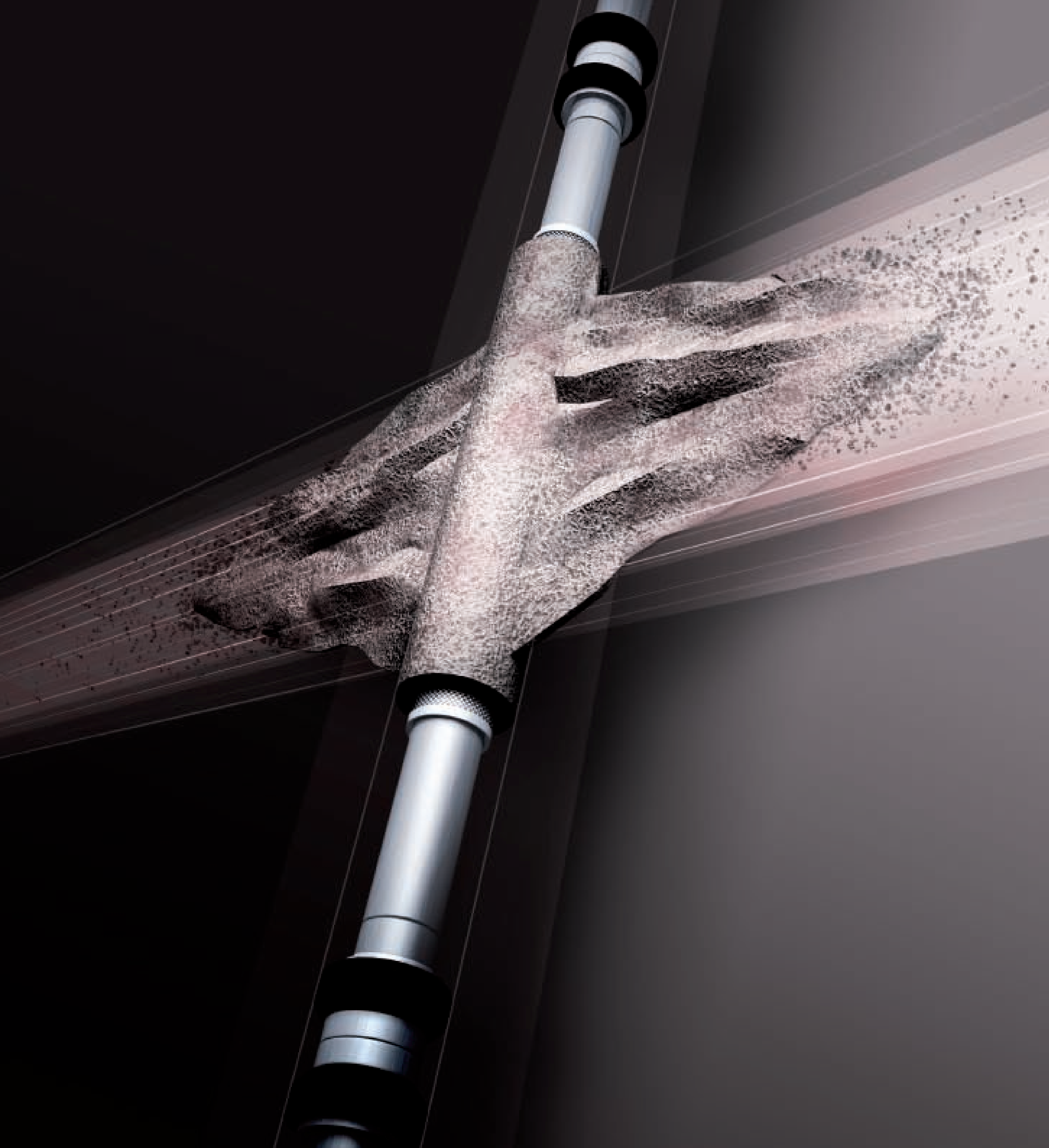


FRAC PACKING: FRACTURING FOR SAND CONTROL

Sand production damages oilfield hardware and creates downhole cavities. In addition, when solid materials reach the surface they must be separated from the fluids and then sent for environmentally approved disposal. The challenge for completions engineers is to keep loose formation solids in place without hindering well productivity.

In the past, completion methods for sand-prone reservoirs usually restricted production efficiency. New technologies have emerged to overcome this problem, and many of these are finding application in the Middle East and Asia.

In this article, Mariano Sanchez and Ray Tibbles explain how frac-pack methods can address these issues and help operators to safeguard their assets.

Hydrocarbons produced from poorly consolidated reservoirs may contain loose formation grains and other fine particles such as clays. Installing completions to control sand without sacrificing productivity, flow control, or recoverable reserves is challenging and expensive. However, the costs of subsequent treatments to alleviate damage and future remedial programs are also high—especially for deepwater and subsea wells. Operators need reliable sand control methods for wells that may be affected by these issues and the frac-pack technique provides an effective solution.

A porous and permeable sandstone formation containing large hydrocarbon volumes that flow easily into the well could be the ideal reservoir rock. However, sandstone that is so poorly consolidated that grains flow into the well with the oil or gas presents engineers with complex and potentially costly production problems. Sand produced with the oil or gas can damage vital production equipment such as valves, pipelines, and separators, which could lead to major failures. In addition, produced sand can reduce oil production and impair the performance of injection wells.

The issue of sanding is not a new one and it affects the entire industry. In the most extreme cases, several tonnes of sand may be produced from a reservoir in a single day. Such large volumes of oily sand present the additional problem of surface disposal.

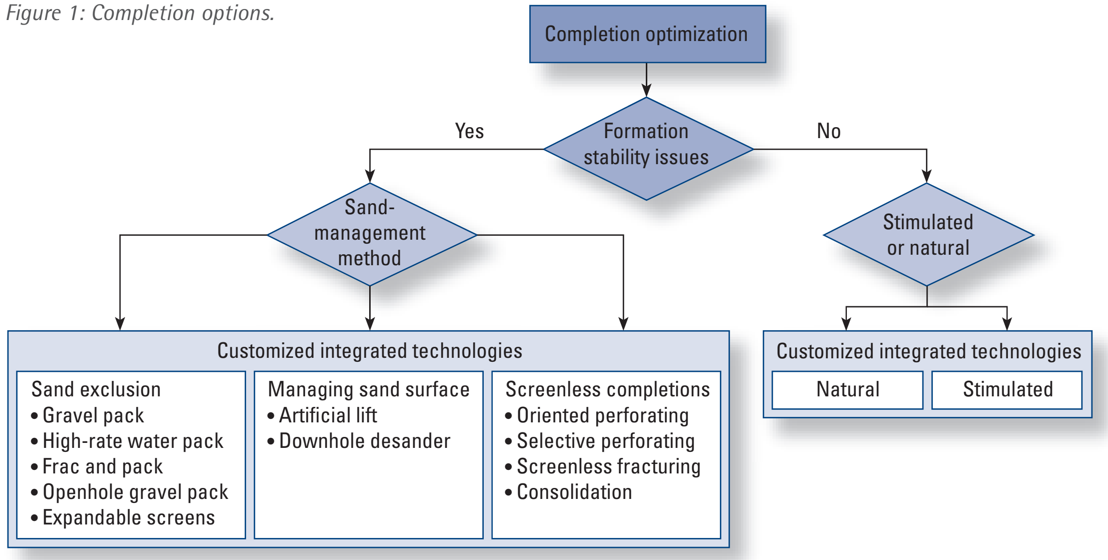
Conventional methods

When engineers know that a reservoir may be prone to sanding, they can apply sand control methods as part of the well-completion process (Fig. 1). Traditional methods, such as gravel packing and sand screens, provide a barrier to sand so that it does not enter the well with the hydrocarbons. These preventive techniques must be matched to the physical characteristics of the reservoir.

However, these conventional sand exclusion methods often reduce well productivity. Solving productivity problems began with identifying and then minimizing the source of the impairment, such as the clogging of the screens with produced sand and clay particles. In recent years, new methods for managing sand production have been introduced; for example, one of these involves sophisticated, oriented-perforating techniques that can help to prevent or eliminate produced sand during the life of a well.

For many oilfield operators, managing sand production efficiently and effectively all the time has become a vital part of their production strategies.

Figure 1: Completion options.



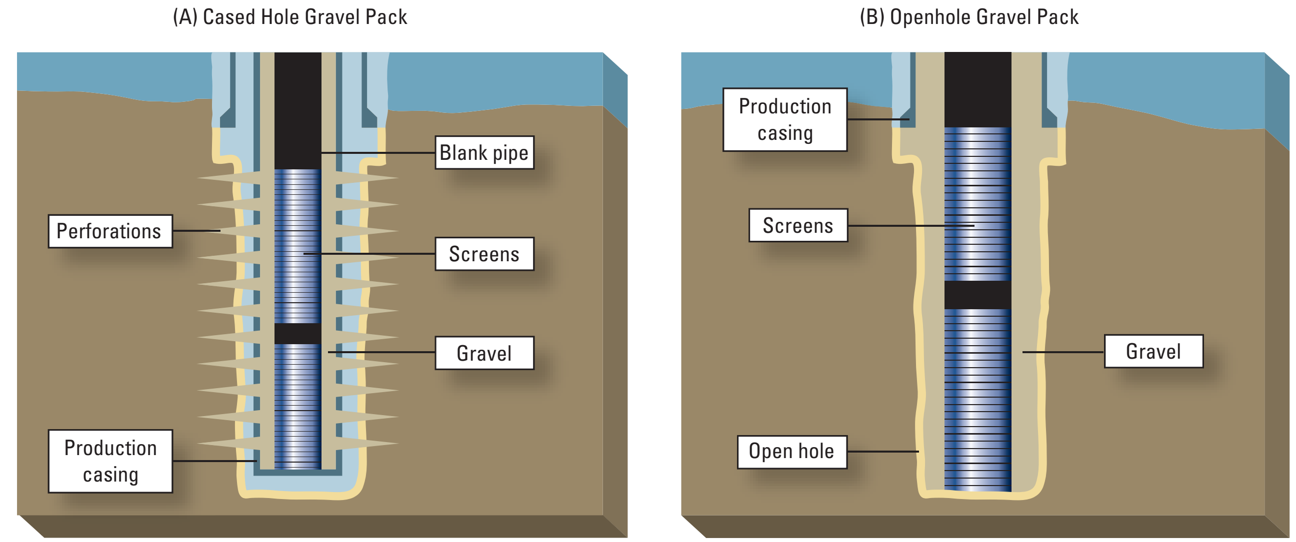


Figure 2: Gravel pack schematic showing cased hole (A) and openhole (B) options.

Gravel packing

Gravel packing is a well-established technology for sand control. In gravel-pack operations, a metal screen is placed in the wellbore and the surrounding annulus is packed with prepared gravel of a size designed to prevent the passage of formation sand. The main objective is to stabilize the formation while causing minimal impairment to well productivity (Fig. 2A).

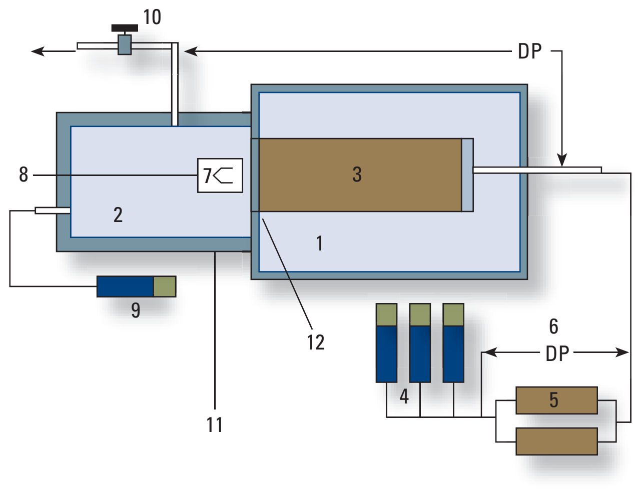
The gravel used is clean, round natural or synthetic material that is small enough to exclude formation grains and fine particles from produced fluids, but large enough to be held in place by screens. A slurry of gravel and carrier fluid is pumped into the perforations and the annulus between the screens and the perforated casing or the open hole. Gravel is deposited as the carrier fluid leaks into the formation or circulates back to surface through the screens.

In an openhole gravel pack, the screen is packed off in an openhole section with no casing or liner to support the producing formation (Fig. 2B). Openhole gravel packs are common in horizontal wells, require no perforating, and present a viable option in highly productive deepwater completions.

There are some problems, such as skin effects, associated with the gravel-pack method for sand control. The skin effect is a dimensionless factor and is calculated to determine the production efficiency of a well by comparing the actual conditions with the theoretical or ideal conditions. A positive skin value indicates that there is damage or some effect that is impairing well productivity. A negative skin value indicates enhanced productivity and typically results from stimulation.

Gravel-pack placement can lead to high positive skin values for a well. These are often due to problems in packing the perforation tunnels. Fine-grained material, produced during perforating, mixed in with the gravel can lead to a large and detrimental pressure drop between the formation and the well.

With conventional gravel-pack operations, a skin value of 10 is considered good; values around 20 are more typical. In some of the older wells found in established fields, the gravel pack can result in skin values of 40 or 50. These extreme skin effects can choke production from the well. In high-permeability wells that are poorly gravel packed, production may be reduced by more than 50%. Large skin effects can also lead to high drawdown pressures, which can cause higher gas/oil ratios and promote water coning.



1. Confining chamber with confining fluid (kerosene)
2. Simulated wellbore with wellbore fluid
3. Core sample with pore pressure and pore fluid
4. 30-galUS accumulator with predetermined gas precharge
5. Simulated reservoir rock samples
6. Differential pressure (DP) gauges
7. Gun with shaped charge
8. Shooting leads
9. 5-galUS accumulator
10. Micrometer valve
11. PCB gauges
12. Shooting plate

Figure 3: The Rosharon test setup for replicating gravel packing in a single perforation tunnel.

The search for a perfect gravel pack

In an effort to establish how these high skin values might be avoided, research scientists at the Rosharon laboratory in Texas, USA, devised an experimental program that used a soft rock core to replicate gravel packing in a single perforation tunnel (Fig. 3).

The research team explored various techniques to minimize skin values under laboratory conditions. In this controlled environment, they found that the only way to produce perforation tunnels that were completely free of crushed formation sand and perforation debris was to remove it manually: a method that is clearly not an option in the oil field. This work showed that conventional gravel-pack methods made it impossible for engineers to avoid high skin values in the field.

How frac packing works

A viable option to conventional gravel packing is frac packing. This involves the simultaneous hydraulic fracturing of a reservoir and the placement of a gravel pack. The fracture is created using a high-viscosity fluid, which is pumped at above the fracturing pressure. Screens are in place at the time of pumping. The sand control gravel is placed outside the casing/screen annulus. The aim is to achieve a high-conductivity gravel pack, which is at a sufficient distance from the wellbore, and so create a conduit for the flow of reservoir fluids at lower pressures.

The frac-pack technique combines the production improvement from hydraulic fracturing with the sand control provided by gravel packing. Creating the fracture helps to boost production rates, the gravel pack prevents formation sand from being produced, and the associated screens stop the gravel from entering the produced fluids.

This approach consistently yields sustainable production increases and has proven to be particularly effective in weakly consolidated formations, especially high-permeability reservoirs (Fig. 4). This combination of sand control and production enhancement has attracted many operators to this technique. For example, more than 65% of sand control completions in the Gulf of Mexico, USA, now use frac-pack systems.

In contrast to conventional gravel-packing methods, frac packs provide high-conductivity channels that penetrate deeply into the formation and leave clean undamaged gravel near the wellbore and in the perforations. This ensures that a much larger sandface area is in contact with the completion. In some cases, frac-pack methods may bring skin values down to zero; a wealth of published data suggests that skin values of less than 5 are common.

Frac packing avoids many of the productivity issues encountered with conventional cased hole gravel packs. The frac-pack method bypasses formation damage, or skin effects, and creates an external pack around the wellbore. This stabilizes the perforations that are not aligned with the main propped fracture.

History of the technique

The initial frac-pack projects were conducted in the Gulf of Mexico during the early 1980s. These treatments were designed and executed in a similar way to standard hard-rock-type fracturing. They resulted in longer, narrower fractures than the shorter, wider fractures of today's frac-pack treatments. The initial productivity gains from these early treatments were short-lived; therefore, the method was not widely accepted.

However, research continued, and, in the late 1980s, operators pumped the first successful tip-screenout (TSO) fracture treatment in a sandstone. These early TSO treatments placed short, wide fractures. Further advances by companies including BP and Pennzoil led to equipment and technique innovations that helped to extend the length and width of the fractures to give much higher sustained production rates than were typically seen in gravel-packed wells.

Early frac packs were pumped at about 1.6 m^3/min [10 bbl/min] with proppant concentrations up to 1.4 kg/L [12 lbm/galUS] to give total proppant quantities up to 18,000 kg [40,000 lbm]. However, industry demands for increased pump rates, higher proppant volumes, and the move to the more-abrasive ceramic proppant materials led to increased erosional forces on downhole crossover tools. Research and development by the service companies has resulted in significant technical advances and new-generation tools that can cope. Today, the industry routinely places frac packs at 8 m^3/min [50 bbl/min], with 1.4 kg/L [12 lbm/galUS] proppant concentrations and total proppant quantities in excess of 90,000 kg [200,000 lbm].

Frac packing has become an established completion technique for sand control in cased holes. Originally, the candidates selected for frac-pack operations were screened using several qualifiers to help ensure the success of a job. However, the benefits associated with NPV, reservoir management, longevity of commercial production, reduced intervention, and lower operating costs quickly became apparent to operators who used the technology. Today, many operators use frac packs as their base completion case and must have technical justification for using other sand control techniques.

Operators have found that the frac-pack technique has helped to overcome some of the issues and risks associated with formation stability and near-wellbore damage, flow assurance, water production, and water injection for pressure maintenance.

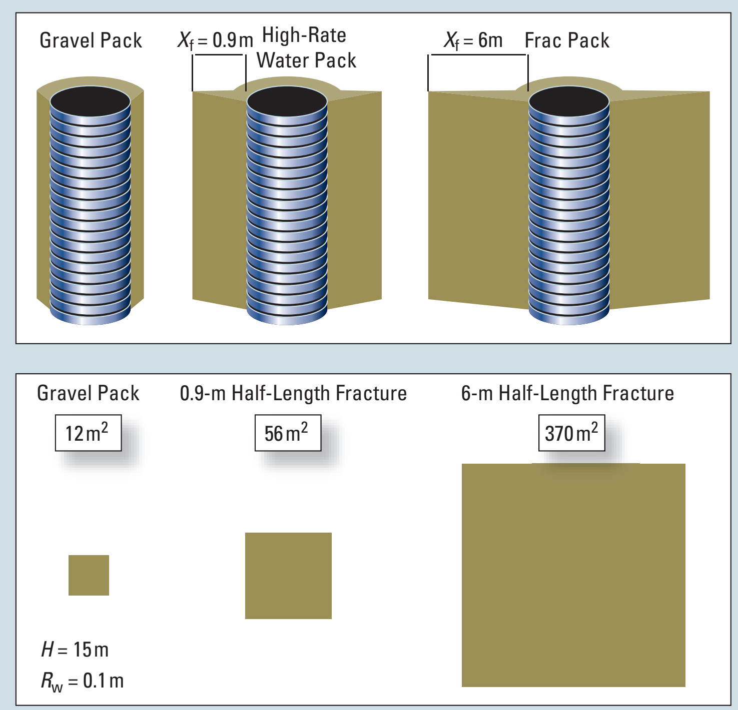


Figure 4: Relative sandface areas for gravel packing, high-rate water packing, and frac packing.

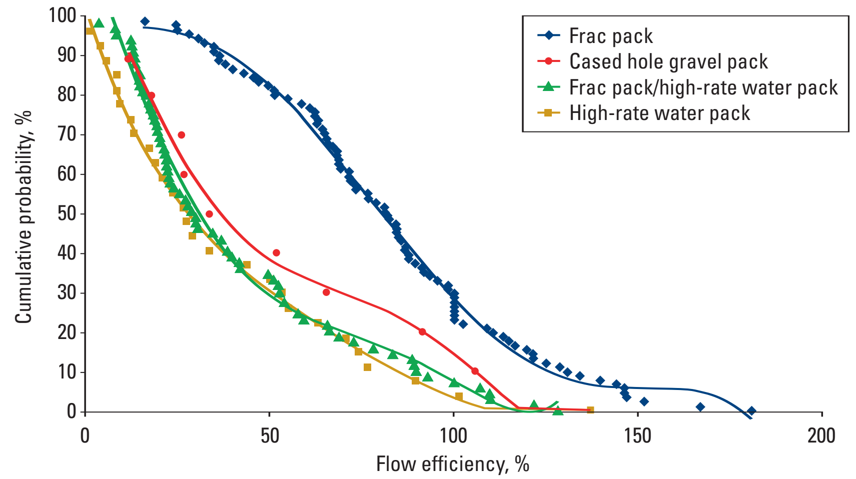


Figure 5: A comparison of the productivities achieved with different sand control methods.

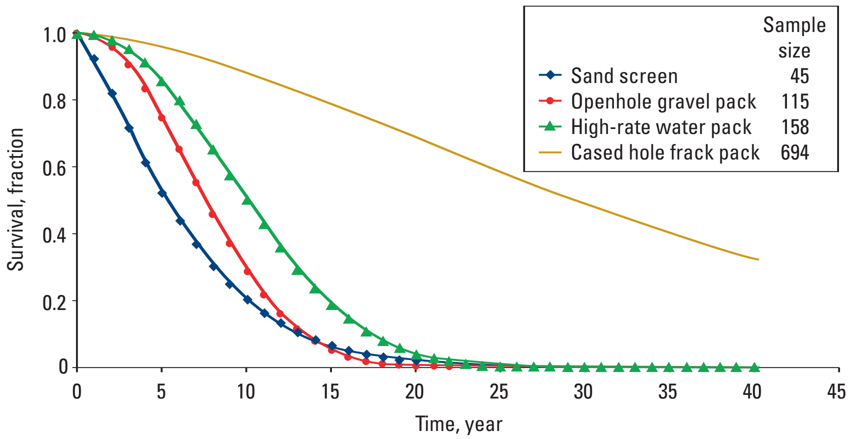


Figure 6: Completion life comparison for different sand control options.

Why frac pack?

Two of the key requirements for any completion technology are that it has a long and effective life span and that it supports high rates of production. Most of the companies that currently employ frac packing are doing so because of the lower average skin values, the high production rates, and the long-term reliability record of sand control by this type of treatment.

A review of published data for almost 200 wells shows the relative performance of various sand control completion techniques (Fig. 5). When compared with high-rate water-pack variants and cased hole gravel packing, the frac-pack method delivers consistently higher flow efficiencies.

Achieving TSO and packing the fracture with proppant are the most important elements of the technology. At every stage in the process, engineers must be certain that they have a realistic model of formation properties, and they must understand how the wellbore hardware affects placement and the measurements being made to evaluate the placement.

In addition to the productivity benefits of a properly executed job, cased hole frac packing appears to be a more stable and long-lasting solution for sand control than sand screens, openhole gravel packing, or high-rate water-packing techniques (Fig. 6). The failure rate for frac packing is about a quarter of that for cased hole gravel-pack completions and half that for high-rate water-pack completions (Fig. 7).

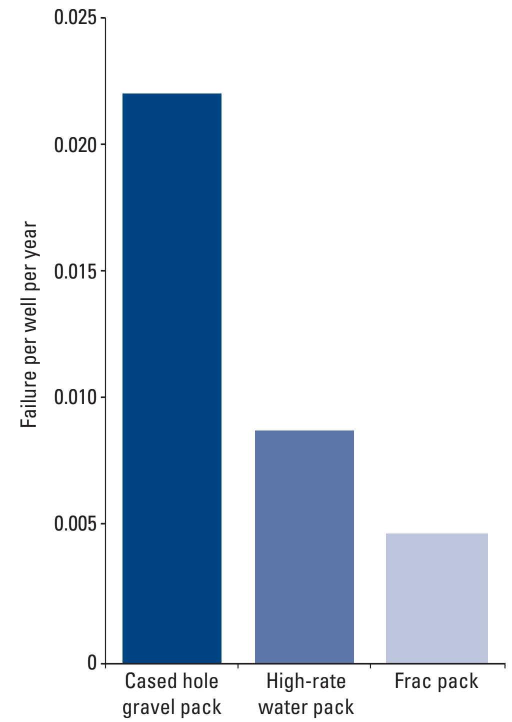


Figure 7: Completion failures.

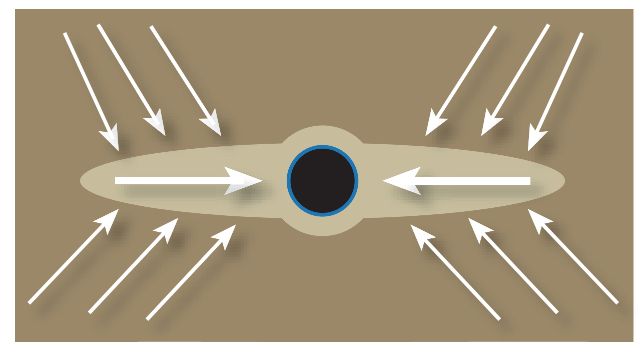


Figure 8: Fracture flow.

Planning frac-pack operations

A successful frac-pack job requires careful prejob modeling to establish the necessary fracture height and length, and professional management of the team and their equipment at the wellsite.

Prejob planning draws on a range of data sources to produce a fracturing model. Engineers will try to determine the stress profile in the pay zone and the surrounding rock layers. Because the results of the treatment hinge on producing a wide fracture, the rock mechanical properties, such as Young's modulus, are very important.

Fracture height is generally controlled by the stress field that exists within the target formation and the presence of rock barriers above and below it in the sequence. The injected fluid volumes and the fluid-loss properties of the injected fluid influence the fracture length that can be achieved.

A frac-pack job conducted in poorly consolidated sandstone produces much shorter fractures than conventional hard-rock fracturing. Typical fracture lengths are around 15–30 m; in contrast hard-rock fractures typically extend more than 150 m from the wellbore.

Schlumberger has a wealth of experience in prejob modeling. Every frac-pack job is tailored to the specific well conditions and designed to optimize well performance. Engineers use SandCADE* software to design and evaluate sand control treatments, and gravel-pack and frac-pack operations. The aim is to maximize hydrocarbon production by designing the most efficient pack. This software also helps to reduce design time as operators seek to identify the optimal treatment for their horizontal or vertical wells.

Engineers must ensure that they have verified the pressure limits for each job so that the safety standards for the field are met.

Expertise and service quality

Frac packing is not a technically demanding procedure, but, as with all oilfield operations, it is important to perform it correctly. An experienced team will pay attention to the details and ensure that the design guidelines are followed, which will result in a low-skin, high-performance completion.

There are several areas of concern associated with formation damage in a frac-pack completion. The first is in the fracture itself; the second is associated with the formation adjacent to the fracture face.

As in fracturing, one of the major issues in frac-pack completion is the extent of the conductivity retained in the fracture. The value of the frac pack is determined by the contrast in permeability between the formation and the fracture, so it is vitally important to minimize the extent of the damage, or permeability reduction, in the fracture (Fig. 8).

Even though frac packs are much more robust completions than gravel packs, it is still important that proper completion practices are followed. Material left in the wellbore as a result of drilling and cementing the well can cause serious damage to the frac pack. Because the placement of the frac-pack system involves pumping proppant-laden fluid between a screen and the casing, the scouring action of the proppant on the casing will mix any remaining material from drilling into the frac-pack fluids.

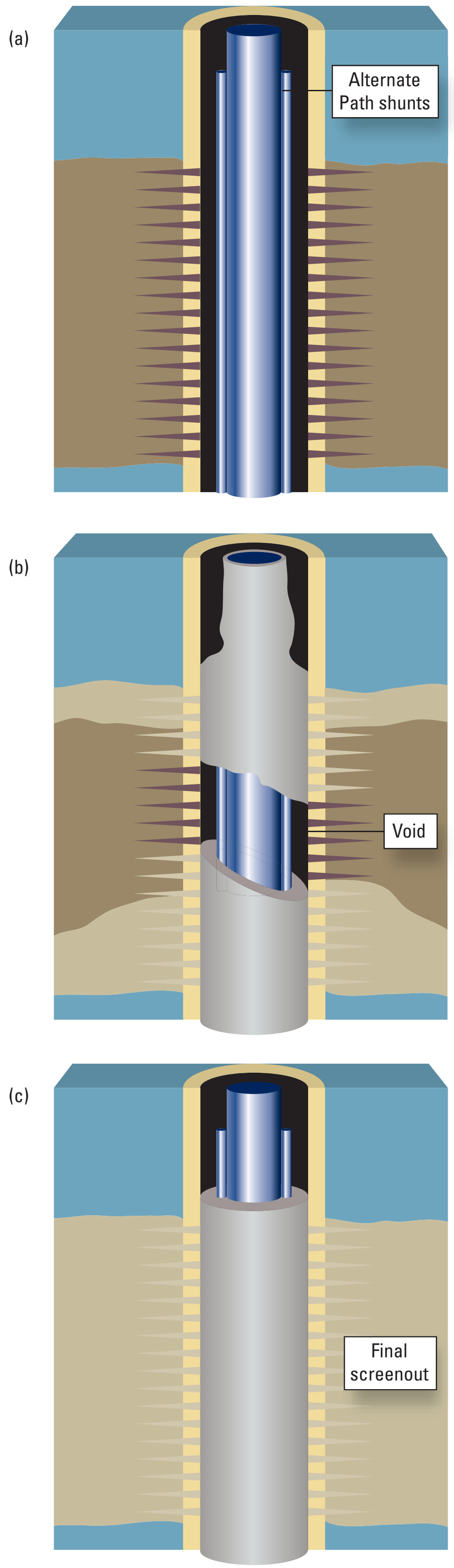


Figure 9: Alternate Path technology. (a) Gravel pack screen using external shunts. (b) Slurry placement leads to bridging and development of voids. (c) Pressure buildup after screenout forces slurry through the shunts and into the voids to ensure final screenout.

If operators remove this material, they can minimize the risk of contaminating the frac pack during placement. The effective use of a combination of chemical and mechanical cleaning of the wellbore to remove drilling mud, cement, pipe dope, scale, and rust before pumping the frac pack will greatly reduce the amount of contaminants and, therefore, enhance the final conductivity of the frac pack.

Cleaning the wellbore before placing the frac pack is, therefore, critical to the ultimate productivity of the well.

Possible limitations

Frac packing cannot be applied in all situations. It is inappropriate where the reservoir has a gas cap, and may also be unsuitable where there is no effective barrier between the reservoir zones and the underlying aquifers. However, experience in Asia, the Gulf of Mexico, and offshore West Africa suggests that even a relatively thin shale barrier (about 1 m) is sufficient for a safe frac-packing operation. Effective prejob modeling will ensure that the fractures created do not intersect water layers and cause early water production.

In some situations, a technique called high-rate water packing provides a possible alternative to frac packing. This method produces a short and relatively thin fracture using water pumped above the fracturing pressure of the formation. Pumping is carried out with the screens in place and gravel placed outside the casing-screen annulus. This method is used on completions where the risk of fracturing into a water zone is deemed unacceptable.

Alternate Path® technology

Schlumberger applies a range of innovative methods for frac-pack operations, including Alternate Path technology. This technique, used by Schlumberger under license from Exxon Mobil, is a way to optimize completion operations.

Services based on Alternate Path technology provide shunts with nozzles on the outside of the gravel-pack screen. These shunts create an alternative flow path that allows the slurry to bypass premature bridges and fill the voids below (Fig. 9). In an Alternate Path operation, gravel placement initially proceeds in the standard packing mode until screenout. Pressure buildup occurs after screenout and forces the slurry to flow through the shunts and exit through the nozzles into the first available void. Packing continues until all the voids are filled and final screenout occurs. With all the voids eliminated, the chances of gravel-pack failure are remote.

Alternate Path technology is used in the AllPAC® standard gravel-pack service; the combination of AllFRAC® and Schlumberger frac and pack services; the (multizone) MZ packer zone-isolation service; and Horizontal AllPAC and AllFRAC services for horizontal wells.

Figure 10: The location of Hiu field.

The value of the frac pack is determined by the contrast in permeability between the formation and the fracture, so it is vitally important to minimize the extent of the damage, or permeability reduction, in the fracture.

The AllPAC service

The AllPAC service applies Alternate Path technology to standard gravel-pack operations. Nozzles every 1.8 m on the shunt allow slurry to exit below a premature bridge and fill any remaining voids. In one study, AllPAC completions averaged 63 kg/m [42 lbm/ft] of gravel placed behind the casing, compared with 22 kg/m [15 lbm/ft] placed by conventional completions. The AllPAC service operates in vertical, deviated, or horizontal wells, either cased or openhole. More gravel placed means more-complete perforation packing and fewer annular voids. The result is a more reliable completion with higher production.

The AllFRAC service

Alternate Path technology is applied to frac-pack operations by using larger shunts that facilitate increased pump rates. Fractures propagate throughout the interval, not just above a premature bridge, and proppant is placed along the entire interval. The fractures are tightly packed for maximum conductivity. Multiple zones can be fractured and packed during a single run, thus saving the cost of multiple completions.

Three-zone, single-trip perforation and sand control completion

The combination of perforating and frac packing in a single trip into the well offers time and rig-cost savings when operators need sand control and low-skin completions.

In Indonesia, this approach was selected for three gas-producing sand lobes within a 195-m gross pay interval. Hiu field contains two separate field areas with three gas-bearing intervals and an estimated 198 Bcf of gas in place (Fig. 10). The lowermost interval is the lower Gabus reservoir, which includes three distinct sand lobes separated by sizeable shale sections (laminated sands) (Fig. 11). Two shallower productive intervals are present in what is called Gabus zone 3.

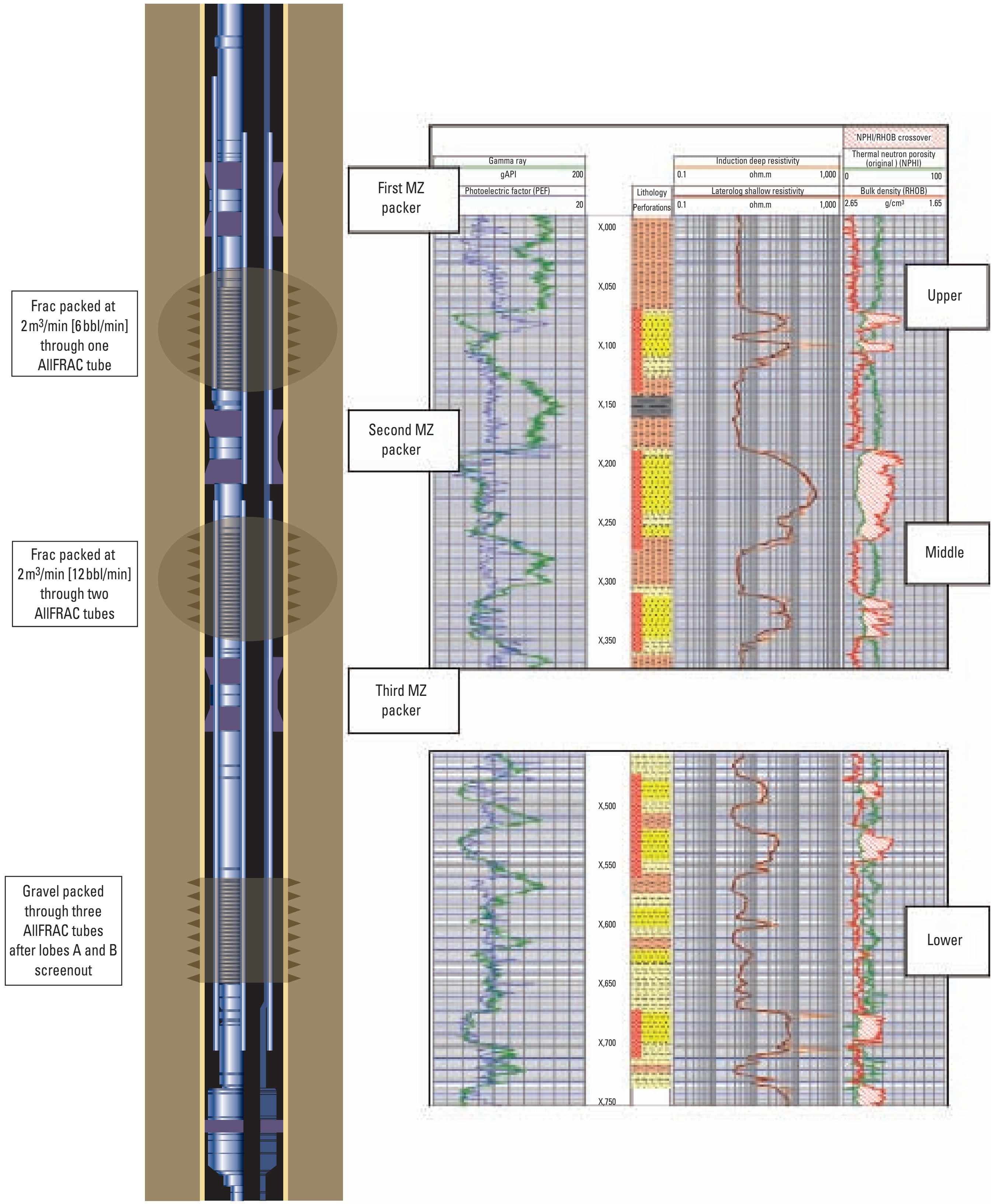


Figure 11: The completion accomplished in Well A-01, Hiu field, is shown alongside an LWD log and perforated intervals.

The highly deviated Well A-01 is in the Hiu field block B, West Natuna Sea, and is one of three subsea development wells that ConocoPhillips Indonesia (COPI) has drilled to bring the Hiu field on-stream and extend its world-class subsea complex.

The principal aims for this development project were to maximize the deliverability and the longevity of Hiu field while capping its development costs. The engineering team responsible for the field devised some extremely challenging wells. In order to intersect its reservoir targets, Well A-01 was drilled at an angle greater than 60°. The angle and the length of the gross pay interval presented significant completion challenges. Specific concerns included sand control and fluid losses during completion.

The engineering team simulated several possible scenarios for the lower Gabus reservoir, including one single frac pack for the entire interval, a multistage frac pack, and a conventional stacked frac pack. However, none of these delivered the production or cost results desired.

After careful consideration, the operators selected a single-trip completion method for the well. When the lower Gabus completion design was selected for Well A-01, the longest single-trip frac pack completed was 123 m. Everyone involved was aware that Well A-01 would stretch the technical limits of several technologies, including an integrated fracturing and gravel-packing (frac-pack) system, state-of-the-art polymer-free fracturing and loss circulation fluids, and alternate path shunts and packers.

Careful planning

The completion design for the lower Gabus reservoir involved installing a single gravel pack across the deepest sand body while simultaneously applying a stacked frac-pack completion across the two shallower lobes. The engineering team planned to perform the three lower Gabus completions in a single pumping operation. A single-trip underbalanced-perforating and frac-packing system would help to minimize fluid losses into the producing zones.

In conventional operations, additional rig time is required to kill the well with a pill, pull out of hole after perforating, make up screens and gravel-pack tools, run and set the gravel-pack–frac-pack assembly in position, and remove the kill pill to return the well to flowing. A single-trip operation, in which the perforating guns, the production screens, and the frac pack components are run into the hole together, can eliminate these steps and save up to 3 days of rig time.

A further benefit of single-trip frac packs is that productive zones do not have to be killed after the perforating operation. Instead, they take in the clean completion fluid, or a nondamaging fluid loss pill, which controls the well while completion operations take place. This approach saves rig time, improves completion efficiencies, lowers skin effects, and results in higher production rates.

Meeting the challenges

Well A-01 posed a series of technical challenges. Downhole temperatures in the well were high for using nondamaging viscoelastic surfactant (VES) fracturing fluids. In addition, the high well angle, the long gross sand interval, and the size of the nonperforated shale intervals separating the three sand lobes added complexity. Schlumberger engineers customized the completion technologies to meet these challenges.

The Alternate Path shunt tubes were modified to enable surface control of the frac-pack fluid flow rate. This rate-control option would enable the engineering team to deliver uniform fracture geometry in the upper lobes while achieving a tight annular gravel pack across all three lobes. The thickness of the nonperforated shale intervals between the productive sand lobes was significant. It meant that standard shunt tubes would be so long that the excessive friction effects inside them would result in nonuniform fracture geometry. Engineers solved this problem by adjusting the tube lengths to distribute the pumping rate precisely to each perforated interval.

The well design required the shunt tube that fed the upper lobe to be extended, while the shunt tubes for the middle and lower lobes were cut off just below the second multizone packer. Seals were added to the wash pipe that would seat against polished bores in the multizone packer to ensure zonal isolation. The shunt tubes that communicated with the middle and lower lobes were connected to create an artificial pressure drop so that the middle lobe received enough pressure for frac packing like the upper lobe, while the lower lobe would receive little fluid. This extra pressure drop would cause the shunt tubes that fed the lower lobe to activate only after the upper and middle lobes had screened out.

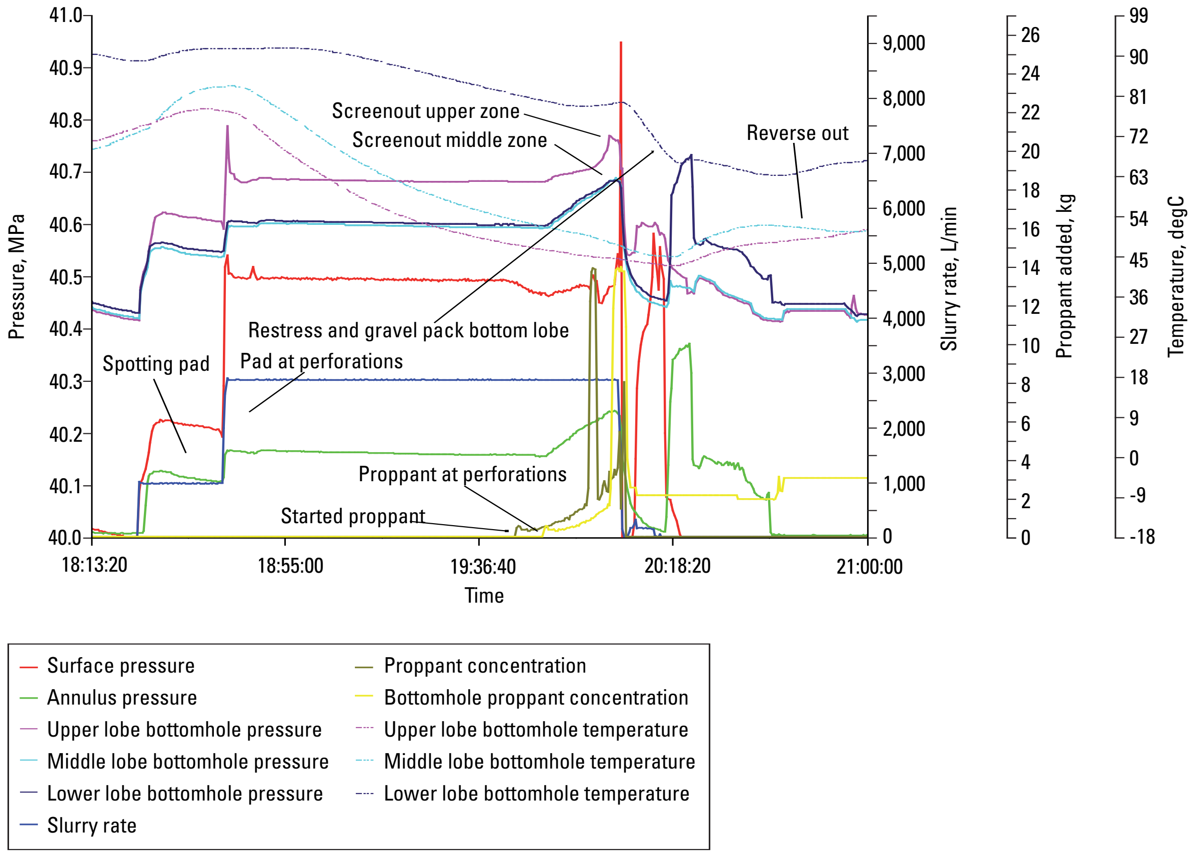


Figure 12: Bottomhole pressures and temperatures were used to monitor the effectiveness of the three-stage frac-pack operation applied in the lower Gabus reservoir.

The pumping methodology had to be adapted to match the chosen shunt-tube configuration. A system was designed to model the surface pressure for each screenout scenario. As the completion proceeded, this data would be compared with real-time surface pressure data to determine which lobe was screening out and at what rate the pumping should proceed to preserve shunt-tube integrity and optimize fracture geometry in the remaining lobes.

Optimizing the VES fracturing fluid to improve clean-up performance was also critical to the selected completion design. A high-temperature VES formulation was created for Well A-01 that included an environmentally sound zwitterionic surfactant and a specialized encapsulated breaker. This formulation could be used in temperatures up to 135 degC, reduced friction pressures in the shunt tubes more than other fluids, and had excellent proppant transport capabilities, even in highly deviated wells.

The completion was a technical success and set a new single-trip completions record. This project, which came in under budget, added USD 20 million in projected revenue and savings.

Job execution and results

The frac-pack operations were conducted in three stages: pad, proppant (slurry to first screenout), and after screenout (Fig. 12). The technology combination used was PERFPAC* single-trip perforating and gravel packing, ClearFRAC* polymer-free fracturing fluid, ClearPILL filtercake-free fluid loss pill, and multizone frac packing in one pumping operation using AllFRAC tubes. The completion was a technical success and set a new single-trip completions record. This project, which came in under budget, added USD 20 million in projected revenue and savings.

Postjob gauge pressure data indicated an effective stimulation and annular pack in all three targeted sand lobes. The well tested 42 to 50 MMscf/d of gas without condensate or sand production and initially flowed 55 MMscf/d under 2.8-MPa pipeline pressure: a figure in excess of the predrill estimates of 47 MMscf/d.

Stacking three lower Gabus sand lobes and two shallower zone 3 reservoirs into one wellbore resulted in an additional 6 to 10 Bcf in recoverable gas reserves and 10 MMscf/d in production.

To date, COPI has completed four more wells using a completions design similar to the one described here and the same technology combination. The results matched or exceeded expectations in all cases. COPI plans to apply this design in future wells, where appropriate.

The future

In the Middle East and Asia, the limited availability of stimulation vessels is one of the biggest obstacles to the wider uptake of the frac-pack method. Without a well-developed network of equipment and specialized vessels, frac packing will often only be considered for high-value operations. In other parts of the world, such as the Gulf of Mexico and offshore West Africa, the method has become a standard approach to sand control in high-permeability wells. In these areas, logistical support includes local stimulation boats that can be mobilized for small field campaigns or even individual wells.

As part of a continual process of development and optimization, engineers are looking at high-efficiency fluid systems that will help them to reduce the amount of fluid required to create a fracture in these high-permeability formations. This will save time and reduce materials costs. The ClearFRAC high-permeability system has recently been introduced and successfully utilized in Indonesia.