The Pressure's On: Innovations in Gas Lift

Low-cost gas lift systems have traditionally been the preferred method of artificial lift in offshore production environments. Innovations in high-performance and high-reliability gas lift systems have increased the capabilities for enhanced production and safety in modern high-pressure deepwater and subsea installations.

Maharon Bin Jadid
PETRONAS Carigali Sdn Bhd
Kuala Lumpur, Malaysia

Arne Lyngholm
Morten Opsal
Statoil ASA
Stavanger, Norway

Adam Vasper
Thomas M. White
Rosharon, Texas, USA

Introduced in the mid 1800s, gas lift is one of the oldest artificial lift methods in the oil industry.[1] However, traditional gas lift technologies, most of which have been developed since the 1950s, do not meet all of the high-pressure, high-performance and safety needs of today's deepwater and subsea completions. These gaps are being filled by new equipment that overcomes traditional design limitations.

The new equipment is sorely needed. The world's energy demand is expected to increase nearly 1.9% annually to the year 2030.[2] At least 90% of that demand will be met by hydrocarbons, which translates into an additional 11 million bbl/d [1.7 million m^3/d] of oil by the year 2010. Taking into account an annual reservoir decline rate of 5%, the need for oil will grow to nearly 44 million bbl/d [7 million m^3/d] by 2010. This need fuels concerns about uncertain future reserves. However, many industry experts believe that 50 to 75% of the oil needed for the next 20 years will come from mature assets, and are convinced that much of the demand can be met with fit-for-purpose artificial lift technologies that increase long-term potential production capabilities.[3]

Currently, there are nearly 1,000,000 producing oil wells in the world.[4] More than 90% of these are on some form of artificial lift for enhanced production. Reservoir pressure in these wells is typically inadequate for raising oil to the surface, so operators must supplement natural reservoir drive to boost gross fluid production. Although gas lift is used in only approximately 30,000 wells, it is the most widely employed and economic artificial lift method used for mature offshore oil wells.

The gas lift process involves injecting natural gas through the tubing-casing annulus in a producing well. Injected gas creates bubbles in the produced fluid contained in the tubing, making the fluid less dense. This makes it possible for formation pressure to lift the column of fluid in the tubing and increases the amount of fluid produced from the wellbore.

Unfortunately, traditional gas lift technologies have design limitations, such as limits on the gas-injection rate for stable tubing and casing fluid flow, low maximum operating pressure and unreliable backpressure systems. These constraints prevent conventional gas lift methods from meeting the safety requirements in high-pressure operations, and preclude their use in a significant number of today's deepwater and subsea completions. Because of these limitations, many deepwater and subsea installations are not fitted with gas lift systems, but could benefit from them.

Design innovations, such as the use of venturi-flow geometry in gas lift valves, can reduce flow instabilities in tubing and casing. Coupled with high-pressure bellows systems, these improvements have significantly extended the maximum pressure limitation of gas lift systems from 2,500 psi to 5,000 psi [17.2 to 34.5 MPa]. In addition, the recent introduction of surface-controlled gas lift flow-control valves has increased the range of applications and the flexibility of gas lift systems. These new gas lift capabilities are addressing the growing needs of current and future deep wells and subsea completions.

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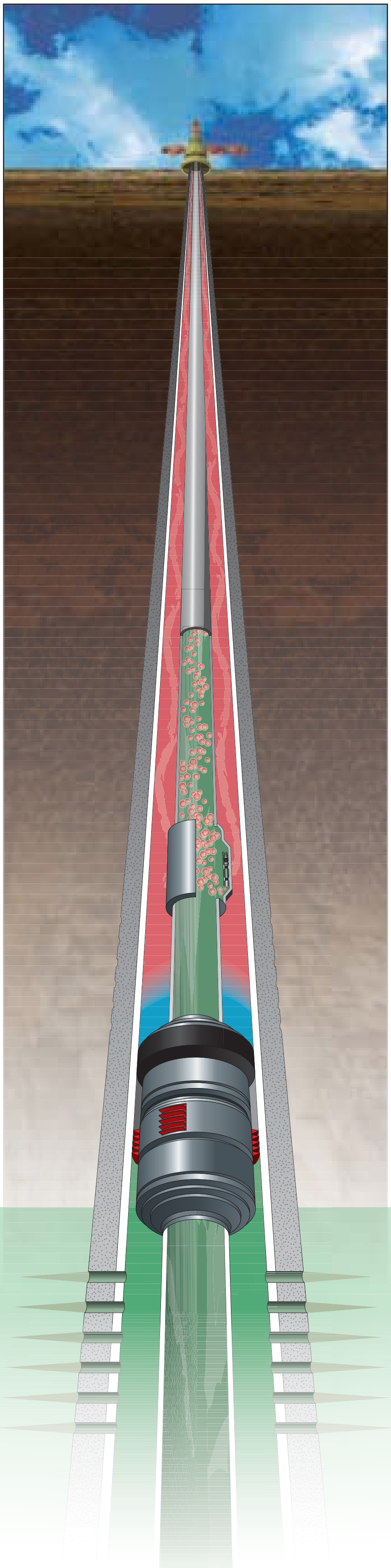
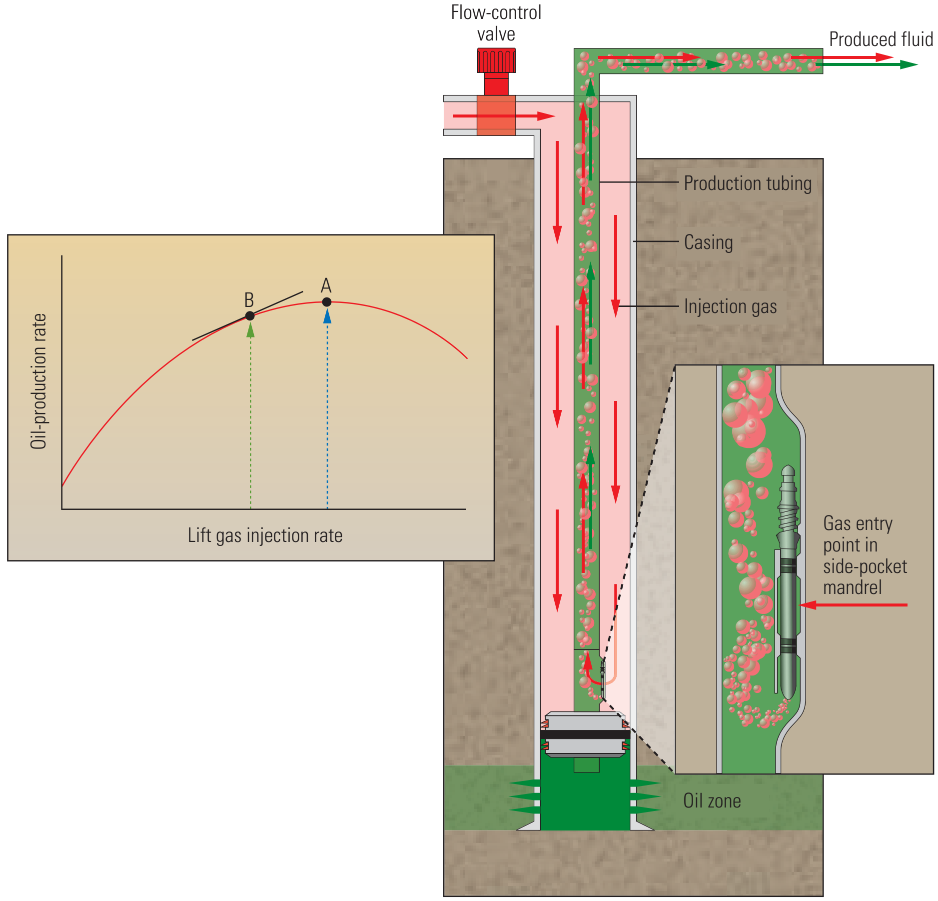
1. The first gas lift patent, the Brear Oil Injector, was issued in 1865, and more than 70 gas lift patents and applications were developed between 1865 and 1953. For more on the history of gas lift: Brown KE: *Gas Lift Theory and Practice, Including a Review of Petroleum Engineering Fundamentals.* Englewood Cliffs, New Jersey, USA: Prentice-Hall (1967): 181–197.
2. International Energy Outlook 2006, DOE/EIA-0484 (2006) published by the U.S. Government Energy Information Administration, http://eia.doe.gov/oiat/ieo/world.html (accessed November 24, 2006).
3. Pike B: "Importance of Mature Assets Development for Future Energy Supplies," keynote presentation at the Hart Energy Conference, "Brownfields: Optimizing Mature Assets," Denver, October 31–November 1, 2006.
4. Abraham K: "High Prices, Instability Keep Activity High," *World Oil* 227, no. 9 (September 2006), http://www.worldoil.com (accessed December 20, 2006).
5. Fleshman R, Harryson and Lekic O: "Artificial Lift for High-Volume Production," *Oilfield Review* 11, no. 1 (Spring 1999): 48–63.
6. Donnelly R: *Artificial Lift: Oil and Gas Production.* Austin, Texas: PETEX, 1985.





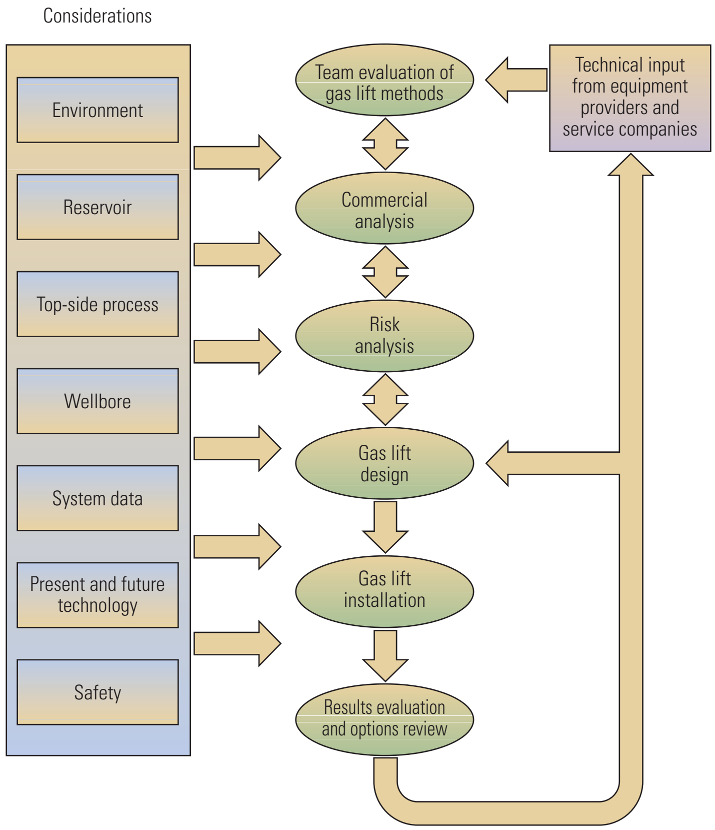
^ Gas lift. Gas lift increases oil flow by reducing the hydrostatic head of the fluid column in the well (*right*). In a gas lift well, the downhole tubing pressure is a function of the amount of gas injected, fluid properties, flow rates, and well and reservoir parameters. The oil-production rate that can be achieved from an individual well is a function of the surface gas-injection flow rate (*left inset*). Increasing the gas-injection rate will in turn increase the amount of oil produced from the well to a point where produced gas volume replaces produced oil, yielding a maximum oil production rate (A). In typical operations, the cost of gas lifting the well must be considered as part of the overall system economics. Some of the lift-cost factors include natural gas costs, gas compression and fuel costs, and nonhydrocarbon (produced water) liquid-disposal costs versus the current price for a barrel of oil. In many cases, the optimal injection rate (B) and associated oil-production rate are more economical and offer a better rate of return than the maximum injection and oil rate (A), which have a much higher lift cost per barrel.

Advanced gas lift technologies are helping operators enhance oil production and improve oil-reserve recovery. This article expands on the basic principles of gas lift and describes how innovative methods are helping operators meet critical oil-production requirements in deepwater and subsea environments. Case studies from offshore Malaysia, the Norwegian Sea and the North Sea demonstrate how these technologies are being used in a variety of producing environments.

Principles of Gas Lift

Over the producing lifetime of an oil well, the bottomhole pressure that sustains natural production will eventually drop so low that the well will either stop flowing or fail to produce at an economic oil rate. When this occurs, significant volumes of oil may be left behind. To recover this oil and improve field productivity, a number of artificial lift solutions can be implemented. They involve either pumping the oil to the surface or changing the properties of the well fluid, allowing the available reservoir pressure to produce the oil to the surface.[5]

Gas lift is an artificial lift technique that utilizes relatively high-pressure gas injected from the surface into the wellbore, typically between the casing and production tubing, through a valve placed at a strategic depth in the well (above).[6] The injected gas enters the valve and mixes with the existing fluid in the production tubing. This mixing decreases the density of the



^ Gas lift evaluation. To install an efficient gas lift system, all the factors that affect well performance must be investigated. This includes the analysis of the sensitivities (production-line pressures, formation properties and others) that will influence gas lift well performance. From these evaluations, the gas lift application engineer can assess and determine the best design installation alternative based on technical, commercial, risk and overall system factors.

liquid, allowing the bottomhole reservoir pressure to produce oil to the surface. By maintaining a constant rate of gas injection from the surface and a constant ratio of injected gas to the wellbore fluid, the well will flow oil at a constant rate.

Since gas is the energy source for a gas-lifted system and is usually injected continuously, it is necessary to have an ample supply. In the majority of cases, gas is obtained from adjacent producing gas wells and is compressed and distributed through a surface-piping network to individual oil wells. Once a gas-lifted well is producing oil or associated well fluids, the injected gas is recovered at the surface, recompressed and reinjected into the same field.

To design an optimal and efficient gas lift system, application engineers must build a system model for each well, utilizing specific software and nodal analysis techniques provided by programs like PIPESIM production system analysis software. This software tool provides an accurate representation of the production potential of individual wells in the production network. Based on the available gas-injection pressure and gas volumes provided to wells within the production network, oil rates and gas lift allocations can be computed for each well (above). By computing system-flow potential, the modeling process aids in the proper selection of downhole gas lift equipment.

This integrated-systems approach is a marriage of each producing well's oil-flow potential, or inflow performance relationship (IPR), and the production tubing flow capacity, or outflow, to the surface network of production facilities and pipelines. The entire oil-production system, which consists of individual wells tied into the surface production infrastructure, must be designed and finely tuned to allow for optimal and stable oil production from the gas lift system.

The ideal operating system for gas-lifted wells is one that allows for a continuous and stable gas-injection rate at the deepest point possible in the wellbore. A stable injection rate at a constant injection pressure will foster a stable liquid flow rate from the reservoir, minimizing the potential for undesirable pressure fluctuations at the sandface, and allowing maximum oil production with continuous gas lift.

Gas Lift Well-Flow Stability

Operating efficiency in a continuous flow gas-lifted well depends on stable production pressures and flow rates. System stability requires that the gas lift operation be properly designed so that the downhole gas lift valve is injecting gas at the calculated critical flow rate.[7]

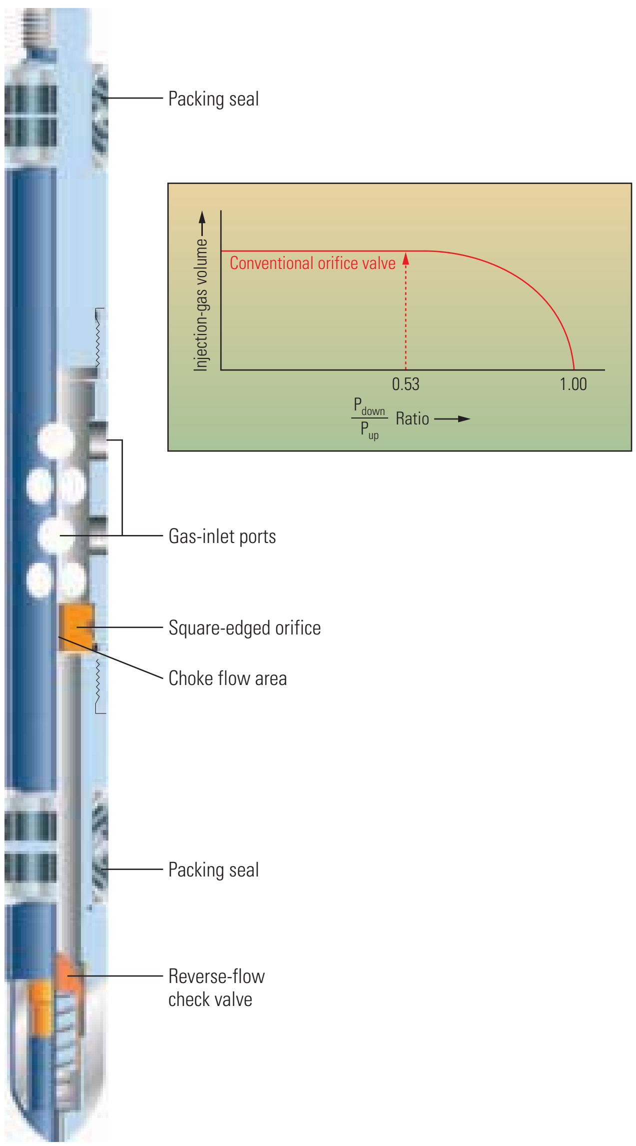
Critical flow occurs when the fluid velocity through the orifice in a gas lift valve has reached the speed of sound. The critical gas-flow rate is regulated by the upstream and downstream pressures across the gas lift valve orifice. In a conventional square-edged orifice gas lift valve design, critical flow typically occurs when there is a 40 to 60% reduction between the upstream injection pressure and the downstream flowing pressure (next page, left).

In a subcritical regime, small changes in downstream pressures tend to induce instabilities in the upstream tubing-casing annulus.[8] Small changes in pressure can cause large changes in the flow rate. In some situations, this may cause positive feedback that results in unwanted oscillations in pressure and production rates, called a "heading" phenomenon. However, at or above the critical flow rate, the feedback loop is broken, and pressure variations downstream cannot propagate back to the upstream side to call for more gas. Heading instabilities in the casing and tubing can also occur when the maximum pressure of the surface compressor system cannot sustain the differential pressure needed to maintain critical flow for adequate gas lift.

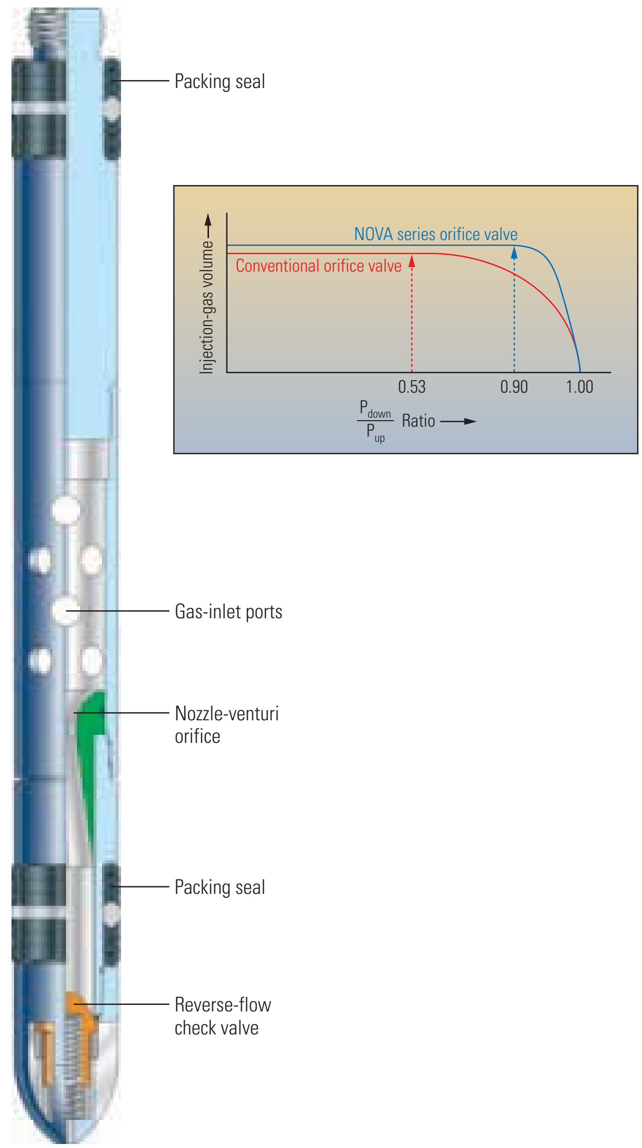
7. Alhanati FJS, Schmidt Z, Doty DR and Lagerief DD: "Continuous Gas-Lift Instability: Diagnosis, Criteria, and Solutions," paper SPE 26554, presented at the SPE Annual Technical Conference and Exhibition, Houston, October 3–6, 1993.
8. Poblano E, Camacho R and Fairuzov YV: "Stability Analysis of Continuous-Flow Gas Lift Wells," paper SPE 77732, presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, September 29–October 2, 2002.
9. Faustinelli J, Bermúdez G and Cuauro A: "A Solution to Instability Problems in Continuous Gas lift Wells Offshore Lake Maracaibo," paper SPE 53959, presented at the SPE Latin American and Caribbean Petroleum Engineering Conference, Caracas, April 21–23, 1999.
10. Tokar T, Schmidt Z and Tuckness C: "New Gas Lift Valve Design Stablizes Injection Rates: Case Studies," paper SPE 36597, presented at the SPE Annual Technical Conference and Exhibition, Denver, October 6–9, 1996.

To determine if flow instabilities are a result of the operation of the downhole gas lift system, the production engineer can use current well production-test data and gas lift operating parameters with NODAL production system modeling software to analyze the system. By modeling existing flow rates and pressures, the engineer can determine whether the gas-injection rate at the gas lift valve depth is in either critical or subcritical flow and whether a sufficient differential pressure exists between the upstream and downstream pressures to promote stable production rates.

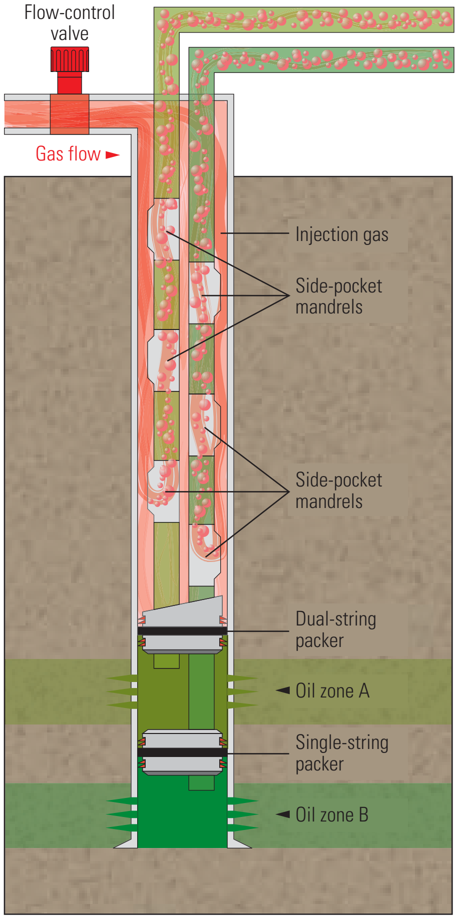
Unfortunately, the vast majority of gas lift valves contain the traditional square-edged orifice. These traditional gas lift valves are frequently installed at depths where gas-injection flow rates cannot reach critical flow velocities, giving rise to unstable oil flow. However, alternative modern gas lift technologies now can address and eliminate these flow instabilities. For example, Petróleos de Venezuela, S.A. is successfully using the Schlumberger NOVA gas lift valve to eliminate production instabilities in its Lake Maracaibo wells.[9] The innovative mechanical design of the NOVA valve's orifice uses a nozzle-venturi insert, which is a converging-diverging aperture, to control the flow of gas through the valve (below).[10] The nozzle-venturi insert causes critical gas flow to occur once the downstream



^ Conventional orifice gas lift valve and gas-flow performance plot. Gas enters the valve through inlet ports and flows through a square-edged orifice chosen to provide a controlled rate of gas flow. The flow-performance rate curve (*right*) through a conventional gas lift square-edged orifice valve can be modeled using the Thornhill-Craver equation. This equation uses the casing pressure upstream of the valve, P_{up}, and the tubing pressure downstream of the valve, P_{down}, the choke flow area, the empirical discharge coefficients and gas properties to determine the flow rate through the valve. (Adapted from Vasper, reference 13.)



^ Nozzle-venturi orifice NOVA gas lift valve and gas-flow performance plot. The performance plot (*right*) shows that critical flow (blue) is achieved through the converging-diverging aperture in the nozzle-venturi valve with a 10% pressure drop or less. By contrast, conventional square-edged orifice valves (red) require between 40% and 60% pressure drop to achieve critical flow. In most cases, it is not practical to operate with this much loss.



^ Dual gas lift completion. Dual gas lift or common-annulus dual gas lift installations are typically designed for offshore production environments. The concept allows two producing zones or two wells to be independently produced from a single wellbore. The producing zones are isolated by a dual-production packer that allows fluid production into the individual tubing strings. Gas injected into the common annulus can be independently distributed through the gas lift valves for each producing string. This concept allows an offshore operator to produce multiple zones from each wellbore, thereby doubling the number of wells that can be produced from a single offshore platform.

pressure is reduced to between 90 and 95% of the upstream pressure. In all cases, critical flow exists with differential pressures equal to 10% of the upstream pressure.

This valve is unique because it prevents flow instabilities without the attendant losses in production associated with conventional valves. Stabilization of the flowing bottomhole pressure in a well will generally increase the overall production from that well. This benefit is particularly important in dual-well completions where two independent gas lift systems are operating in a single-well annulus (above). In these gas lift installations, a single source of gas injection must be utilized to control the gas injection and flow stability of two independent producing wells. Stabilizing the injection pressure can also reduce maintenance costs.

Another benefit of the NOVA valve is the improved control it offers in gas lift fields that have computer-controlled optimization schemes.[11] Until recently, unstable wells have been excluded from controlled optimization operations because of their destabilizing effects on the feedback controls in such a system. With the NOVA gas lift valve, even if well production is slightly tubing unstable, the injected-gas rate will remain constant and, hence, injection-gas pressure, which is the control parameter for these systems, will remain stable. This makes it possible to include even more wells in optimization schemes.

Gas Lift Optimization

A recent example in Malaysia shows the benefits of switching from traditional gas lift valves to nozzle-venturi gas lift valves in a field-wide gas lift optimization campaign. The Bokor field, operated by PETRONAS Carigali Sdn Bhd (PCSB), comprises three platforms with 77 gas-lifted producing oil strings (below). Several of these strings are completed as common-annulus dual producers.

A nearby field supplies injection gas for Bokor field, and the compression facilities are on the Bokor platforms. However, with aging compressors and fluctuations in gas availability, it is critical to distribute lift gas to the most prolific producers. Key to optimizing field productivity is maintaining

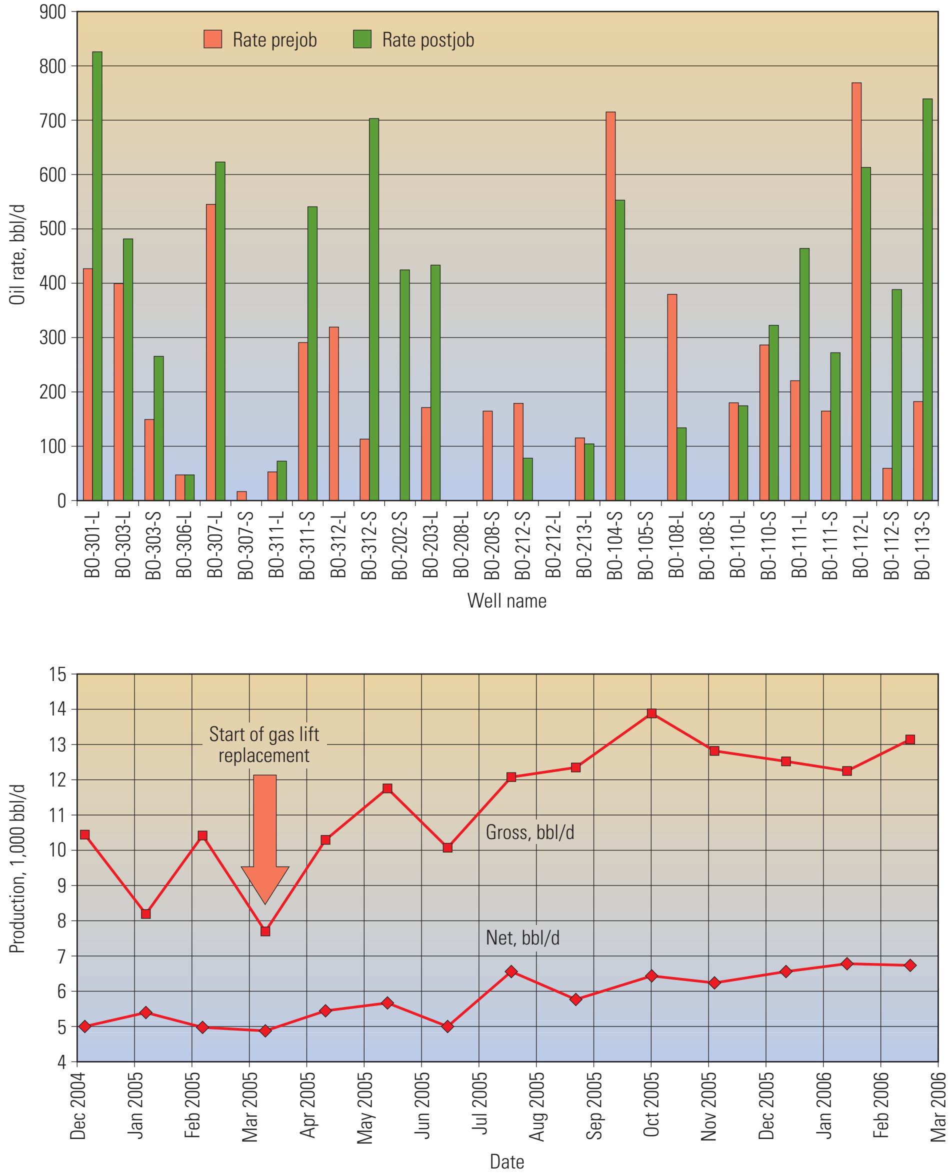
^ Bokor field. PETRONAS Carigali Sdn Bhd operates three platforms in the Bokor field located 45 km [28 mi] offshore Miri, Sarawak, East Malaysia.

lift-gas delivery to wells with unreliable gas supply, which are the ones that create significant instability in the field production.

As part of an overall production strategy for the Bokor field, PCSB and the Schlumberger Bokor alliance team implemented a gas lift system-optimization campaign to stabilize production flow rates. Well productivity would be significantly improved by minimizing the severe heading that is introduced by fluctuations in the casing gas-injection pressure and injection flow rate.

Historically, traditional square-edged orifice gas lift valves had been installed in the Bokor wells. For example, one well was originally designed for a gas-injection rate of 500 Mcf/d [14,200 m^3/d] at an injection pressure of 630 psi [4.3 MPa]. However, the production system was actually operating with a much lower injection-gas-flow rate of 120 Mcf/d [3,398 m^3/d] at a 450-psi [3.1-MPa] injection pressure, because the square-edged orifice prevented attainment of the critical gas flow rate in the well, resulting in tubing flow instabilities. By switching to a NOVA nozzle-venturi gas lift valve, the operator was able to increase the gas-injection flow rate in the well enough to reach the critical flow rate and stabilize production. The well eventually attained its originally designed gas-injection flow rate, and the average oil production increased by 80 bbl/d [12.7 m^3/d].

Over a nine-month period, the gas lift optimization campaign in the Bokor field converted all three platforms to the NOVA valve systems. Measured production readings indicated that stable injection rates and pressures were achieved in wells fitted with the NOVA gas lift valves. The gas lift optimization campaign for Bokor field increased oil productivity by more than 2,000 bbl/d [318 m^3/d] over what had been produced before the NOVA installation (right).



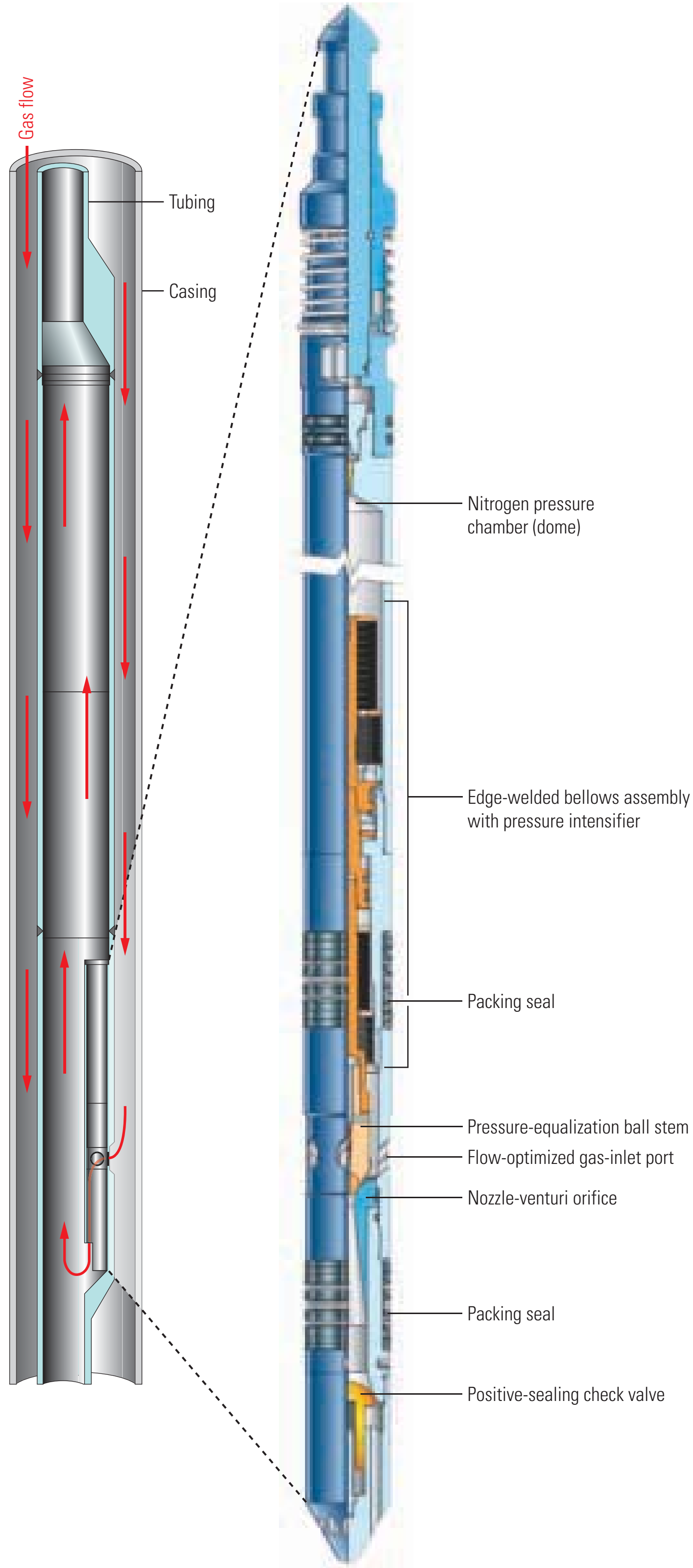
^ Bokor field gas lift optimization. Individual well performance rates are compared before and after gas lift optimization (*top*). Gross production, including oil and water, from all gas lift wells increased by approximately 60% during more than a year of operation (*bottom*). Net oil production increased by about 35%.

High-Pressure and High-Performance Gas Lift Systems

Gas lift systems have long been the preferred method of artificial lift in offshore production environments. Among the reasons for this are the relatively low cost of the initial hardware installed during the completion of the well, the general availability of gas and compression equipment, and the system's ability to adapt to changing reservoir conditions. Also, the relative ease of slickline intervention to service downhole gas lift equipment gives the operator the flexibility to change or repair the system without having to pull the entire well installation, while at the same time minimizing the amount of downtime during this intervention process. Finally, because of their relatively low cost and long-term reliability, gas lift systems are often deployed in deep subsea wells as a backup system for other artificial lift technologies, such as electrical submersible pumps (ESPs) (see "Evolving Technologies: Electrical Submersible Pumps," *page 30*).

As the number of deepwater and subsea developments continues to increase worldwide, so has the need to develop new downhole gas lift systems to maximize oil recovery. As reservoir pressures decline and water cuts increase, operators are challenged with installing systems that address the high-performance and sustained-reliability requirements of their deep operating environments, while limiting or eliminating the need for costly interventions. Also, increased pressures in deeper wells and more stringent regulatory requirements, combined with the risks associated with floating production structures, have elevated the importance of wellbore integrity in gas lift systems for subsea applications.

11. Jansen B, Dalsmo M, Nøkleberg L, Havre K, Kristiansen V and Lemetayer P: "Automatic Control of Unstable Gas Lifted Wells," paper SPE 56832, presented at the SPE Annual Technical Conference and Exhibition, Houston, October 3–6, 1999.



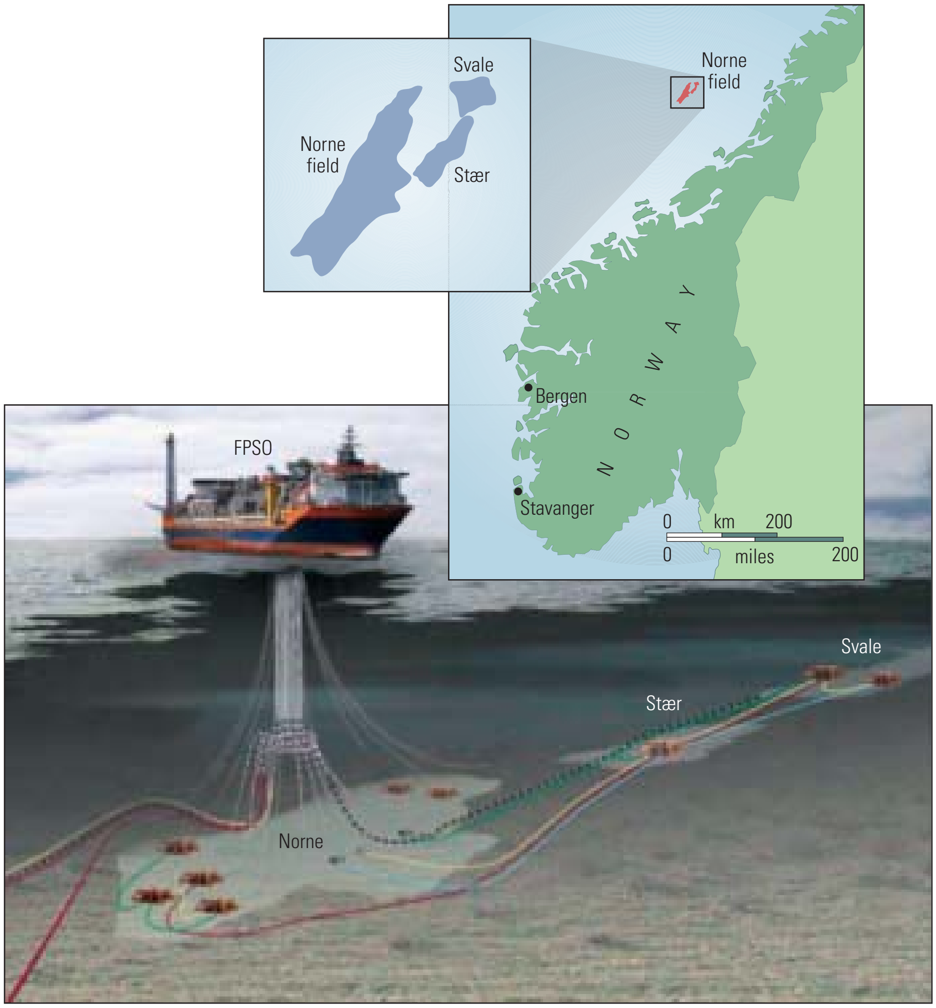
^ XLift system for deepwater and subsea applications. The XLift gas valve extends the capability of conventional gas lift systems by increasing the maximum operating pressure limit to 5,000 psi. XLift valves have a positive-sealing check-valve system that prevents potential leak paths to the tubing-casing annulus. This potential leak path is present in gas lift valves with conventional check-valve systems.

Operators considering gas lift for deepwater and subsea wells typically struggle to work within the limits of standard gas lift equipment. In most cases, this means that the greatest depth for gas injection is limited by the valve's gas-injection pressure range. In many instances, well performance analysis shows that with higher gas-injection pressures, the depth of injection could be increased significantly enough to allow the well to produce much higher volumes of oil.

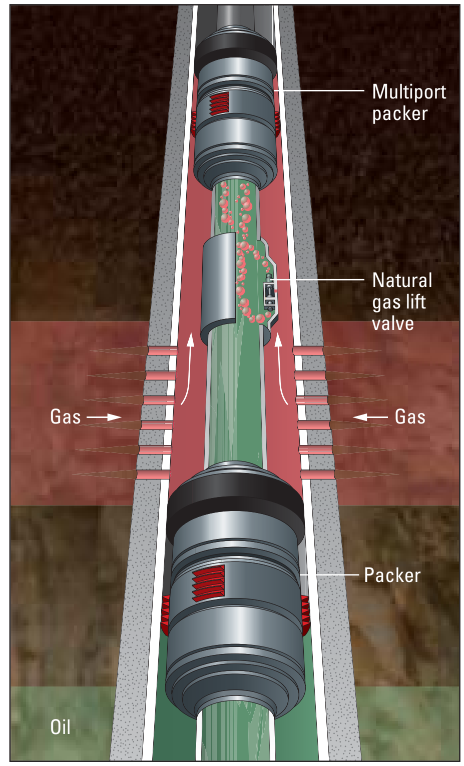
Conventional gas lift systems can operate up to a maximum injection pressure limit of 2,500 psi. This maximum operating pressure is sufficient only in traditional land-based wells and typical offshore shelf wells where reservoir depths are shallow and lower production pressures occur. However, in deeper water and subsea environments, gas lift equipment must be able to operate at gas-injection pressures up to 5,000 psi and at gas lift injection flow rates exceeding 10 MMcf/d [283,000 m^3/d]. These are nontraditional applications, and they must be accomplished while maintaining critical pressure integrity during the life of the well. Conventional gas lift valves are not capable of performing at these extreme operating levels and therefore do not offer adequate reliability. This has typically limited the use of gas lift systems in subsea wells requiring high gas-injection pressures.

The XLift high-pressure gas lift system was recently developed as a fit-for-purpose solution to address the demanding requirements of deepwater and subsea environments (left). This high-pressure gas lift system extends the capability of existing systems by increasing the operating pressure range to 2,000 psi to 5,000 psi [13.8 MPa to 34.5 MPa]. The XLift system's higher maximum injection-pressure limit allows operators to complete gas lift wells with deeper injection points to increase overall well performance.

The XLift gas lift system features a nozzle-venturi orifice flow configuration, similar to that of the NOVA gas lift valve, for more efficient and stable gas throughput. In addition, it has a positive-sealing check valve that eliminates potential leak paths to the casing-tubing annulus during nonproducing periods. The XLift valve has a patented, edge-welded bellows assembly that reduces the internal gas charge while increasing the operating pressure. A larger, 1¾-in. [4.4-cm] outside diameter valve was designed to improve the working geometry. The valve has demonstrated improved performance and reliability compared with standard gas lift valves. XLift high-pressure systems provide flexible operating ranges for multiple-well scenarios requiring high



^ Statoil's Norne floating production storage and offloading vessel (FPSO). The Norne satellite fields, Svale and Stær, and their three subsea installations are shown.



^ Natural gas lift. This technique uses gas from a subterranean formation to lift produced fluids in the well. A specialized surface-adjustable, flow-control valve is used to control the flow of injected gas. Typically, well production is optimized by setting the valve position from the surface through a small hydraulic control line.

gas-injection pressure. The development of the system components included a series of qualification flow tests to measure the effect of liquid flow erosion, and high-volume gas-flow and pressure-integrity tests to validate the reliability of the system.

XLift Operations in the Norwegian Sea

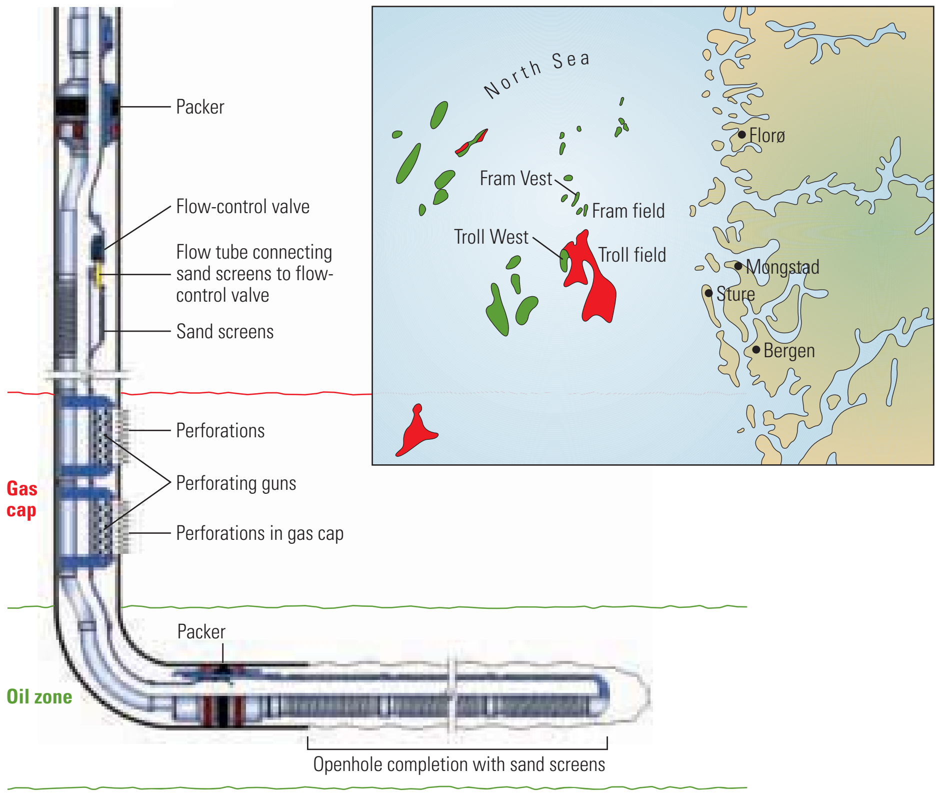
Statoil is using the XLift systems in critical subsea wells in the Norwegian Sea. For example, the Norne satellite fields Svale and Stær, located northwest of Norway, have three susbsea installations that tie back to the Norne floating production storage and offloading vessel (FPSO)(above). Within these installations there are five producing oil wells and three water-injection wells. The deepest reservoir depth is 8,150 ft [2,484 m] true vertical depth from mean sea level (MSL). The sea is about 1,245 ft [379.5 m] deep at this location. High-performance gas lift valve systems are needed in the wells to lift a high volume of produced oil and to satisfy pressure-integrity requirements. These gas lift systems require surface gas-injection pressures of approximately 3,335 psi [23 MPa] and gas-injection flow rates of 8 MMcf/d [226,500 m^3/d] to facilitate production exceeding 20,000 bbl/d [3,180 m^3/d] of oil per well.

Statoil chose the XLift system to satisfy the high-performance, reliability and environmental requirements for these subsea gas lift installations. Working with Statoil to meet rigid regulatory test requirements, Schlumberger engineers subjected the gas lift valves to a series of high-volume and dynamic, liquid- and gas-flow and pressure-integrity tests. Under Statoil's guidance, the gas-flow tests were performed at Statoil's Karsto Metering and Technology Laboratory (K-Lab), and the liquid flow tests were performed by the International Research Institute of Stavanger (IRIS). The specific objectives of the testing were to qualify the dynamic performance of the XLift valve system and to verify its use as a pressure barrier. The result of the testing and collaboration with Statoil was a valve design capable of meeting highly stringent operational criteria. XLift systems have been installed and are successfully helping to produce oil in these five Norne wells.

Natural, or Auto, Gas Lift

The introduction of surface-controlled downhole flow-control valves in 1997 led to a new technique of gas-lifting wells called natural, or auto, gas lift.[12] Natural gas lift uses gas from a downhole gas reservoir or gas cap penetrated by the same well to increase oil production through a specially designed hydraulically or electrically controlled flow-control valve with adjustable ports (above). Using gas directly from a subterranean source—rather than pumping it down the tubing-casing annulus from surface—means that a gas compressor, transportation pipelines

12. Betancourt S, Dahlberg K, Hovde Ø and Jalali Y: "Natural Gas-Lift: Theory and Practice," paper SPE 74391, presented at the SPE International Petroleum Conference and Exhibition in Mexico, Villahermosa, Mexico, February 10–12, 2002.



^ Fram Vest single-trip natural gas lift installation. Using the one-trip natural gas lift system (*left*) allows running the gas lift completion, perforating the well and setting the packers with one trip in the well. The map (*right*) shows the Norsk Hydro subsea Troll and Fram Vest fields.

and other injection-related equipment are not required for these wells. This reduces platform load requirements and capital costs for offshore facilities or subsea installations. It also has the benefit of producing gas without recompleting the well, and eliminates the need for future interventions for resizing or replacing conventional gas lift equipment.[13]

Natural gas lift requires a gas cap or a separate gas reservoir that can be completed to deliver gas at sufficient rates for gas injection. The gas reservoir must be sufficiently large that the pressure remains high enough to allow gas to be injected into tubing throughout the well's producing lifetime. The flow-control valves provided by Schlumberger for natural gas lift applications have several special features. These valves have a range of positions that can control the gas-flow rate needed to optimize production across the anticipated range of well conditions. The gas-flow rate can be adjusted from the surface—either discretely or continuously—through hydraulic or electric control of the valve opening position, which in turn enables optimized oil production. The gas rates flowing through the valves can be predicted with numerical modeling, which ensures that the valve is properly sized for the well conditions.

The valves can be opened or closed and the flow-rate position changed while subjected to significant pressure differentials, and they can withstand the erosive effects of abrasive fluids. The valves contain check valves to prevent fluid flow from the tubing to the annulus. This allows the production tubing to be pressure-tested and prevents damage to the gas-producing zone.

The use of downhole flow-control valves along with permanent-monitoring equipment also means that natural gas lift wells are considered intelligent wells. The increased value of a natural, gas-lifted, intelligently completed well is relatively easy to calculate since the costs can be compared with those of a conventional gas lift system.

Since 1998, Norsk Hydro has installed 35 natural gas lift subsea completions in 16 wells in the North Sea using Schlumberger flow-control valves. Of these, the first 31 installations have been on the Troll and Troll West fields. Norsk Hydro decided early in the development to utilize the large gas cap overlying the Troll oil rim to optimize oil recovery using natural gas lift. Using these valves for natural gas lift has helped Norsk Hydro reduce development costs by eliminating expensive surface compressors and support infrastructure for gas injection.

Single-Trip Natural Gas Lift

Following the successful installation of the first 31 natural gas lift completions in the Troll fields, Norsk Hydro presented Schlumberger with a new challenge: optimizing oil production in Norsk Hydro's marginal Fram Vest field by installing natural gas lift systems at the lowest possible cost. Gas lift in the Fram Vest field was not required for the traditional reasons of water cut or low reservoir pressure, because the production wells in this field were capable of flowing without any artificial lift. Instead, the requirement was to maximize the wellhead pressures and production in four subsea wells to flow through a 20-km [12-mi] pipeline back to the production platform.

The solution would be field-wide development optimization. The goal was to maximize oil production from each well, while maintaining similar wellhead pressures to keep the production rates of the four wells balanced. The solution for the production system also had to account for flow in long subsea flowlines. Hydro had a tight four-month schedule to complete the installations.

The customary natural gas lift installation in the Troll field required three trips in the well. The first was to perforate the well in the gas cap, another was to run sand screens on an intermediate tubing string, and a third to run the flow-control valve with the production packer and tubing to the surface.[14] This long, sequential installation process leaves the gas-cap perforations exposed for an extended time period, risking formation damage to the gas cap and posing well-control safety concerns. In addition, to minimize well-control concerns, a kill pill of heavyweight mud had to be placed in the well where the gas cap would be perforated. This in turn leads to potential reservoir damage, cleanup issues and the need to dispose of the kill pill.

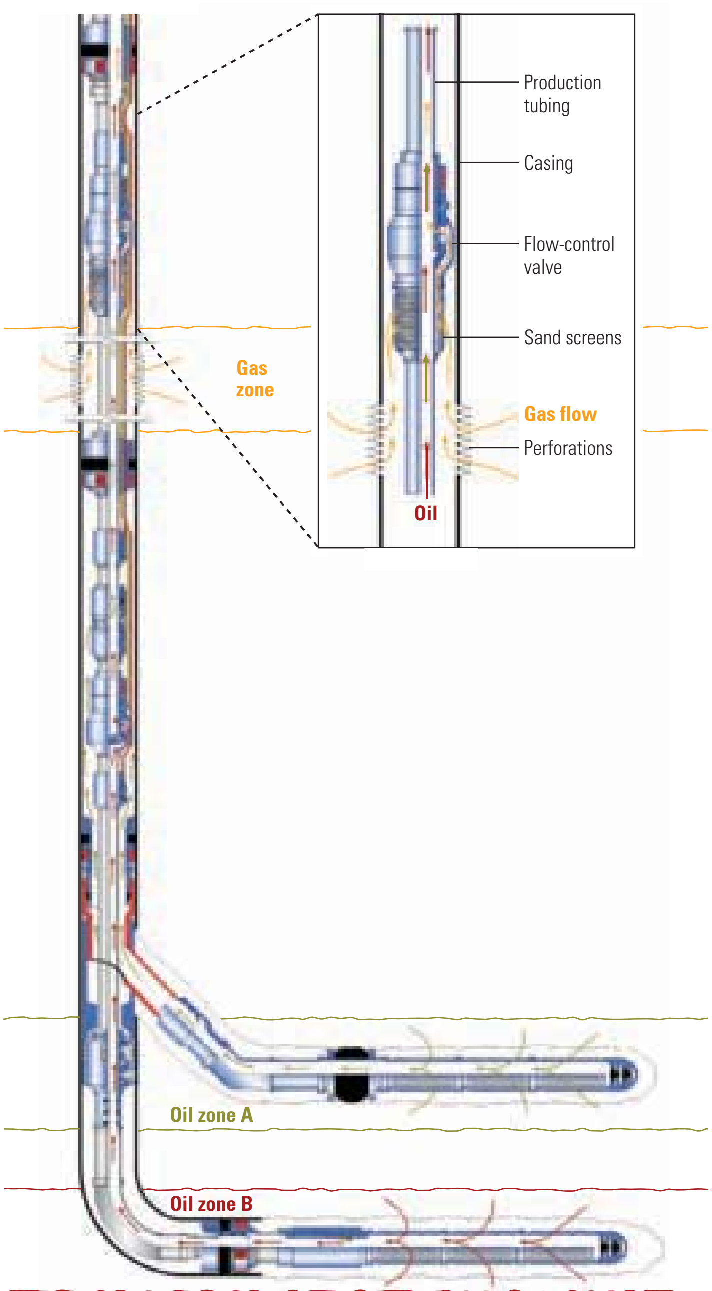
To address Norsk Hydro's goals to reduce completion costs in the Fram Vest field, protect the environment, and maximize safety and well

13. Vasper A: "Auto, Natural or In-Situ Gas-Lift Systems Explained," paper SPE 104202, presented at the SPE International Oil and Gas Conference and Exhibition, Beijing, December 5–7, 2006.
14. As a safety measure, sand screens are typically run in each oil zone and are required in all gas completions.
15. Raw I: "One Trip Natural Gas Lift Solution Brightens Picture for Marginal Oil Reserves," *Scandinavian Oil-Gas Magazine*, no. 7/8 (2004): 99–101.
16. Scott S: "Artificial Lift—Overview," *Journal of Petroleum Technology* 58, no. 5 (May 2006): 58.

productivity, Schlumberger developed a single-trip natural gas lift system (previous page). This was achieved by integrating the hydraulic gas lift valve and premium sand screens into a single tubing-conveyed assembly. Perforating guns were also installed on the outside of the completion tubing so that the entire completion could be run in one trip.

For flow control, a modified wireline-retrievable hydraulic flow-control valve allowed coupling of the gas inlet to the sand screens. When the single-installation trip was completed and the tubing hanger secured in the wellhead, pressure was applied to the annulus and then bled off to fire the tubing-mounted perforating guns. After the guns had fired, tubing pressure was applied to set the production packer.

Four systems were installed and the four Fram Vest production wells were brought on stream successfully. The single-trip natural gas lift system installations minimized risks of formation damage and well control related to the open gas-cap exposure. Compared with conventional completions in this field, the single-trip completions saved Norsk Hydro US$ 2.8 million representing two days of rig-time reduction per well. Other savings include reduced costs of completion hardware, and the elimination of the need for a kill pill and environmental disposal concerns.[15]



^ Vestflanken field dual-purpose gas lift installation. Flow-control valves control the liquid flow from each of the oil-producing legs. A third flow-control valve controls the gas used for the natural lift. Once the oil zones are depleted, the upper flow-control valve will be fully opened to allow high-volume gas production from the well.

The success of the Fram Vest single-trip natural gas lift system convinced Norsk Hydro that similar single-trip gas lift technology could be applied in many other production scenarios. For example, in three wells in their Vestflanken field, Norsk Hydro used a tubing-retrievable 11-position flow-control valve with sand screens in multilateral boreholes to allow for future gas production at high rates after the oil in these gas lift production wells is depleted (left). Schlumberger designed a surface-controlled, high-rate, flow-control valve with five choke-size positions to allow for gas lift control during the oil-production phase of the well. When the decision is made to switch to gas production, the valve will be fully opened to provide the maximum flow area required for gas production.

The Horizon for Gas Lift

Every oil well will ultimately need some form of artificial lift to help operators optimize recovery, and gas lift remains the dominant form of artificial lift in the offshore environment. In deep water, ultradeep water and other remote areas, operators are facing a broader definition of gas lift. In some of these environments, flow in long subsea tiebacks represents an important component of the production system.[16] Applying artificial lift in these situations requires technology advances to assure flow through these extended flowlines.

Furthermore, highly reliable gas lift equipment with higher pressure ratings and capabilities for deeper points of injection will be a critical component for optimizing production in these demanding environments. New high-pressure and flow-optimized gas lift technology along with surface-controlled gas lift flow-control innovations have paved the way for successful oil recovery from the world's most challenging and complex deepwater and subsea oilfields.

As operators continue to explore ways to extend the natural decline of their assets, drilling programs will continue to go deeper. Gas lift remains one of the key applications for the recovery of vast amounts of the world's oil reserves. —RH