First UBO in Norway incorporates innovative cement design, detailed operational planning

Gullfaks field project manages bottomhole pressures by choking the return flow

IN JULY 2004 Statoil introduced underbalanced drilling technology to the Gullfaks field offshore Norway. This application – the first underbalanced drilling operation in Norway – was undertaken to overcome existing pressure control problems experienced while drilling conventionally through the cap rock in order to reach the reservoir.

This was a green project with a "zero" philosophy, meaning everyone strived for no damages to people or equipment and no release of hydrocarbons to the atmosphere or flared during the operation.

Most existing Norwegian requirements and guidelines were developed for conventional drilling. In order to meet internal Statoil standards and external Norwegian demands, the UBO surface equipment used in the project had to undergo a detailed review and extensive modifications. Additionally, because the teams consisted of personnel with very different backgrounds, high focus was kept on open communication throughout the project in order to achieve the members' common goal.

BACKGROUND

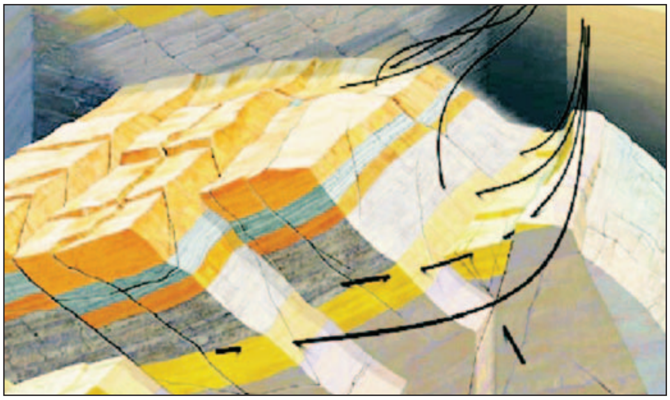
The Gullfaks field, located in the northern part of the North Sea, consists of 3 concrete gravity-based platforms and is in its tail production phase. The combination of geology and focus on maximum production had created increasing drilling problems in the Shetland formation, which is the cap rock of the Gullfaks reservoir. Excessive water injection over a limited time period caused pressure increase in certain parts of the reservoir and related fracturing of the cap rock. In certain areas, the injected water increased the pressure so much that there was no longer a window between fracturing pressure and pore pressure. Therefore, some areas of the Gullfaks field were no longer drillable with conventional drilling technology.

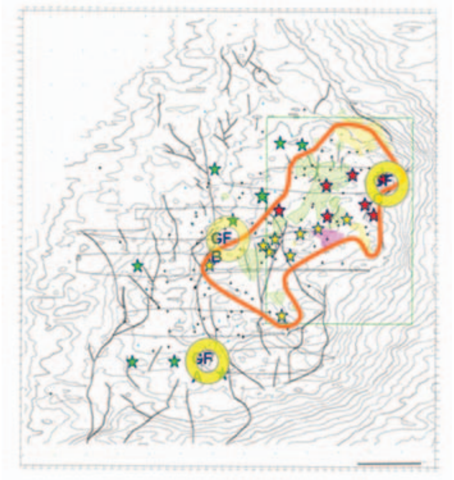
"Statoil is the biggest gas producer in the world and the second-largest oil producer, and Gullfaks was one of our most important reservoirs, with substantial reserves left in the affected areas. This was a big problem," said **Johan Eck-Olsen**, Statoil UBO Project Manager.

Mr Eck-Olsen had introduced underbalanced drilling to Venezuela in 1995. Armed with that experience, in 2001 he suggested that the company transfer the technology to Norway to resolve the Gullfaks problem.

However, since there were no existing rules and regulations made specifically for underbalanced drilling in Norway at the time, the Statoil team began by approaching the authorities to verify that the UB concept was feasible.

"From Day One, I made the Norwegian authorities a part of the team," Mr Eck-Olsen said. "They were eager and embraced the project from the beginning because they realized the importance of getting UBO technology implemented in Norway," a





Part of the complex Gullfaks field (shown above) became undrillable with conventional technology. Excessive water injection in the problem area, indicated by the red border at left, caused pressure increases and related fracturing of the reservoir's cap rock.

country where the focus is high on tail-end production optimization. A detailed study then proved the economy of the project and its need; thus Statoil's partners in the Gullfaks license came onboard.

PROJECT PHASES

The project was built over 4 phases and took place over 3 years. In the first phase, Mr Eck-Olsen built a core team, which he said focused only on positive solutions. Training on the technology took a year. They then used another year for detailed planning, and the last year was spent building the final team and executing the operation.

Underbalanced drilling isn't new – "the technology and equipment are known," Mr Eck-Olsen said, "so I put only 20% of my focus on technology and 80% on the training of personnel and team-building."

The first phase of the project began with research and learning of UBO technology. This included contacting IADC to gain access to the most updated UBO information. "In the first year when I was doing my initial training, I realized the best way was to join an international team so I could pick up knowledge that other people have already learned before me," Mr Eck-Olsen said.

This phase also incorporated the commissioning of studies on transient flow modeling and quantitative risk assessment. Feasibility studies focused on these aspects:

• Review of pressure-charged cap rock drilling experience in the Gullfaks field;

• Enabling of drilling cap rock using UBO, including a 12¼-in. new well and an 8½-in. re-entry well;

• Geology and rock mechanics aspects;

• Deck space and system layout on Gullfaks C platform (GFC);

• Tie-in of UBO separation system (SSP) to the existing platform process system;

• Compliance of UBO with Statoil internal and Norwegian rules, regulations and safety philosophy.

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The second phase – initial planning, process design, contracting and purchasing – kicked off with a team-building session that included personnel from drilling, reservoir and production departments, as well as safety delegates and Norwegian authorities.

In this phase, project teams and offices were established, and a project manual was prepared with design procedures. A preliminary HAZID (hazard identification) was conducted for Gullfaks C wells for Statoil, service contractors and potential service providers.

The team also identified UBO wells to be drilled from GFC, as well as re-entry in well 34/10 C-5A with sidetrack drilling of the 8½-in. section through the Shetland cap rock as the first candidate for UBO.

A cost, time and resources catalogue for project activities was prepared, as were Norwegian authorities consent applications, IADC accreditation for the interactive training program and a drilling permit from Norway's Petroleum Safety Authority (PSA).

Also in this phase, the team conducted HAZOP on well control procedure, 7-in. liner running procedure and 7-in. cementing procedure, and reviewed designs for the liner, the BOP stack, surface equipment, the interface between the emergency shutdown system (ESD) on the GFC platform and the process shutdown system (PSD) of the surface separation package (SSP).

In the third phase, a 4-level personnel training program – which was "built from scratch," Mr Eck-Olsen said – was implemented. This included watching a presentation of the project, 4 hours of interactive computer-based training, a 4-day well-specific UBO course for all drilling personnel, and hands-on training on the rig site. The training is certified under IADC's RigPass accreditation program.

On the field, piping for tie-ins and electrical installations were prepared. Land-based testing of the rig assist snubbing (RAS)

The mobile surface separation system consisted of 2 vessels. In the first stage, the main part of the gas was extracted and routed to the platform high-pressure flare system. Solids were removed, and liquids were routed to the second stage separator. In the second stage separator, any remaining gas was taken out and routed to the platform low-pressure flare system.

unit, SSP, cuttings transfer pump and solids removal hydrocyclone were conducted.

The drilling program was prepared for these main stages:

• Re-enter the well and drill out the cement plug in overbalanced mode;

• Drill the bottom portion of the cement plug in an underbalanced mode;

• Perform a flow test of the pressure-charged cap rock;

• Drill the remaining 8½-in. interval underbalanced;

• Run 7-in. liner and cement same underbalanced;

• Commence drilling to the pay zone target in overbalanced mode.

CEMENTING

The underbalanced operation was performed in July 2004 on Gullfaks C without operational problems or injuries to personnel, environment or equipment.

On the first well, C-05A, the cementing of the 7-in. liner was performed with a wellhead pressure of approximately 40 to 60 bars to maintain the ECD in the open hole section above the pore pressure. It was mandatory to carefully control the pressures dynamically with a surface choke to remain within the narrow pore-fracture margin during the cementing operation.

A new transient computer model for cement displacement with dynamic choke regulation was developed to make it possible to design choke operations accurately.

The model transports a sequence of fluids down through the inside of a pipe and up through an annulus outside the pipe. The fluids may have different density, rheology and volume, and may be pumped at different pump rates.

The model allows input of different boundary conditions: Either bottomhole pressure, casing shoe pressure or choke pressure can be maintained constant at a specified value.

The model has been tested and verified by comparing it with a commercial advanced ECD model and a cement design model. It was used for displacing sea water with kill mud, and the simulation results compared well with measured/observed data.

For this cementing operation, several pieces of equipment were essential:

- Rig mud pump system and cement pump;
- Rig choke;
- UBO choke;
- 4-phase separation package;
- Rotating control device;
- Mud logging system;
- UBO data acquisition system.

In the moment of bumping the plug, the well would be in "underbalance" mode, which would rapidly damage a good cement job. A dedicated mud pump was used for pumping the spacer ahead of cement and displacing cement. To be able to stop pump, close choke and pressure up annulus in the same moment, communication was crucial.

The cement slurry was batch-mixed just before starting the operation to achieve a steady choke operation so pump rate would be constant.

A 10 cu m 1.57 SG spacer was pumped at 800 l/min. The well was opened at the choke, and a steady wellhead pressure of 47.5 bar was maintained. The well was closed in with about 60 bar after having pumped the spacer.

A 7.5 cu m 1.9 SG cement slurry, including 2.2 cu m excess, was then pumped using the cement unit. The pump rate was 800 l/min, and the choke was regulated to hold 47.5 bar wellhead pressure. After pumping 1,150 liters cement slurry, the first drill pipe dart was dropped on the fly. The cement was displaced to the rig floor with the cement unit with 1,100 liters of sea water at 800 l/min. The second drill pipe dart was dropped on the fly after displacing 700 liters of sea water, leaving 400 liters of cement behind the dart. The well was again closed in with about 55 bar after displacing cement to rig floor.

Then the rig pump was used to displace the cement with 1.57 SG spacer at 800 l/min, and the choke was regulated to obtain a constant wellhead pressure of 47.5 bar.

When cement with 21.9 cu m spacer was displaced, cement entered the annulus, and the choke was regulated to obtain a pre-simulated wellhead pressure and was kept regulated based on the simulations and what was actually observed on the standpipe pressure. A high standpipe pressure peak when cement entered the liner hanger was simulated but not observed; therefore the choke was not regulated accordingly.

When the top plug bumped, the mud pump was shut off and the well was closed in with 38 bar wellhead pressure. The annulus pressure was immediately pressured up to about 60 bar using the rig pump-down kill line to achieve balanced conditions again.

During the whole operation, the liner was rotated with 20 rpm.

There was full return (no losses) during the cement operation.

After having bumped the plug, the integrity of the 7-in. liner was tested to 180 bar for 2 minutes with the cement pump.

The pressure inside the 7-in. liner was bled off, and the integrated liner top packer was weight-set by 15 tons. The packer was tested in steps of 50 bar, up to 180 bar and held for 2 minutes using the rig pump.

The wellhead pressure was bled down to 51 bar, and 60 bar pressure was applied to the string when pulling the running tool out of PBR. Excess cement was circulated out the long way, keeping back pressure on the well. There were only traces of cement observed at bottoms up.

The process was then bled off, and the well was inflow-tested for 30 minutes before pulling out of the hole with liner running tool.

Later, an additional tie-back packer was set, and the 7-in. liner was tested to 254 bar.

POST-ANALYSIS

In measured time series made after the UBO operation, the measured standpipe pressure drops far below calculated pressure after stopping pumps. The team concluded this was likely a dynamic effect: Due to inertia, fluid is flowing through the 7-in. liner shoe for a short time after stopping pumps and is prohibited to flow back into the drill string. Accordingly the pressure at the choke side will not pass through to the standpipe side. This effect was not considered important, and the model therefore assumed that fluids were allowed to flow back into the drill string.

A more important effect is the over-prediction of standpipe pressure in some periods, most importantly near the end of the job, while the cement is filling the lower part of the annulus.

The predicted increasing trend while pumping the spacer is due to the higher viscosity of the spacer compared with the drilling fluid that filled the system initially. The decreasing trend in measured standpipe pressure can be explained by one or more of the following effects:

• Spacer density is slightly higher than planned;

• Drilling fluid density is slightly lower than planned;

• Drag reduction and reduced turbulence in the spacer due to polymeric additives.

The decrease in standpipe pressure when pumping cement is accurately reproduced, except near the end where predicted pressure flattens out due to the increase in choke pressure.

When spacer is pumped after the cement, the predicted standpipe pressure is increasing slightly faster and more than the measured pressure.

• Calculation of frictional pressure loss over liner lap is incorrect. Actual shear rate inside the liner lap is far outside the range of standard Fann readings, and standard state-of-the-art frictional pressure loss models may not be accurate at such extreme shear rates.

• There was a loss of cement to the formation.

• The average open hole diameter was larger than indicated by sonic data.

Deck space was an important issue in this Norwegian underbalanced operation, as the surface separation package with the choke manifold and the pumps occupied almost all available deck space in the BOP areas.

CONCLUSIONS AND RECOMMENDATIONS

Real-time modeling of a critical cement operation was successfully applied in the first underbalanced well drilled in Norway. Procedures for maintaining constant bottomhole pressure by regulating the surface choke dynamically were developed and applied successfully. It was learned that rapid calibration and update of models while doing operations are important because important parameters can be uncertain, models have limitations and things may change during operations.

Accordingly it was experienced that modeling experts on site with access to real-time information and data produce more applicable results faster compared with experts located in offices without direct data links.

Physically, the drilling operation spanned 200 meters, although the "problem zone" was only within 40 of those 200 meters, Mr Eck-Olsen said. "Forty meters – that's 4 hours of work. We planned 3 years for 4 hours of work. But it was worth it."

For a short video showing the operation's flowline, please log on to www.drilling_contractor.org.

This article was adapted from SPE/IADC 91239, by Johan Eck-Olsen and Elin Vollen of Statoil ASA and Tim Tønnessen of Halliburton, presented at the 2004 SPE/IADC Underbalanced Technology Conference and Exhibition, held in Houston on 11-12 Oct 2004; and from SPE/IADC 92568, by Johan Eck-Olsen, Per-Johan Pettersen, Arnfinn Rønneberg, all of Statoil ASA, and Knut S. Bjorkevoll and Rolv Rommetveit, both of SINTEF Petroleum Research, presented at the 2005 SPE/IADC Drilling Conference, held in Amsterdam, The Netherlands, 23-25 Feb 2005.