distinct steps.

Early subsurface safety valves were actuated by a downhole change in production flow rate. A flow tube in such valves is equipped with a choke bean, which is a short, hard tube that restricts flow, creating a differential pressure between the top and bottom of the tube. Production fluid flowing through this choke creates a differential pressure across the bean—the pressure on the lower face of the choke bean is higher than the pressure on the upper face. When the lower face exceeds the combination of pressure on the upper face and the force of the power spring holding the valve open, the flow tube moves up and allows the flapper to hinge into the flow stream and close against a seat, sealing off flow. The flow rate to close the valve can be set during manufacture by spring and spring-spacer selection and by adjusting the hole size through the bean (above).

Safety valves that are actuated in this manner create a restriction in the wellbore that can limit production even when they are open. For many years after the introduction of safety valves in the 1940s, proration was in effect in the US market, so wells typically were produced at rates lower than their maximum deliverability. A hindrance to well-production efficiency caused by valve design and installation was not considered a serious issue at that time.
These downhole-actuated—or subsurface-controlled—safety valves have two major limitations. Since a significant variation in fluid flow or pressure is required to actuate them, these valves can be used only when normal production is restricted to a level that is less than the maximum capability of a well. This actuation level is adjusted and set before the safety valve is installed in the wellbore. Also, since a significant flow-rate change is required to actuate the shut-off, the valve will not operate in low-flow conditions in which fluid flow is less than the preset production level.

A new type of valve became necessary when energy markets changed during the 1970s, and more production was demanded from wells. However, when well productivity is maximized, it may be difficult or impossible to have enough additional flow downhole to overcome the spring force and close a subsurface-controlled safety valve. Under such conditions, reliable operation of flow-velocity type subsurface-controlled equipment can no longer be assured.

Controlling safety-valve operation from a surface control station and effecting reliable closure independent of well conditions were key objectives for design engineers. In the early 1960s, Camco, now a part of Schlumberger, introduced surface-controlled subsurface safety-valve (SCSSV) systems to meet these needs (left). Later design improvements led to an internal valve profile that creates minimal disruption to fluid flow within the production conduit while the valve is open.

An SCSSV is operated remotely through a control line that hydraulically connects the safety valve, up and through the wellhead, to an emergency shutdown system with hydraulic-pressure supply. The design is fail-safe: through the control line, hydraulic pressure is applied to keep the valve open during production. If the hydraulic pressure is lost, as would occur in a catastrophic event, the safety valve closes automatically through the action of an internal power-spring system—a normally-closed fail-safe design.

With an SCSSV, activation no longer depends on downhole flow conditions. External control also allows the valve to be tested when desired, an important improvement for a device that may be installed for years before its primary use is required.

2. The regulations use API Specifications 14A and 14B.
3. A prorated well is one in which the maximum production rate is fixed by law.
Closure systems—Early safety-valve closure mechanisms typically had two main designs: a ball- or a flapper-valve assembly (above). The ball-valve design is a sphere—the ball—with a large hole through it. When this hole is aligned with the production tubing, flow is unimpeded. Rotating the ball 90° places the solid part of the ball in the flow stream, stopping flow (top). The more common flapper valve works like a hinge with a spring. When the flow tube is down, the flapper is open, and when it is pulled up, the flapper closes (bottom).

Debris in the flow stream and solids buildup from scale or paraffin are less likely to prevent closure of a flapper valve than a ball valve. A ball valve can be damaged more easily by a dropped wireline tool or other equipment lost in the wellbore. Fluids can be pumped through flapper valves without damage to the flapper sealing surface.

The primary function of a subsurface safety valve is to close and block flow when emergency conditions require halting well production. The API has set an acceptable leakage rate of 5 scf/min [0.14 m³/min] for newly manufactured subsurface safety valves. This is considered sufficient to contain the wellbore pressure. Schlumberger valves are tested to a more stringent standard than that required by the API specifications. A valve must close against 200 and 1200 psi [1.4 and 8.3 MPa], and no more than one bubble of nitrogen can escape within 30 seconds at either test pressure differential.

After actuation—After an incident that activates a safety valve, it may be necessary to pump weighted fluids downhole to control, or kill, the well. Safety valves are usually installed above most other downhole assemblies, so a method is needed to pass kill fluids through a closed safety valve. The increased pressure provided by pumping the well-control fluids will open a flapper valve and allow fluids to pass easily through the safety-valve assembly. Once the kill-weight fluids are in place the flapper valve’s torsion spring will return it to the closed position.

When it is time to put a well back on production, the safety valve must be reopened. Typically, the positive pressure from below holds the subsurface safety valve closed. In the earliest and simplest designs, tubing pressure was applied from surface to open the valve, but delivering the pressure required may be inconvenient or impractical due to availability of equipment or time and cost constraints.
Flapper-type safety valves today include an actuation mechanism that opens the valve using a small pressure differential that does not damage the closure mechanism. Self-equalizing valves use the same actuation mechanism and also feature a mechanism to simplify equalizing pressure from above and below the closed flapper (previous page, right). When the self-equalizing valve is closed, there is a gap between the lower end of the flow tube and the flapper. A small increase in control-line pressure moves the flow tube down enough to unseat the equalizing dart, which opens a small flow path to the production tubing below the flapper. The pressure equalizes above and below the flapper, allowing the valve to open smoothly.

The self-equalization mechanisms in ball-valve designs require application of a high hydraulic pressure that may damage the more complex closure system inherent in these types of valves.

The potential drawback of a pressure-equalization system is that any mechanism or fluid path that bypasses the closure assembly presents a potential leak path that may contribute to safety-valve failure or malfunction. This potential is minimized as much as possible through rigorous designs and manufacturing methods that set high standards for accuracy, reliability and quality assurance.

In certain applications, the functionality of an internal pressure-equalizing mechanism is an essential completion-design feature. It may not be possible to equalize pressure against a closed valve by pumping fluid into the wellbore at surface. For example, on isolated or remote wells, it may be difficult and expensive to pump fluid into a wellbore when needed; the equipment may not be readily available or may be expensive to transport to the location. For these wells, a self-equalizing valve may be used to minimize the pressure required at surface.

Generally, the preferred option is to minimize use of self-equalizing systems during well design by selecting applications and operational procedures that do not require such valves.

Conveyance systems—There are two typical methods for conveying and retrieving safety valves: tubing and slickline. The method chosen for a downhole application influences valve geometry and its effect on fluid flow from the wellbore (right).

Tubing-conveyed, tubing-retrievable safety valves are designed to be an integral component of the production-tubing string and are installed during well completion with the tubulars and other downhole equipment. For surface-controlled valves, the hydraulic-control line to surface is attached directly to the safety valve and secured to the production-tubing string as it is run into the wellbore. The primary benefit of tubing-retrievable valves is that production is unhindered; the safety-valve internal diameter is essentially equivalent to that of the production tubing. The full-diameter bore also permits access to the lower wellbore with tools and instruments for flow control, well monitoring or service.

A slickline-conveyed, slickline-retrievable safety-valve assembly is placed in the wellbore after the production-tubing string and surface-wellhead equipment have been installed. It seats and locks into a special landing nipple that was placed in the production-tubing string at the desired setting depth, either as a component of the tubing string or as an integral element of the design of a tubing-conveyed safety valve. The landing nipple has a control line to surface to provide hydraulic pressure for operating the valve.

In most cases, slickline-retrievable valves are easier and less expensive to remove from the wellbore for maintenance or inspection than tubing-retrievable designs. Most tubing-retrievable valves are designed to use slickline-retrievable valves as a secondary system; if such a tubing-retrievable valve malfunctions, the slickline-retrievable valve can be installed until the next planned workover that requires tubing to be pulled. In a small percentage of completions, a slickline-conveyed valve system is used as the primary safety valve.

A slickline-retrievable SCSSV must have a pressure connection with the hydraulic-control line from surface. The landing nipple has two polished areas on either side of a hydraulic port. Sealing elements on the outside of the slickline-retrievable valve mate with these polished bores in the nipple. Once a valve is locked in place, the seals contain the hydraulic pressure and separate it from wellbore fluids.

Material selection—In a wellbore environment, where fluids can be corrosive or erosive, and have the potential to precipitate scale and organic solids, it is difficult for any downhole equipment to maintain a high degree of readiness and reliability over an extended period of time. Flow-wetted parts, which are in contact with production fluids, must be designed to resist corrosion, erosion and the buildup of precipitates or solids.

Flow-wetted surfaces of Schlumberger surface safety valves can be protected with a surface treatment of ScaleGard scale-deposition resistant coating. This is a Teflon-based product with an enhanced binder that is applied to surfaces by a spray and bake process. The 0.0013- to 0.002-mm (0.00005- to 0.00008-in.) thick coating does not interfere with the operation of completion-equipment assemblies with moving or reciprocating parts, and is slightly flexible. A ScaleGard treatment imparts the same excellent friction-reduction properties as Teflon material even under conditions of poor lubrication.
Scale, which comprises various inorganic salts that precipitate from aqueous solution, resists adhering to parts with ScaleGard protection since Teflon surfaces resist wetting by both aqueous and organic solutions. ScaleGard coatings also have excellent chemical and heat resistance. Material selection, component design and the coating of flow-wetted parts contribute to the effectiveness and dependability of subsurface safety valves.

Valve-System Integrity

In the past, safety-valve systems have malfunctioned because of failure or problems with components other than the SCSSV itself. For piston and flapper components in the device to operate properly, the control line, control fluid and surface control systems also must be designed, manufactured, installed and maintained properly.

Small amounts of debris in the hydraulic control fluid have caused safety-valve systems to malfunction. The primary protection from this reliability hazard is to provide operating personnel with the facilities and training to apply high standards for operating and maintaining a subsurface safety system throughout its life. Additional protection comes from Schlumberger control-fluid filtering systems that can be installed in surface and downhole equipment to minimize this risk. Several deepwater safety-valve designs now include this filtering system as an integral component to ensure operational integrity for the life of a well installation.

The safety-valve control fluid must function properly throughout exposure to a wide range of temperatures and pressures. The fluid must maintain viscosity, lubricity and general conditions that ensure continuous satisfactory operation of a safety valve. The closing time for a safety valve—time elapsed between initiating action at the surface controls and valve closure—depends largely on safety-valve design and setting depth, and viscosity of the control fluid. A control fluid must be matched to all anticipated operating conditions to ensure optimized performance of a safety valve.

Historically, oil-base control fluids have been used. However, the control systems used for modern well systems often are designed to vent control pressure at the seafloor to reduce operating response time. Environmentally safe, water-base control fluids were developed for this function, and they typically maintain the high performance requirements of oil-base control fluids. Synthetic fluids are now available for situations in which the operating environment exceeds the chemical and temperature capabilities of water- or oil-base fluids.

Safety valves typically undergo functional testing to API specifications at the time of manufacture; many local governmental bodies regulate and require such testing. Since operational sensitivities vary by type of valve, model and manufacturer, the specific operating manual must be consulted to establish operational procedures and constraints for a specific valve design.

Advanced safety-valve systems should be engineered to handle a valve malfunction, so safe production can resume as quickly as possible. Many regulatory bodies prohibit production without a functional safety-valve system. The well should have contingency tools in place, with modes of operation prepared to resume or continue production safely until the next scheduled major intervention or workover. For example, as a contingency, some tubing-retrievable safety-valve systems are designed to be locked open and have a slickline-retrievable safety-valve assembly inserted to use the same control system, as described above. Although the secondary valve assembly may restrict flow somewhat, production can be continued while preserving the necessary functionality for well safety.

Turbulent flow can generate material loss from tubular walls above and below a restriction or profile change in production tubulars, such as may occur with a safety valve. Heavy-wall flow couplings often are installed in the tubing above and below safety-valve assemblies to protect the string from damaging erosion at these points. Flow couplings are always recommended—in some cases required by regulation—with slickline-retrievable safety-valve assemblies, because of the greater restriction and increased turbulence created by the change in internal profile of the flow conduits.

Optimizing Flow Safely

A systems approach frequently is used to select production tubulars and completion components for oil and gas wells. This ensures that the overall performance of the assembled completion string is compatible with reservoir deliverability and that the conduit between the reservoir and surface facilities is efficient.

Bruce field, offshore Aberdeen, Scotland. On the right is a Bruce field wellbore design. The SCSSV is placed at the shallow depth of 937 ft [286 m]. Chemical-injection mandrels are much lower in the well.
Completions are designed to minimize the effects of corrosion and erosion to be expected from produced fluids and solids. Production conditions can change or may exceed expected performance such that it may be possible to produce a well at rates higher than anticipated. Production engineers then have two options if they wish to use the existing completion: constrain production according to the limitations of the original completion design; or investigate how production levels can be increased while maintaining an acceptable safety factor within the limits of installed equipment.

BP adopted the latter approach for gas wells in the Bruce field, located in the northern North Sea [previous page]. Development began in 1992, with first oil and gas produced in 1993. A study to assess the impact of production changes on safety-valve operation focused on subsea wells completed in the late 1990s with 5½-in. tubing and Camco TRM-4PE tubing-retrievable safety valves. This valve design incorporates nonelastomeric dynamic seals—made of a spring-energized filled Teflon material—and a self-equalizing system [right].

Well testing and early production data supported a rock-mechanics finding that the Bruce reservoir formation was competent and had minimal potential for sand production. Recently revised operating guidelines adopted by BP at Bruce field had identified 230 ft/sec [70 m/s] as the maximum fluid velocity for nominal solids-free gas production (sand production <0.1 lbm/MMscf [0.0016 g/m³]). On this basis, BP raised the production-velocity limit for solids-free, multiphase-flow conditions on Bruce field completions. However, several wells were rate-constrained by the 110 ft/sec [34 m/s] operating limit of installed safety valves.

BP estimated that the additional production allowed by increasing the fluid-velocity limit from 110 to 230 ft/sec on the Bruce field wells would be 15 to 20 MMscf/D [425,000 to 566,000 m³/d] for each well. Recompletion or workover to allow this increase in production was not considered feasible, so the limits on SCSSV performance and capability were re-evaluated.

Operational testing of subsurface safety valves under flowing conditions, known as gas-slam testing, is routinely performed as part of the product design-validation process, using API and ISO specifications. These standard tests are performed at relatively low flow rates—tens of feet per second.

TRM-4PE safety-valve assembly used in the Bruce field. The tubing-retrievable TRM series has a compact and simple design suitable for a wide range of completion types. The number of seals and connections incorporated within the valve assembly is minimized to reduce the risk of leakage.
For higher gas flow-rate conditions, specialized equipment is required to slam test valves and monitor valve performance. The previous Schlumberger flow-rate restriction of 110 ft/sec for operation of the TRM-4P-series safety valve was set using these conventional design tests.

Additional safety-valve slam tests were performed at the BG Technology Limited test facility at Bishop Auckland in the UK, one of only three facilities worldwide capable of performing such gas-slam tests under conditions that are as close as possible to Bruce field conditions.

The primary objective of these tests was to determine if the TRM-4P-series safety valves could be safely and reliably used at producing conditions of 230 ft/sec. Part of this process established the maximum gas-flow velocity against which the safety valve will slam closed multiple times while maintaining reliable operation and sealing to an acceptable leak rate—the specified API allowable leak rate of 5 scf/min. Reliable operation is determined by measuring repeatable and consistent valve hydraulic operating pressures. The gas-slam-testing procedure and associated instrumentation were designed to monitor performance of key safety-valve components including the flapper and seat mechanism, hydraulic system and equalizing-valve-activation mechanism.

Valve closure was tested at a series of mass flow rates with visual inspection of critical components after each test series. Initial tests at 110 ft/sec were first conducted to establish a baseline for the operating performance of the valve hydraulic system and closure mechanism. Staged increases in mass flow rate were applied (below). Precise measurements of leakage were made upon initial closure and again following five open and close cycles.

The goal was to successfully test the safety valve at 230 ft/sec. This was achieved, and additional, more aggressive flow rates were applied to establish the limit of the current valve design. Tests of 400 ft/sec [122 m/s] were successfully applied to effect closure, although the rate of 350 ft/sec [107 m/s] was deemed to be the reliable limit of operation for the standard valve components in use.

As a result of testing performed on the safety valve and the engineering study conducted on the completion system, the production-rate limit for the applicable Bruce field wells was increased from 110 to 230 ft/sec. This increase was made with the knowledge that equipment performance was assured and that any questions relating to the safety or security of the well had been successfully resolved.

After 12 months, the incremental rate benefit from each of the rate-constrained wells in the Bruce field was 9 MMscf/D [255,000 m3/d] and 400 B/D [63.6 m3/d]. In addition, the test results imply rate increases may be considered for additional completions with similar SCSSV installations.

**Valve-System Considerations**

Since the 1980s, several oil and gas companies have collaborated on a major study of SCSSV reliability, including data from valve manufacturers and operating companies with offshore interests in Brazil, Denmark, The Netherlands, Norway and the UK. The study, originally undertaken by the Foundation for Scientific and Industrial Research at the Norwegian Institute of Technology (SINTEF) and currently managed by Wellmaster, remains the largest yet undertaken into subsurface safety-valve operational experience. Conclusions of the SINTEF report from 1989 have influenced safety-valve development in the years since. These conclusions include the following findings:

- Tubing-retrievable safety valves are more reliable than slickline-retrievable valves.
- Flapper valves are more reliable than ball valves.
- Nonequalizing valves are more reliable than self-equalizing valves.
- The need for routine functional testing to identify problems should be balanced against the risk of imposing conditions or damage during testing that affect the operation or reliability of safety valves.

Advances in materials science and component design coupled with superior quality assurance in materials and construction continue to improve the reliability of safety-valve systems while meeting the stringent gas-slam testing requirements and need for large dimensions for flow of modern high-production well designs. The SINTEF and Wellmaster studies show that mean time to failure of tubing-retrievable flapper valves improved from 14 years in 1983 to more than 36 years in a 1999 study.

Technical and economic influences drive the development of technology in different ways. Current subsurface safety-valve application categories can be segmented broadly as conventional, HPHT and deepwater.

Conventional safety-valve systems are installed in predictable or known wellbore conditions and require little or no specialist engineering or materials. Operators anticipate such wells will have some form of economically viable well intervention during their life, which typically is less than that of advanced wells for which intervention is not planned or feasible. The key driver in selecting components in a conventional installation is reliability at an economic price.

Completion designs for HPHT and deepwater environments have a higher standard of reliability, with an emphasis on safe and efficient operation that optimizes production from the reservoir through the entire life of a well. These more extreme applications require proven design concepts that minimize the number of seals and connections to reduce potential leak paths, and use materials that will be unaffected by the anticipated environment and applied loads throughout the life of a valve.

Interventions are becoming more costly, even when they are planned in advance. Well-completion components must last over increasingly extended periods. The costs, complexity and hazards caused by initiation of workover operations or slickline interventions may be prohibitive on subsea wells. The engineering and quality-assurance activities for such demanding and interdependent design conditions typically require solutions to be developed on a case-by-case or project basis.

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**Table: Slam Test Results**

<table>
<thead>
<tr>
<th>Target velocity, ft/sec</th>
<th>Upstream pressure, psi</th>
<th>Upstream temperature, °C</th>
<th>Flow rate, Mscf/D</th>
<th>Measured velocity, ft/sec</th>
<th>Mass flow rate, lbm/sec</th>
<th>Leak rate at closure, scf/min*</th>
<th>Leak rate after 5 cycles, scf/min*</th>
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* The specified API allowable leak rate is 5 scf/min [0.14 m³/min]

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Engineers and designers of downhole equipment are under constant pressure to make the most of available wellbore geometry without sacrificing reliability or system value. Casing size is largely determined by drilling conditions, so engineers who design completion equipment, including safety valves, must provide the desired functionality without sacrificing available flow area in the production conduit. High-strength materials allow reduction in the wall thickness of components, although compatibility with any potentially corrosive fluids in a wellbore also must be examined.

Similarly, designing valves for HPHT installations requires a more rugged construction for load- or pressure-bearing components. Advanced material selection and component design are the key tools in resolving this problem. The innovative curved flapper closure system is one example of how creative design engineers have managed to increase the safety-valve internal diameter without increasing the external dimensions of a valve assembly (above). Safety valves with curved flappers match the internal and outside diameters of smaller casing sizes better than previously thought possible.

Setting Valves at Great Depth

The depth for placing an SCSSV is limited by the hydraulic working area required to effect closure of the valve. Today, essentially all subsurface safety valves are normally closed valves, requiring a positive force to keep them open. That force is supplied by pressure in the hydraulic-control line to surface, but the constant force that is applied is the hydrostatic pressure of the fluid in the hydraulic line. In the event of control-line leakage, the control pressure could increase if a denser fluid from the tubing annulus leaks into the control line. To ensure fail-safe operation, the closing pressure of a safety-valve spring mechanism must exceed the pressure potentially applied in either of these cases.

Camco introduced a rod-piston actuation system in 1978 that has been adopted by the industry for both tubing- and wireline-retrievable valves (above). The hydraulic area is restricted to...
the cross-sectional area of a small rod piston that operates the flow tube. In addition to dramati-
cally decreasing the effect of control-fluid hydro-
static pressure, the seal diameters are smaller, so less force is needed to overcome seal friction. Setting depths in excess of 2000 ft [609 m] true vertical depth (TVD) are possible with a rod-pis-
ton valve. With even smaller rod-piston designs, deep-set valves can be rated to work at 8000 ft [2438 m] TVD. Several mechanisms have been used to overcome this depth restriction, including balance lines and gas-spring systems.

Greater depth can also be achieved by using a gas spring—a nitrogen-charged chamber—as a balancing force that acts in conjunction with the valve power spring. This charge is preset to reflect the worst-case hydrostatic pressure in the hydraulic-control line at the valve’s installed depth, thus allowing valve-setting depths greater than 12,000 ft [3658 m] TVD. Recently, three TRC-DH safety valves were placed at depths ranging from 10,047 to 10,060 ft [3062 to 3066 m] in the Gulf of Mexico, setting an industry record.

Higher well pressures and temperatures also required changes in SCSSV seal design. Elastomeric sealing materials are susceptible to degradation at high temperature and in hostile chemical environments. Over time, the reliability and efficiency of a safety valve using elastomeric sealing may deteriorate. Camco developed the first safety valve that replaces elastomeric seals with metal-to-metal sealing systems. In recent years, this technology has been coupled with metal spring-energized filled Teflon sealing sys-
tems to meet the ever-increasing severity of safety-valve applications.

Exploiting reservoirs in deep water depends on solving technical challenges that only a few years ago were thought to be insurmountable. Kerr-McGee Oil & Gas Corp. focuses on developing high-potential core-production areas, such as the frontier deepwater environment, with a rigor-
ous approach to cost, quality and technology. Their expertise and rapid response to opportuni-
ties and challenges allow Kerr-McGee to com-
plete developments and achieve early production within aggressive time frames. The Nansen and Boomvang developments that came on stream in the first half of 2002 benefited from this approach (above).7

Located in the Gulf of Mexico about 135 miles [217 km] south of Galveston, Texas, USA, the Nansen field lies in 3678 ft [1121 m] of water.
The field is developed with a combination of subsea, wet-tree wells and dry-tree wells on the platform (for more on wet and dry trees, see “High Expectations from Deepwater Wells,” page 36). At this water depth, a deep-set safety-valve system with a nitrogen-charged spring is required. With this system, the safety valve also can be positioned below the critical area in a wellbore where formation of scale, paraffin or similar wellbore deposits could impact the operation or reliability of the valve-closure mechanism. The neighboring Boomvang field was developed in parallel using similar technologies.

Kerr-McGee had a long, successful history using Camco subsurface safety valves, including the tubing-retrievable TRC-DH series deep-set safety valve, and experience working with Schlumberger on previous projects. The company involved Schlumberger engineers in well planning and completion design for the Nansen project. The TRC-DH safety valve was used for both subsea and platform wells on the Nansen development (right).

Close cooperation between Kerr-McGee and Schlumberger engineers helped resolve challenges efficiently without impacting the critical timeline. For example, long lead times often are required for material sourcing in ambitious projects, so requirements for special materials or unusual equipment specifications were identified early. This included obtaining material for manufacturing valve components, because the relatively large diameter of safety-valve components requires material in sizes that are not always commonly available.

Kerr-McGee engineers demanded redundant features and safe operating characteristics. The TRC-DH safety-valve series was specifically developed for this type of deepwater application. The valve design incorporates a dual-piston-operated control system that provides complete operating redundancy. The gas-spring system provides substantially lower control-line pressures at greater setting depths compared with conventional valve systems. The surface control-line pressure for gas-spring valves in the Nansen installation is less than 5000 psi [34.5 MPa] at surface, compared with 10,000 psi [68.9 MPa].


7. For information about the Nansen and Boomvang development: “World’s First Truss Spurs—Nansen & Boomvang,” Supplement to Hart’s E&P and Oil and Gas Investor (Fall 2002).
that would be required for conventional valve operating systems. Using this valve series contributes significantly to reliability of the control and operating system and reduces hazards associated with extreme-pressure hydraulic systems.

Kerr-McGee selected 3½-in. TRC-DH-10-F tubing-retrievable safety valves for all three of the subsea wells tied to the Nansen development (above). The nine dry-tree wells used eight 3½-in. valves and one 4½-in. valve. Three 4½-in. valves of the same specification were selected for critical subsea completions in the neighboring Boomvang development.

The compact design of the TRC-DH safety valves provides the principal dimensions of 5.750-in. outside diameter (OD) and 2.750-in. inside diameter (ID) for the 3½-in. valves, and 7.437-in. OD with 3.688-in. ID for the 4½-in. valves. Most of the components for this safety-valve series are machined from 13 chrome high-strength stainless steel, resulting in a working pressure of 10,000 psi for both valve sizes. The valve design incorporates a nose-seal system on the flow tube. This is a spring-loaded Teflon ring that the bottom of the flow tube rests on when open, thereby preventing debris and solids from accumulating in the flapper and seat.

The completion design for all of the Nansen wells placed the safety valves at 7425-ft [2262-m] true vertical depth. At this depth, temperatures were high enough that there was minimal risk of hydrates or precipitated solids inhibiting the valve operation. Since all valves were placed at the same depth, a common gas-spring pressure was applied to the valves during manufacture. Designing the completions to be similar to one another was a key factor in realizing economic benefit and eliminating procedural problems and their associated delays.

Work on these subsea wells requires a deepwater drilling rig for well access, a costly and production-delaying process that reinforces the need for reliability in safety-valve operation. The dual operating systems incorporated in each valve are independent and fully redundant control systems. This significantly reduces the risk of having to perform a well intervention or workover operation should there be a hydraulic-control system problem within the downhole safety-valve system.

A project-management approach to the selection, manufacture and installation of the safety valve and associated system components during this multwell project allowed lessons learned to be quickly incorporated into the design process for subsequent installations. For example, during the Nansen project, minor changes in material specification, product design and installation procedures were implemented as early experience highlighted opportunities for improvement. Engineering design changes and amended procedures improved the control-line clamping system, which simplified safety-valve installation. This level of integration gives both suppliers and manufacturers a shared responsibility for safety and environmental issues that are key success indicators for projects such as the Nansen development.

To date, Kerr-McGee and Schlumberger have installed 10 safety valves, all of which are operating as designed and without failure. The successes and lessons learned at Nansen and Boomvang fields—including metallurgy, manufacture, design, operations and personnel aspects for safety-valve systems—will be carried forward to other deepwater developments in the Gulf of Mexico.

Future Challenges
The trend toward more complex reservoir development continues to present challenges for designers of safety-valve systems. Petroleum reserves today are exploited from deeper water and in harsher producing and operating conditions than ever before. In these more hostile conditions, material selection is critical for increasing equipment resistance to corrosion and material degradation over extended production periods.

An essentially unlimited setting depth could be achieved by developing subsea safety valves that incorporate solenoids to activate the valve. This would alleviate the problem of pressure contributions from the weight of fluid in the control line or leaks in that line.8

The need for compact equipment and close engineering tolerances also presents design and engineering challenges for valves placed in extreme environments. Advanced coating materials and application techniques, such as the ScaleGard coating, have been developed to enhance resistance to surface deposits on flow-wetted and selected valve components. Recent improvements in chemical-injection technology allow use of ScaleGard coating within the safety valve to prevent accumulations of production-borne contaminants and help to ensure safety-valve system reliability.

Larger safety-valve sizes will soon be needed. In some areas, for example Norway, plans for monobore completions with large-diameter production tubulars highlight the need for 9½-in. safety-valve systems. The forces resulting from pressure acting on such large component areas are far beyond those of conventionally sized equipment and present significant additional challenges to design engineers.

The success and reliability of features developed in the past are key to the development of innovative safety valves for the future. Use of electronic control equipment in advanced completion systems is increasing (see “Advances in Well and Reservoir Surveillance,” page 14). This technology has proven its reliability and functionality, providing real-time indications of production behavior. State-of-the-art equipment now delivers these real-time advantages to downhole safety systems in situations that, above all others, require rapid response. This critical component of a safety system requires focus and expertise to continue development and ensure safety and efficient operation throughout a well’s life. —MA/BA/GMG