Automation of Drawworks and Topdrive Management To Minimize Swab/Surge and Poor-Downhole-Condition Effects

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Summary

Careless axial and rotational movement of the drillstring can cause formation fracturing or fluid influx, resulting in costly remedial actions. With increasingly complex wellbore geometries and narrow geopressure windows, it is not always obvious for the driller how to estimate accurately the real maneuvering limits of the drawworks and the topdrive, especially under poor downhole conditions. The solution presented in this paper uses continuously updated safeguards applied to the drilling-control system to maintain a downhole pressure within the acceptable limits of the openhole formations. It automatically stops the movement of the drillstring in the case of abnormal hookloads or surface torques. Because automatic actions can be triggered in the case of an unexpected situation, some standard procedures have been fully automated, including friction tests and back reaming.

Numerical models are used to constantly calculate the maximum accelerations and velocities, which can be applied to the drillstring in the current drilling conditions. The resulting envelope of protection is dependent on many factors. Therefore, a proper evaluation of the downhole conditions is of paramount importance for the quality of the calculated safeguards. An automatic calibration of the physical models, on the basis of surface measurements, is at the heart of the system. The calibrated mechanical models are used to determine the limits for abnormal surface torques or hookloads. It is, therefore, possible to take actions automatically in the case of overpull, set-down weight, or high torque.

In 2008, a preliminary version of the system was tested during the drilling of a well in the North Sea. Even though the control algorithms did work well at that time, it was noticed that, in some circumstances, the drilling-control system would not be ready in time for fast-changing drilling conditions. An improved version of the drawworks and topdrive automation system has been tested during the drilling of three North Sea wells in the spring of 2009. In this last version, the response time of the system has been optimal at all times. The drillers involved in the testing of the system have found the system useful and user friendly.

Introduction

Lost circulation, formation influx, packoffs, and other stuck-pipe events contribute to much nonproductive time during drilling operations. In some cases, these situations can escalate into serious problems that may necessitate costly technical sidetracks. On one hand, with more and more complex wells (e.g., long horizontal sections and multilaterals) drilled in difficult reservoirs (e.g., depleted, high pressure, and high temperature), it is increasingly difficult for the driller to grasp the real limits for maneuvering the drawworks, topdrive, and mud pumps. On the other hand, the availability of high-quality surface sensors with a high sampling rate combined with downhole pressure measurements makes it possible to develop a new type of drilling-control system that is capable of continuously updating operational safeguards to respect the limitations of the openhole formations. Using such high-quality data with a model-based drilling-control system, automatic actions can be triggered much faster than if they were triggered by a person and, therefore, can minimize the effect of unexpected events on the wellbore.

The system presented in this paper focuses on the drawworks and topdrive management. After explaining the different implemented functions, a brief overview of the underlying methodology is given. The system has been developed over several years and was finally tested in real drilling operations over a period of 4 months (Larsen et al. 2010). Practical considerations needed to be addressed for implementing the new drilling-control system on a fixed platform offshore Norway. At the end of the paper, the results from the 4 months of testing are reported.

Functions

In the following, the functionalities of the system are presented. They are all directly accessible from the drilling-control system. The aim of the first one (axial-velocity control) is to prevent exceeding some continuously updated operational safeguards. The second and third ones (maximum overpull/minimum set-down weight and maximum torque) are automatic actions triggered when unexpected events are detected. Finally, taking advantage of the first functionalities, automatic sequences have been implemented (friction tests and autoreciprocation). The two automatic sequences, thus, constitute the last of the five presented functionalities.

Axial-Velocity Control. When turned on, this first functionality limits the axial velocity and acceleration that the driller can apply to the drillstring. Many parameters are involved in the estimation of those limits. The different types of limitations used by the system are listed later.

The axial movement of pipes in a hole generates an additional downhole pressure in the annulus, which can be positive (surge) for a downward movement or negative (swabbing) when the pipes are moved upward. This variation of pressure is transient and depends on the acceleration and velocity of the pipes in the borehole (Mitchell 1988, 2004). If the downhole pressure decreases below the pore pressure of some region of the openhole section, formation fluids will flow into the annulus at a rate that depends on the pressure differential, the porosity and permeability of the formation, and the properties of the formation fluids (Vefring et al. 2006). If the downhole pressure is lower than the collapse pressure of some geological sections, blocks of formation rocks will fall down into the wellbore. On the other hand, if the downhole pressure goes beyond the fracturing pressure of the openhole formation, fractures will be generated and drilling fluids will flow into the rock. The maximum of the pore pressure and the collapse pressure of the openhole formation defines the lower bound of a geopressure window, whose higher bound is limited by the minimum fracturing pressure of the exposed formation rock. While moving the pipes axially, therefore, it is important to maintain the string acceleration and velocity in such conditions that the downhole pressure remains within the geopressure window of the openhole section. The distance by which the pipes are moved will influence the generated swab and surge pressures. Usually, the pipes are preassembled in stands of three or possibly four single pipes, and, therefore, the maximum displacement of the string is limited by the length of a stand. At any time, on the basis of the

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maximum displacement and the current downhole conditions, it is possible to calculate the absolute maximum acceleration, velocity, and deceleration that ensure that the downhole pressure remains within the geopressure window.

On a floating platform, the string movement is influenced by heave. Without heave compensation, the string is constantly subjected to accelerations because of the vertical motion of the rig induced by waves. Therefore, any velocity control of the string to manage swab and surge pressure must account for the maximum acceleration and velocity that are superimposed on the relative movement of the string with respect to the drillfloor. Even when heave compensation is used, small heave-related movements are added to the string motion, resulting in additional accelerations and velocities. To maintain a downhole pressure within the geopressure window, the system adjusts the safeguards applied to the drawworks maximum acceleration, velocity, and deceleration with the worst possible effect of heave either with or without heave compensation.

The actual drawworks capabilities can limit the achievable accelerations, velocities, and decelerations of the pipe axial movement. On the basis of parameters such as the drawworks motor characteristics, the available energy from the power generators, the gear and clutch reduction ratio, the number of wires in the hoisting system, and the current hookload, the drilling-control system can estimate the safe operating range of the drawworks rotational velocity at a given moment.

When approaching places with changes in hole diameter (e.g., casing shoe, liner hanger, and milled window), it is recommended that a reduced axial velocity be used when passing through those areas with the largest elements of the string [e.g., the bottomhole assembly (BHA)]. Such speed reduction is also applicable for tight spots in the wellbore. The system takes into account those specific speed reductions. In addition, whenever key seats, ledges, or high-dogleg zones are observed during a drilling operation, the trouble zones are recorded and reduced tripping velocities are applied to pass through those regions with the largest elements of the string.

At the planning stage, the maximum axial velocities for standard drilling or tripping conditions are often calculated. Those velocity limits may apply for various depth ranges. Those depth ranges are often related to the openhole section but can also be associated with situations where large elements of the string are moved inside a narrow casing or liner. Such velocity constraints are gathered into a detailed operation plan and are used by the system.

Finally, the driller may want to use a reduced speed when there is a risk of taking weight. The higher the string velocity is, the faster the reaction time for stopping the movement should be when abnormal hookloads are observed, to avoid serious damage to the well or the string. A substantial comfort can be provided to the driller by having an easy way to set the maximum drawworks speed in areas where abnormal hookloads can occur. This last type of speed limitation is managed by the system.

During previous tests of the system, only the downhole transient pressure and the geopressure window combined with the power-based limitation of the drawworks were used to calculate the dynamic axial-velocity limits (Iversen et al. 2006, 2009). However, the actual full-fledged version of the axial-velocity control that accounts, at any time, for the minimum of the following conditions has:

- Safeguards based on the predicted downhole pressure with regard to the geopressure window
- Adjustments on these safeguards to account for heave effects and whether the heave compensator is in use
- Power-based maximum drawworks capabilities
- Velocity reduction when approaching change of hole diameter and trouble zones
- Maximum speed limits imposed in the detailed operation procedure
- Maximum speed chosen by the driller

For emergency situations, it is easy to bypass those limits and apply the maximum available drawworks effect; however, the powered-based maximum drawworks capabilities should never be bypassed.

Maximum Overpull and Minimum Set-Down Weight. During axial pipe movement, the risk of taking weight always exists. When the pipes are moving upward, the risk is to take an overpull; while, for downward movement, the risk is to get a set-down weight. In both cases, an obstacle of some sort is slowing down or prohibiting the string movement, resulting in a sudden variation of the hookload. Such obstacles can be an accumulation of cuttings, a formation collapse, a ledge, a key seat, or some kind of junk. When a too-high overpull or set-down weight is detected, the system automatically stops the string movement to avoid making the situation worse.

A different approach is applied when the mechanical friction is increasing abnormally. The causes for a deterioration of the friction condition can be, for example, poor hole cleaning, hole collapsing, or microtortuousity. The consequence of the friction increase is an abnormal evolution of the hookload as a function of depth (Vos and Reiber 2000). When the increase in friction goes beyond a certain threshold, the system displays warnings in the drilling workstation and the string movement is stopped until corrective actions have been taken (Cayeux and Daireaux 2009). The difference compared to an instant overpull is that alarms are displayed before the string movement is automatically stopped.

In the case of a stuck-pipe situation, it is necessary to work the pipes free. In this context, it is important to apply forces that respect the maximum admissible loads of the pipes in the string. When stretching the pipes, the maximum limit is the yield strength. Conversely, when slacking off the string, the maximum limit is imposed by buckling conditions. Both circulation and rotation can be applied simultaneously to the axial forces, and the applied limits should account for the combined effect of all involved forces. The drawworks control system limits the movement of the hoisting system to maintain hookloads in the permissible range with regard to the current circulation and rotational conditions **(Fig. 1).**

After taking weight, or when excessive friction is observed, it is easy to bypass the imposed constraints in order to work the pipe free if necessary. Similarly, it is possible to turn off the maximum-hookload limits and take the risk of breaking the string if any other actions have been unsuccessful.

Maximum Torque. The deterioration of downhole conditions, for instance because of poor hole cleaning, can result in an increase of the mechanical friction, which, in turn, has a direct effect on the surface torque. When the friction overpasses a certain threshold value compared to the optimal friction situation, the topdrive torque gets limited to the maximum tolerable value under the deteriorated downhole conditions. The resulting action is a decrease of the topdrive rotational velocity, which ultimately can lead to full rotation stop.

When the hole is packing off or collapsing, the topdrive torque is usually becoming erratic. In such conditions, the topdrive should be stopped and remedial actions should be started.

While working the pipes to get free from a stuck-pipe situation, the system will apply the maximum allowed torque for the weakest element in the string as limits for the forces applied to the string. Because both axial forces and circulation may be used while torque is applied, it is important to account for the combined effect of all forces for the maximum torque limitation.

It is possible to bypass the torque limitation arising from maximum friction deviation or erratic torque response in order to work the pipe in a stuck-pipe situation. It is further possible to remove the maximum-torque limitations, if one is willing to risk twisting off the pipes to get free during a stuck-pipe event.

Friction Test. It is usual to record the free rotating weight and torque as well as the pickup and slack-off weight after drilling a stand in order to have comparison values to detect abnormal hookloads and torques. Such a procedure consists of picking up the string at a constant velocity for a short distance, starting rotation without any axial movement for a certain time, and, finally, slacking off the string at a constant speed to return to the original position. Note that, just after picking up the string, the pipes are in tension and starting the rotation in this condition generates a peak

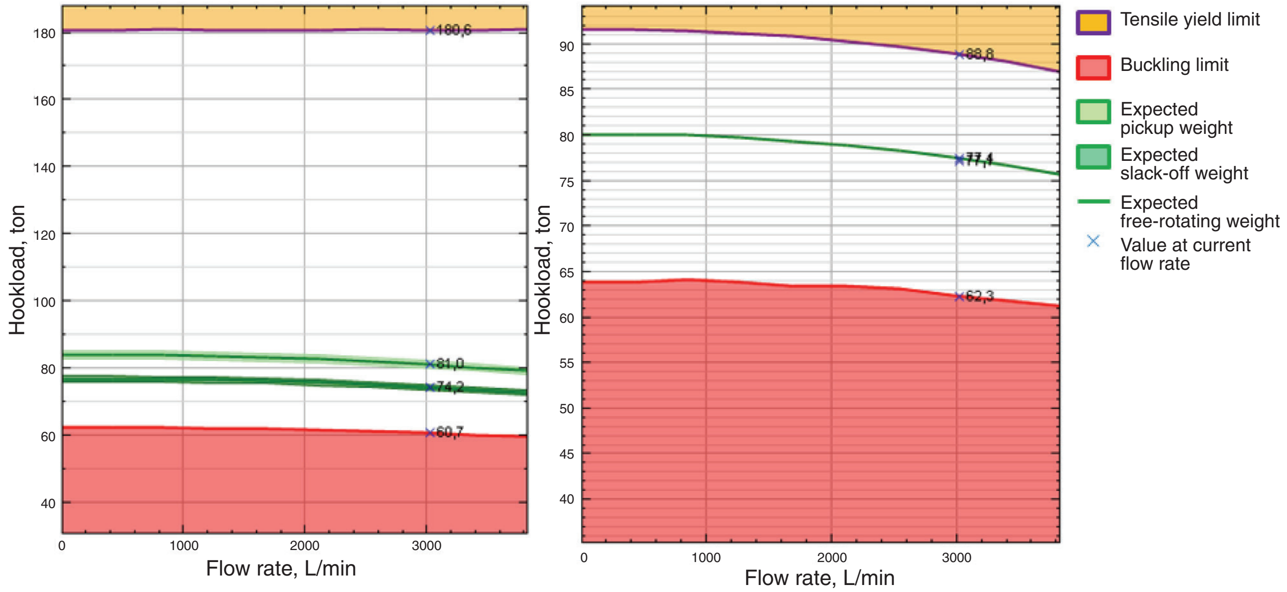


Fig. 1—The left-hand graph shows the dependency of the predicted hookloads and extreme values (tensile-yield limit and helical-buckling limit) as a function of the flow rate and the direction of movement in sliding conditions. The right-hand-side graph shows the dependency of the predicted free rotating weight and extreme values (tensile-yield limit and sinusoidal-buckling limit) on the flow rate when there is rotation. These data are based on a test of the described system during a drilling operation in the North Sea.

of torque, which, for long or tortuous wells, can be detrimental. Therefore, it is necessary to slack off the string just before starting the topdrive to release the tension in the pipes.

By automating a friction-test sequence **(Fig. 2),** it is possible to obtain hookload and torque measurements in almost perfect steady-state conditions (constant axial string velocity). Those conditions are always the same from friction test to friction test and, therefore, are ideal for comparison of the evolution of the surface parameters (Guild et al. 1995). However, there is always a risk of taking weight or having abnormal torque while running the test. The simple idea of just sequencing the pipe movements to conduct the test could reveal itself as the source of serious incidents if it is not capable of reacting to unexpected events. Therefore, a prerequisite for automating such a sequence of pipe movement is the availability of safeguard calculations of axial-velocity limits to avoid excessive downhole pressures, hookload overpull and set-down weight limits, and maximum topdrive-torque limits.

The friction-test sequence can be started only when there is sufficient height clearance for the block in the derrick.

During the execution of a friction-test procedure, the traveling equipment and the string are moving without the control of the driller; therefore, it is also crucial that the driller be able to interrupt the test in a simple and intuitive manner in case something or someone gets in the way.

Autoreciprocation. To improve the hole conditions, it is usual to perform a back reaming/reaming of a single drillpipe or a complete stand before making connection. The rotational velocity and pump rate used for reaming are normally reduced compared with the back-reaming sequence, to minimize the risk of natural sidetrack and formation fracturing associated with the downward movement of the string.

It is possible to automate such a sequence in the same way as the friction test **(Fig. 3).** Again, this sort of automation is precon-

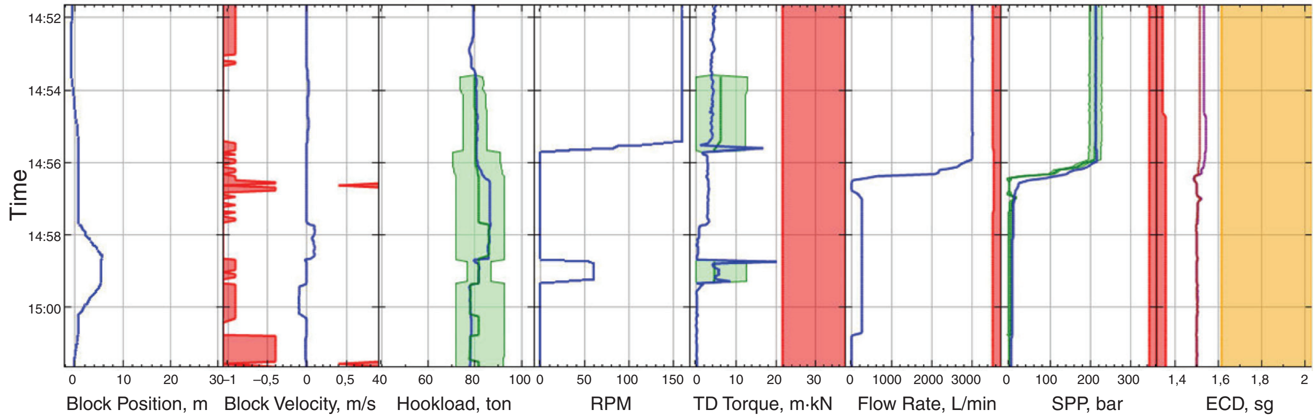


Fig. 2—Example of an automatic friction test. Note that the string is slacked off slightly before starting rotation in order to reach the free rotating weight and thereby avoid excessive torque when starting the topdrive. The blue lines are the measured values. The semitransparent red and orange regions represent the boundary limits calculated by the system. The semitransparent green areas show the predicted values (including the uncertainty in the calculation) using the calibrated physical models. The brown and purple lines in the downhole ECD tracks are the calculated downhole ECD at the closest proximity to, respectively, the pore-pressure gradient and fracturing-pressure gradient. These data were recorded during an offshore test in the North Sea. TD: top-drive.

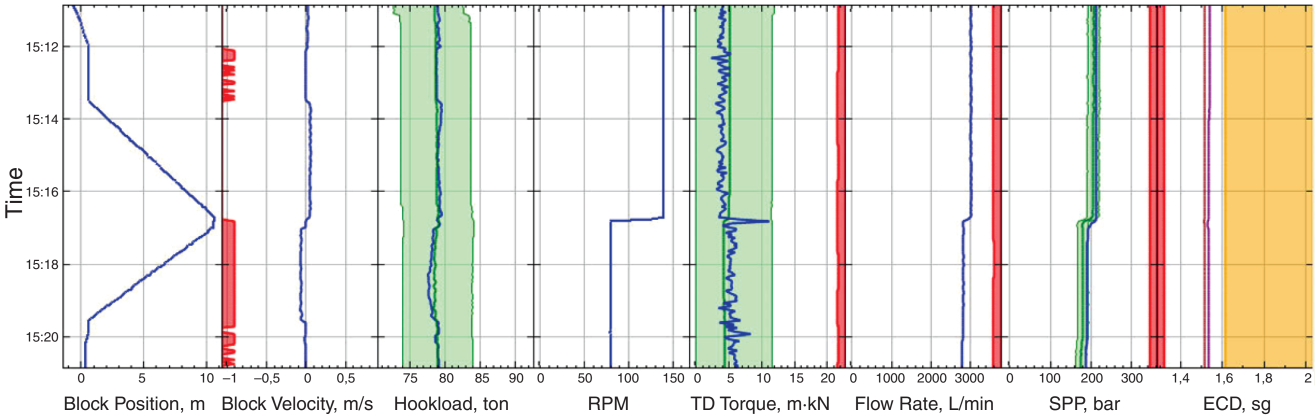


Fig. 3—Example of an automatic reciprocation sequence. Note that the flow rate is reduced between reaming up and down as well as the topdrive RPM. The blue lines are the measured values. The semitransparent red and orange regions represent the boundary limits calculated by the system. The semitransparent green areas show the predicted values (including the uncertainty in the calculation) using the calibrated physical models. The brown and purple lines in the downhole ECD tracks are the calculated downhole ECD at the closest proximity to, respectively, the pore-pressure gradient and fracturing-pressure gradient. These data were recorded during an offshore test in the North Sea.

ditioned with the availability of axial-velocity control for avoiding detrimental downhole pressures, hookload limitations in the case of overpull or set-down weights, and torque limits. Because the mud pumps are most likely running during this operation, it is also important to have an automatic pump-shutdown mechanism in case an obstruction reduces the flow path while running the autoreciprocation procedure. This type of mud-pump control is described in Cayeux et al. (2011).

As with the friction-test procedure, it is not possible to start the sequence if there is not enough space compared with the highest acceptable block position.

Easy and intuitive interruption of the procedure is available to deal with unknown dangerous situations.

Methodology

In order to implement the functions described, the system must compute various safeguards continuously: hookload margins, surface-torque margins, and axial-velocity limits with and without circulation. This is achieved by running torque-and-drag and swab-and-surge simulations. Many parameters affect those computations. Among them are

- The drilling-fluid properties
- The temperature gradient in the annulus
- The gel time if there is no circulation or, otherwise, the circulation rate
- The wellbore and string geometry
- The actual barite proportion along the hole when there is barite sag
- The proportion of cuttings in suspension in the mud but also the presence of cuttings beds or caved areas because it is influencing the clearance between the pipes and the borehole wall

Some of those parameters remain constant throughout the drilling operation; others are evolving all the time. It is possible to use physical models to evaluate the evolution of some of the varying parameters, but others need to be estimated on the basis of observations (Gravdal et al. 2005). The five next subsections describe the various aspects of the methodology used to perform the real-time estimation of the well mechanical, hydraulic, and thermal status. Following this, the last four subsections are devoted to the computation of the safeguards themselves.

Continuous Drilling-Fluid Pressure/Volume/Temperature (PVT) Estimation. The mud density plays an important role in pressure-loss and buoyancy calculations, which, in turn, are essential for calculating swab and surge pressures as well as hookload and torque limits. The downhole mud density at any depth is influenced by the local temperature and the solids content (cuttings and barite proportion).

The temperature gradient of the drilling fluid in the string and in the annulus is evolving continuously with time as a function of the different circulation periods. While circulating, pressure losses are transformed into heat; moreover, the bit is heating the mud when drilling is taking place. However, heat is transferred between the fluid in the string and the mud in the annulus through the pipes and from the drilling mud in the annulus to the formation rock either directly or through the casing strings and cement layers. When circulation is stopped, heat is transferred between the different parts of the system through natural convection. By continuously running a transient hydraulic model (Sævareid 2001) coupled with a heat-transfer calculator (Corre 1984), it is possible to follow the evolution of the temperature gradients of the drilling fluids inside the string and the annulus during the drilling process.

The transient hydraulic model is used to estimate the cuttings transport as a function of the flow rate and rotational velocity of the string (Larsen 1990; Jalukar 1993; Bassal 1995). The same hydraulic model is used further to evaluate the barite proportion at any annulus depth, using a barite-sag model (Saasen et al. 1995).

Combining the local temperature of the fluid with the solids content (high-gravity-solids proportion and cuttings proportion), a PVT model is used to estimate the current density of the drilling fluid at any depth. The estimation of the compressibility and thermal expansion of the mud can be based either on empirical models or on PVT approximations of the base components (oil and water). A PVT approximation can be described by a table of density as a function of pressure and temperature or by a six-parameter two-dimensional function (Ekwere et al. 1990; API Recommended Practice 13D 2006; Thorsrud et al. 2000). Unfortunately, these tables or six parameters describing the base oil or brine thermal expansion and compressibility are usually not easily accessible outside the drilling-fluid provider company. Alternatively, it is possible to use empirical models such as those of Glasø (Glasø 1980), Standing (Standing 1947), and Sorelle (Sorelle et al. 1982). However, experience has shown that those models are far from being accurate enough for modern drilling fluids. The current fluid temperature, density, cuttings, and barite gradients then are made available for all other calculations.

Downhole-Drilling-Conditions Evaluation. The mechanical friction between the string and the borehole is used to estimate hookloads and topdrive torques. However, this friction may change during the drilling process because of the amount of cuttings in the annulus. Furthermore, the rotational friction may be slightly different from the sliding friction. Therefore, it is important to distinguish conditions of pure sliding from situations where rotation is used. When the bit is off-bottom, it can be assumed that the bit torque and the weight on bit are zero. Because the hookload

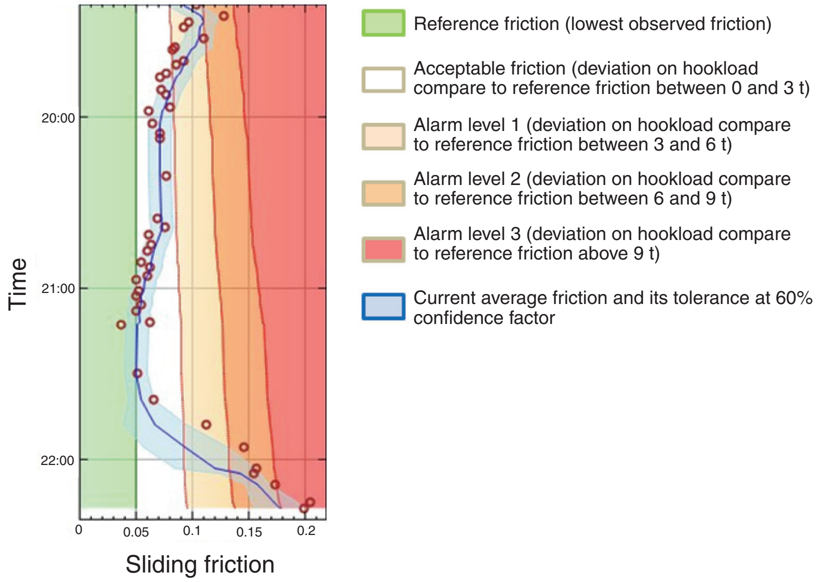


Fig. 4—This graph shows the sliding friction evolution with time during a pull out of hole. The lowest ever observed friction is the reference friction (in green in the plot). The current friction (in blue in this chart) may vary because of downhole-condition variations (such as in this example when the BHA is dragged into a bed of cuttings from 21:30). These data were recorded from a drilling operation in the North Sea.

and the surface torque are measured, it is possible to use those measurements to estimate the mechanical friction. The observed friction not only reflects the friction coefficient of the Coulomb friction law between the drillstring and the borehole but also the current downhole conditions. For instance, cuttings beds have an influence on drag forces when the BHA is picked up or slacked off. These additional drag forces are interpreted as an increase of the global coefficient of friction for the wellbore. Thus, it is valuable to determine the lowest friction ever observed in order to estimate the best possible downhole conditions. This friction is called the reference friction. The discrepancy between the current friction and the reference friction provides a way to quantify the deterioration of the downhole conditions **(Fig. 4)**.

Pressure drops inside the drillstring and in the annulus contribute to the set of forces applied to an element of drillpipe (Douglas et al. 1986); therefore, the hookload and surface torque are influenced by the effect of circulation. Consequently, it is important to use a mechanical model that accounts for hydraulic effects. If the circulation effects were not considered, the calculated frictions would be significantly biased as soon as there is a substantial flow rate. This bias would be attributed to a deterioration of the downhole conditions, while, in fact, it is physically explained by the effect of the fluid movement inside the pipes and the annulus.

Because the calculation of the mechanical friction is dependent on correct evaluation of pressure drops along the string and in the annulus when circulation is established, it is important to have a correct estimation of pressure losses. As for the mechanical friction, the annulus hydraulic friction is not constant because it is largely influenced by the downhole conditions. When bottomhole pressures are measured (using a downhole pressure sub), it is possible to calculate a correction factor to be applied on the computed pressure losses in the annulus in order to match the measured downhole equivalent circulation density (ECD). A correction factor of unity means that no correction is necessary. A correction factor smaller than unity indicates that the actual downhole pressure is lower than expected. This can be caused by hole enlargement, for instance. A correction factor larger than unity is a sign that the pressure losses are larger than the prognosis, which can be the case when there is a hole-size restriction or a high cuttings concentration **(Fig. 5)**. The current correction to the annulus hydraulic friction is made available for the rest of the calculations.

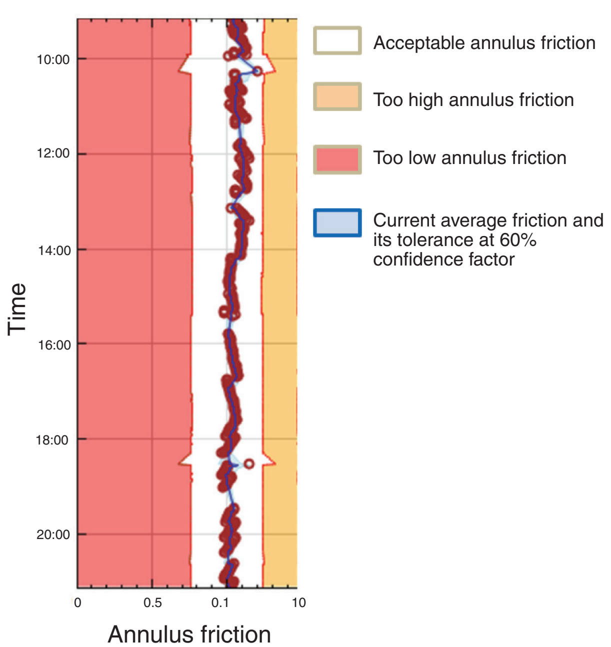


Fig. 5—This graph shows the annulus-friction evolution with time after reaching the final depth of the section (from 9:00 to 14:00) and during pure circulation (from 14:00 to 21:00). An annulus friction of unity means no correction to the pressure calculations in the annulus. An annulus friction greater than unity means that the downhole conditions are generating more pressure losses than expected. These data were recorded from a drilling operation in the North Sea.

Global Model Calibration. Conversely, the hydraulic friction in the string is not dependent on external varying conditions, though the model-based calculation may need to be adjusted to match the measured pump pressure to account for small discrepancies in the pipe roughness and geometry as well as some uncertainty in the fluid properties. A "fudge" factor is estimated to correct the hydraulic friction in the string. A fudge factor of unity will correspond to no correction. A fudge factor larger than unity corresponds to increasing the model output, while a fudge factor below unity corresponds to decreasing the model output. This corrective factor may be dependent on the flow rate; but, for a given pump rate, it should be constant for any bit depth, as long as the

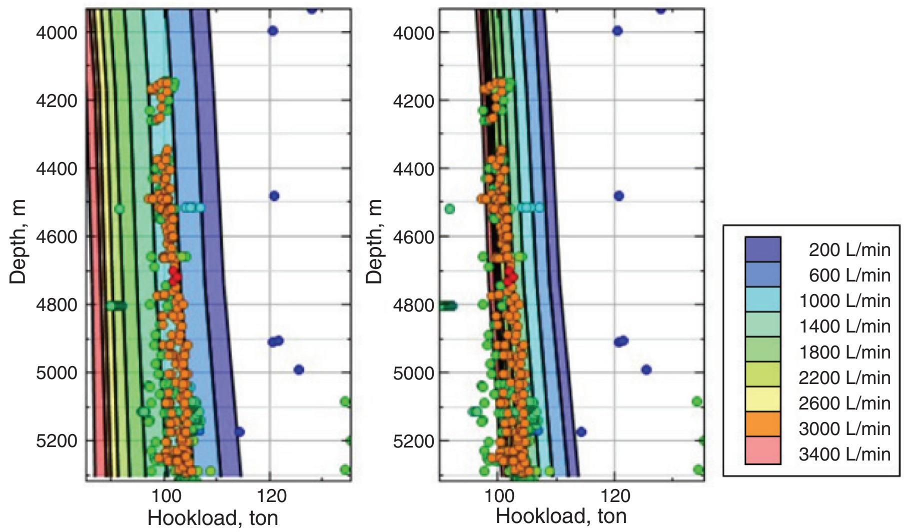


Fig. 6—These two graphs show the free rotating weight at different flow rates (color coded as follows: low flow rates are in red, high flow rates are in blue) as a function of the bit depth. The continuous curves are calculated by a torque-and-drag model coupled with a hydraulic model. The markers are real observations. Both curves and markers use the color code as displayed in the legend: A dark blue marker corresponds to a measurement made with a circulation rate in the range 0–200L/min, and the two lines delimiting the dark blue continuous area are computed with circulation rates of 0 L/min (right curve) and 200 L/min (left curve). The graph on the left-hand side is calculated using an uncalibrated model. The graph on the right-hand side is constructed using a calibrated model.

drilling-fluid properties are not changing much. In practice, a fudge function of the flow rate is calculated such that the hydraulic-model calculations are matching the measured standpipe pressure (SPP) at any depth and flow rate. In the procedure for estimating the fudge function, it is important to account for the actual temperature gradients and observed annulus hydraulic friction at the time of the SPP measurement, to remove any source of bias. The string hydraulic-friction correction function is made available for the rest of the calculations.

Similarly, the accuracy of torque-and-drag calculations is influenced by the linear weight of the pipes used in the string. Wear on tubulars may reduce the actual linear weight and, therefore, be the cause of discrepancies between calculated hookloads and measured ones. When rotating the string without axial movement, the hookload is independent of the mechanical friction. By calibrating the model during such conditions, it is possible to adjust the linear weight of the pipes in the model that contribute the most to the total weight such that the model matches the free rotating weights. Unfortunately, rotation off-bottom is often made with circulation. Therefore, it is not that simple to correct the linear weight of the pipes because pressure losses are influencing the hookload (Bhalla and Walton 1998). Using a torque-and-drag model that is coupled with the hydraulic and temperature model, it is nevertheless possible to circumvent that difficulty because the dependence of the hookload on the flow rate at a given bit depth can be estimated by the models. The next problem is to make sure that the hydraulic coupling with the mechanical model is globally calibrated **(Fig. 6).** Finally, the linear weight corrections and the correction factor for the coupling between the hydraulic model and the mechanical models (which will be called the hydraulic mechanical efficiency from here on) are made available for the rest of the calculations.

Active BHA Components. Some components of the drillstring can change the drilling conditions dramatically. For instance, a circulation sub can divert the drilling fluid flow to the annulus at a much shallower depth than when the mud is flowing through the bit. Or an underreamer may enlarge the hole size and, therefore, affect the pressure losses in the annulus. The difficulty for an automatic control system that uses physical models is to make sure that it can interpret these situations correctly and perform the calculations with the correct geometry.

One way to activate a BHA component is to drop a ball in the drillstring. When the ball lands on a seat in this particular component, it switches the tool to a different mode (for instance opening the arms of an underreamer). There are no signals informing the drilling automation system of such an event. In order to recognize the change made to the active component, the system monitors the evolution of the pump pressure after a topdrive connection is made in order to evaluate whether a pump-pressure variation can be the signature of a ball landing in the tool. If such an activation signature is recognized, the internal status of the component is modified to reflect the detected action for all other calculations.

Heave Prognosis. On a floating platform, heave movements are superposed onto the axial movement of the string with respect to the drillfloor. If the heave compensator is used, the residual movements are of small amplitude. Otherwise, the heave velocity and acceleration depend on the weather conditions. In a worst-case scenario, the heave acceleration and velocity are maximal and in the same direction exactly at the moment when the axial velocity and acceleration of the string (compared to the drillfloor) are at their apogee. In order to account for heave effects, it is necessary to have a good prognosis of the maximum acceleration and velocity that can happen within the time at which the string will be picked up or slacked off.

Statistical analysis of the distribution of the heave amplitudes, velocities, and accelerations is performed over a period (typically half an hour), and a 99% confidence factor is used to estimate the maximum velocity and acceleration that can be expected in the near future. The heave prognosis is then made available for the other calculations.

Hookload Margins. When the string is rotating, the hookload is independent of the mechanical friction, but it is influenced by the flow rate. Using the global calibration of the linear weights and the correction factor for the coupling between the hydraulic model and the mechanical model, a hookload is estimated. The standard deviations on the correction factors for the linear weight of the different pipes and the hydraulic mechanical efficiency are used to evaluate the tolerance on the calculated hookload. Those hookload bounds are sent to the drilling-control system as maximum acceptable hookloads when the string is moved upward or downward. An absolute maximum hookload is calculated to the limit of elasticity of the string. This value is used for working pipes in the case of a stuck-pipe situation where rotation is still possible. Finally, an

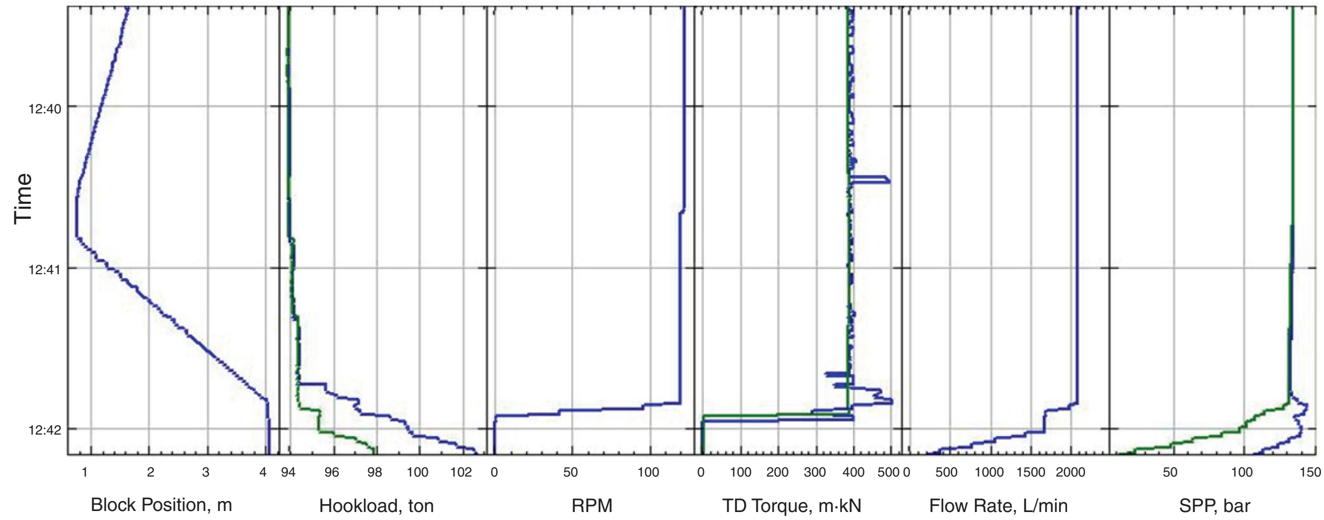


Fig. 7—Example showing how the drilling-control system reacts automatically to an overpull while tripping out of hole. The blue lines are the measured values. The green lines are the expected values calculated by the system. Note that, while taking weight, the driller still maintained maximum upward velocity so the actual stop is because of the maximum overpull limit. These data have been generated using a replica of the offshore drilling-control system in a virtual rig environment.

absolute minimum hookload is calculated to the limit of sinusoidal buckling, which is used when the driller is bypassing normal hookload limits.

If there is no rotation, the pick-up and slack-off weights depend on the friction and the circulation rate. The currently observed sliding friction and its associated standard deviation are used to estimate normal boundaries for the hookload. Those boundaries are useful for reacting to a sudden overpull or set-down weight. Similar boundaries are calculated using the reference sliding friction (i.e., the smallest friction observed so far, which correspond to the best downhole drilling conditions) and a maximum overpull (set-down weight) threshold. These boundaries are used to detect that the downhole conditions have deteriorated above acceptable criteria. The intersection of those two boundaries is sent to the drilling-control system. The drilling-control system makes sure that the hookload stays within those limits (possibly prohibiting any axial movement; see **Fig. 7**). In order to work the pipes during a stuck-pipe situation, an absolute maximum hookload is calculated to the elasticity limit of the string. An absolute minimum hookload is calculated to the limit of helical buckling, to be used when normal limits are bypassed.

Surface-Torque Margins. When the bit is off-bottom, the bit torque is negligible. The surface torque varies with the rotational friction and the flow rate. By using the globally calibrated mechanical and hydraulic models and the current friction and its standard deviation, it is possible to calculate a maximum tolerable surface torque at any time. If the torque increases abnormally or becomes erratic, the calculated torque limitation applied to the topdrive attenuates the side effects. Furthermore, it is possible to calculate a maximum surface torque on the basis of the optimum friction (the smallest rotational friction observed in the current conditions) and an acceptable threshold. The minimum of the two limits is used for the topdrive-torque limiter.

An absolute maximum torque considering the weakest elements in the string is calculated accounting for the effect of the flow rate and tension in the string. This torque, corresponding to the elasticity limit of the pipes, is used for working the pipe during a stuck-pipe situation.

Axial-Velocity Limits Without Circulation. When there is no circulation, the gel time influences the maximum axial velocities that can be used to move the string upward or downward **(Fig. 8).** The transient hydraulic model is used for evaluating the maximum accelerations, velocities, and decelerations for moving one stand either upward or downward. The first attempt is to use the maximum machine limits for the accelerations and velocities. If the generated downhole pressures cannot stay within the geopressure window for the whole of the openhole section, then the second attempt is to reduce the acceleration while attempting to achieve the maximum machine velocity. The lowest acceleration considered depends on whether the system is used on a fixed or floating platform. When heave is to be considered, the minimum acceleration corresponds to the maximum predicted heave acceleration, otherwise the length of the acceleration phase is limited to one-third of the stand length. If, while using the minimum acceleration, it is still not possible to respect the geopressure window, the maximum velocity is decreased (using the minimum acceptable acceleration) until the downhole pressure stays within the geopressure margins. Finally, the deceleration phase is studied. The maximum machine deceleration is used by default; however, if the generated downhole pressure pulse cannot be maintained within the geopressure boundaries, the deceleration is reduced. If heave has to be considered, the actual safeguards sent to the drilling-control system are reduced to account for the maximum expected heave velocity and acceleration. All those calculations are made using the globally calibrated hydraulic model and the current annulus-friction-correction factor. The estimated thermal gradients and cuttings and barite proportions are also used.

Axial-Velocity Limits With Circulation. If a drilling fluid is circulated, similar calculations are made. The noticeable difference, of course, is that the gel-time condition is replaced by the flow rate **(Fig. 9).** To make sure the calculated swab and surge values are safe, the simulations use a high rotational velocity for the downward movement because rotation of the pipes will increase the pressure losses and, therefore, the downhole pressure. On the other hand, no rotation at all is considered when moving the pipe upward because the most constraining factor is close proximity to the lower side of the geopressure window **(Fig. 10).**

User Input and Configuration

The presented system is in constant interaction with the different users, drillers, and drilling engineers. The general configuration of the system, as well as each simple functionality, has its own dedicated user interface, integrated in the drilling workstation when necessary.

General Configuration of the System. In order to run the system properly, it must be configured correctly. Independent of the operational parameters for the different functionalities, the wellbore description must be entered into the system. This can be

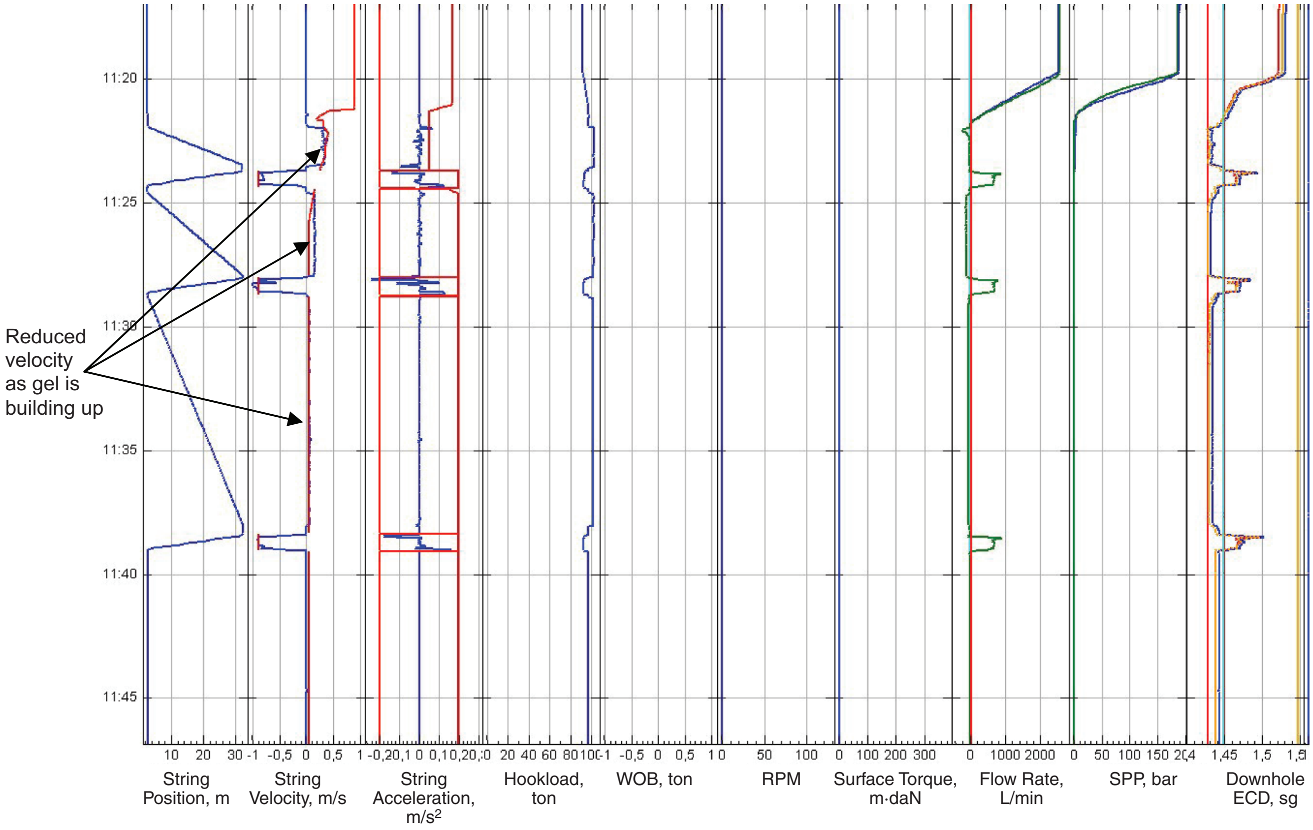


Fig. 8—Example showing the effect of gel time on tripping velocity. The blue lines represent the measured values. The red and orange lines are the maximum limits calculated by the system. The green lines are the expected values based on the calibrated physical models. The brown and purple lines in the downhole ECD tracks are the calculated downhole ECD at the closest proximity to, respectively, the pore-pressure gradient and fracturing-pressure gradient. The turquoise line in the downhole ECD track is the mud weight. The same stand is picked up and slacked off just after stopping the mud pumps. One can see that the upward velocity is reduced when gel is building up. These data have been generated using a replica of the offshore drilling-control system in a virtual rig environment.

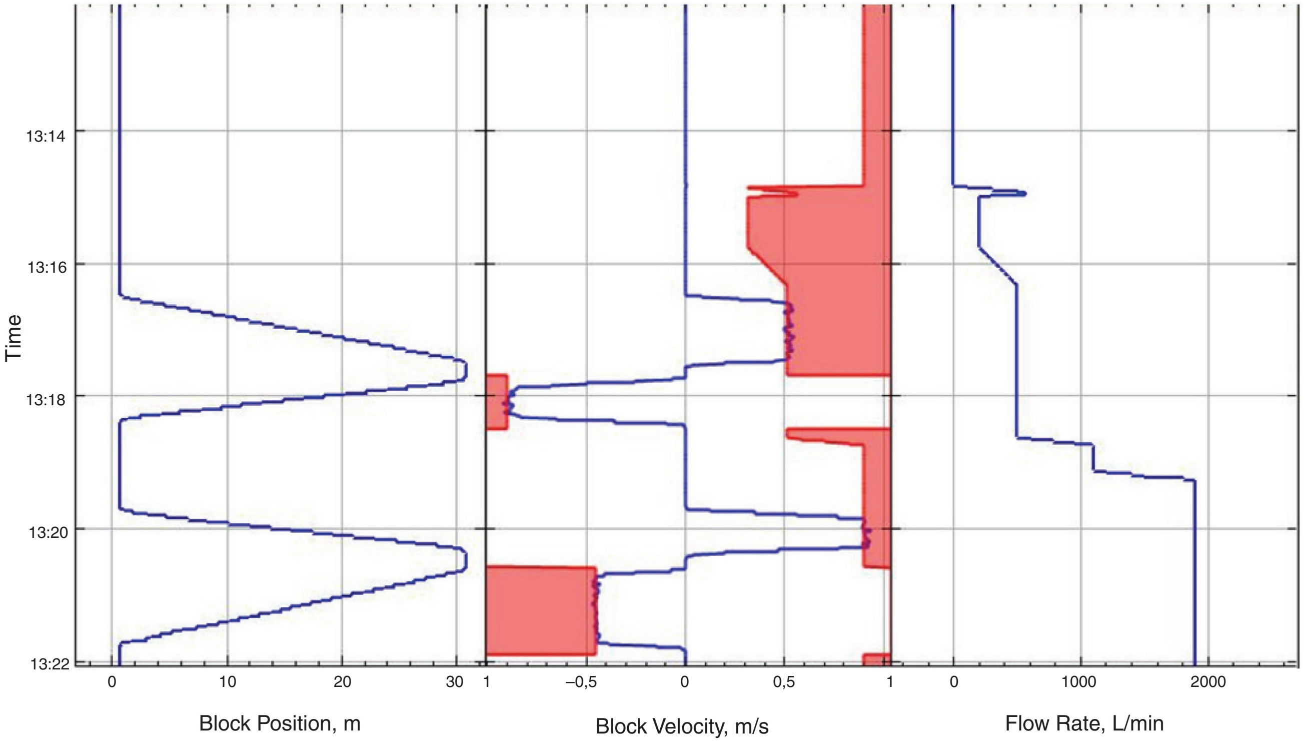
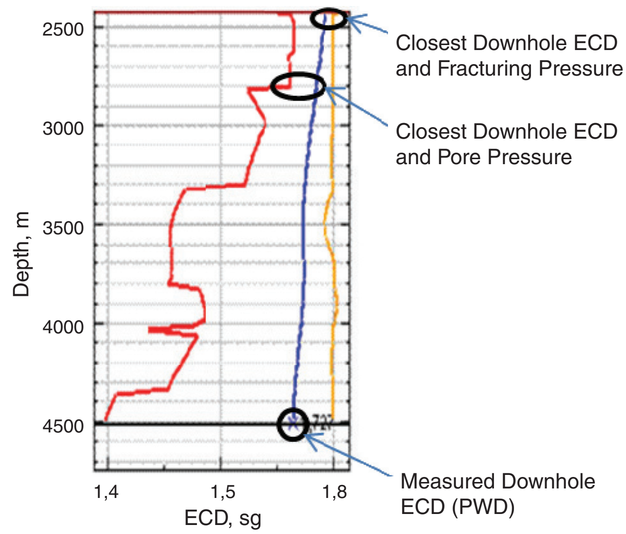


Fig. 9—Example showing the effect of pump rates on tripping velocity. The same stand is reamed up and down while ramping up the mud pumps. One can see that the upward velocity is limited at low pump rates, whereas the downward velocity is limited at high pump rates. These data have been generated using a replica of the offshore drilling-control system in a virtual rig environment.



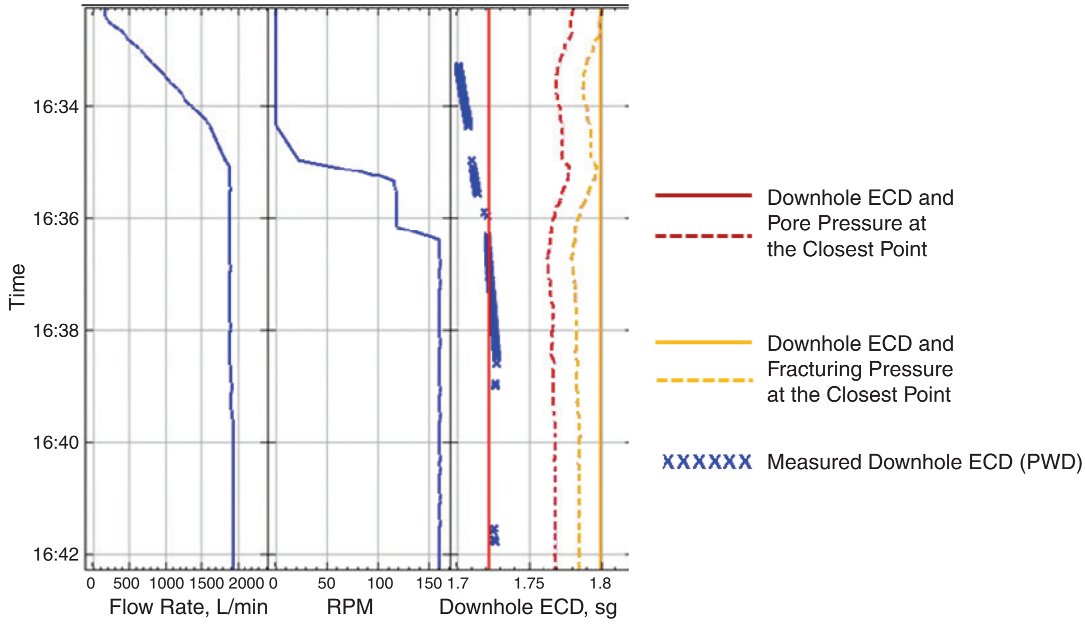


Fig. 10—These pictures show the importance of checking the downhole pressure along the entire openhole section and not only at the bit depth. In the chosen example, there is a narrow geopressure window [from 2400 to 2800 m measured depth (MD)] just below the casing shoe (at 2400 m MD). The top graph shows the calculated downhole ECD in the annulus and the reported downhole ECD measured by the downhole pressure sub (blue marker) at time 16:38:15. In the bottom graph (time based) are reported the measured downhole ECD (blue marker) as well as the downhole ECD and pore pressure (red dotted and solid lines) at the depth where those values are the closest and downhole ECD and fracturing pressure (yellow dotted and solid lines) at the depth where those values are the closest. One can see the effect of starting the mud pumps and the topdrive (from 16:32:30 to 16:36:20) on the downhole-ECD margins. In this case, the margins at the bit depth, where the downhole-pressure-sub measurements are made, are fairly large and, therefore, are not the limiting factors.

done by the drilling engineer using a dedicated user interface. The relevant inputs are

- Casing program
- Drillstring description (drillpipes and BHA)
- Drilling-fluids description
- Planned-trajectory description
- Geopressures gradients (pore pressures, fracturing pressure, collapse pressure)
- Geothermal properties
- Rig description (e.g., drawworks characteristics and mud-pumps characteristics)

Detailed Operation Procedure. In addition to the axial-velocity limits based on the geopressure window, the system also takes into account user-defined velocity limitations. Those limits are usually estimated during the planning stage by the engineering team and are available to the driller by means of the detailed operation procedures (DOPs). The drilling engineer can enter the DOPs into the system through a dedicated user interface. More precisely, a DOP here is an operation description and an associated axial-velocity limit. The operation description consists of

- The name of the operation
- The depth range for the operation [in measured depth (MD)]
- The type of operation (drilling or tripping)
- The circulation rate for the operation
- The rotational frequency for the operation
- The axial-movement direction

On the basis of that information, the system can recognize what is the ongoing drilling operation and apply the corresponding velocity limit. The system will differentiate between tripping and drilling operations by looking at the on-/off-bottom status: If there is more than one stand length between the bit depth and the total depth, then the string is off-bottom and the system is in tripping mode; otherwise, it is in drilling mode.

Configuration of Trip Heights and Activation of Axial-Velocity Limits and Overriding. Configuring trip height consists of specifying lower and upper heights. This can be achieved directly from the drilling workstation: The driller has only to move the block at the desired height and then, by pressing a key, set the corresponding height (lower or upper) to the current block position. The driller can activate and deactivate the trip heights by using a single key in the drilling workstation.

Activation/deactivation of axial-velocity limits is also available at the drilling workstation by pressing the corresponding key. However, in the case of an emergency, the driller may have to bypass the axial limits imposed by the system, and he or she may not have the time to navigate to the relevant keypad to turn the axial-velocity control off. This is why it is possible to override the limits by using the drawworks joystick on the right. When the axial-velocity-limits system is activated, the drawworks joystick has three operating modes: creep speed (joystick on the left), limited speed (center joystick), and nonlimited speed (joystick on the right).

Configuration of Hookload and Torque Margins, Activation, and Overriding. The system computes automatically the maximum and minimum allowable hookloads (corresponding to the maximum overpull and the minimum set-down weight) and the maximum allowable torque. However, the driller can specify the margins that he or she wants to use. The driller can manipulate markers displayed on the hookload and torque gauges of the drilling workstation to specify allowable overpull, set-down weight, and extra torque. The system then updates the maximum allowable hookload and surface torque on the basis of the current drilling conditions (axial movement, circulation rate, pipe rotation).

As for the axial-velocity control, the driller can activate or deactivate this functionality directly with the corresponding key in the drilling workstation and override those limits by using the drawworks joystick on the right.

Friction-Test Configuration, Activation, and Emergency Stop; Results From Friction Test. Some configuration parameters are required to perform automatic friction tests: sequence distance, pick-up velocity, rotation off-bottom rotational speed, rotation off-bottom duration, and slackoff velocity. The driller can enter the desired values directly into the drilling workstation. He or she can start the friction-test sequence by pressing a key on the relevant keypad, and the sequence can be interrupted at any time by nudging the drawworks joystick to the right.

Once the friction test has been performed, the relevant measurements (average hookload during pickup, average surface torque during rotation off-bottom, average hookload during slackoff) are available on a dedicated window in the drilling workstation, which makes it easier for the driller to report the correct values to the engineers in charge of hookload and torque monitoring. Note that, because they are available on the supervisory-control-and-data-acquisition network, the friction-test results also can be distributed automatically to onshore operation centers, for example.

Autoreciprocation Configuration, Activation, and Emergency Stop. As with the friction test, the necessary parameters for the autoreciprocation are entered by the driller into the drilling workstation. Those parameters are sequence distance, back-reaming axial velocity, back-reaming rotational speed, off-bottom rotational speed, off-bottom rotation duration, reaming flow-rate reduction, reaming axial velocity, and reaming rotational speed. Similarly, the sequence can be interrupted by a simple nudge to the right on the drawworks joystick.

Practical Experience

In this section, some of the practical experience gained from the pilot testing of the system in early 2008 and 2009 will be discussed. Both pilot tests took place at a fixed installation on the Norwegian continental shelf in the North Sea.

The first pilot test, in 2008, took place during the drilling of a 12¼-in. section. The system was active during running in hole (RIH) and pulling out of hole (POOH) of two assemblies before running the drilling assembly. (Total depth at this time was approximately 1000 m.) As the drillers became increasingly confident in the system, they started to use the preset lower trip height actively while RIH. Because the connection is always at the same position, adjustment of the roughneck is not necessary. Such functionality saves time during RIH operations. When running the drilling assembly, the system was not active for the first 650 m because the crew had to pick up singles. When the drilling of the section was finished, the system started receiving erroneous input from the sensor measuring the temperature of the injected fluid. The reason for the erroneous measurements was that a different tank was used as the active pit and, furthermore, the pit level in the tank containing the temperature sensor was below the sensor position. Because of the problems with the temperature measurement, it was decided to deactivate the system during POOH after drilling because the calculations could not be trusted. Simulations performed after the test showed that this was a correct decision because there would have been a strong reduction in acceleration if the correct temperature had been used.

During the first pilot, 20 out of 23 friction tests were performed automatically. (Autoreciprocation was not implemented at the time.) The first test was performed manually because the BHA was still inside the casing window. The remaining two manual tests were related to crew change. A comparison between the manually noted average values during the friction tests and the systematically computed values revealed an error in the manually reported values and a difference in hookload readings between 1 and 2.5%. The torque readings had a more pronounced difference of between 12 and 15%.

In 2009, an upgraded version of the system was installed at the same platform (Larsen et al. 2010). This time, the pilot test was performed on three wells. The first well was a 12¼- and an 8½-in. section, and the second and third well were 6×7-in. sections (where a bicenter bit was used).

The axial-velocity limits (with and without circulation) were tested extensively throughout the pilot and were used for both RIH and POOH operations. However, at no time during the pilot did the actual velocity used by the drillers approach the calculated limits; therefore, the system did not enforce any reduction of velocity **(Fig. 11).** As a side note, this indicates that there could be hidden time savings to be achieved using such a system. Automated friction tests and reciprocation were performed several times, mainly during drilling of the 12¼-in. section, which was the longest of the four sections. Before and during the test, user-friendliness issues were discussed and improvements were made. Some of the improvements have not yet been tested, one of those being the possibility to stop at a given connection height.

Functionality that has not been tested offshore is maximum overpull and set-down weight, and maximum torque. These functionalities were not characterized as tested because these situations never occurred during drilling. Further, extensions related to axial-velocity control under the influence of heave have not been tested because it was not implemented at the time of the test. This functionality was requested by several drillers and has already been implemented in an upgraded version of the system.

With correct input and fully calibrated models, forward simulations, friction estimations, and calculations of expected hookload and torque gave very good results. The pilot tests also revealed that some of the sensor readings become critical because the model calculations depend strongly on these measurements (Cayeux et al. 2009). In particular, the temperature and mud density of the injected fluid are important input parameters, which earlier were used only for trending. The main problem with the mud density is that the measurement is biased and the bias is not constant. The challenge with the temperature reading was that only the most frequently used pit contained the temperature sensor and the pit level may sink below the sensor position. The bit depth is another important parameter that is calculated by the drilling-control system. On two occasions, this parameter froze, which caused trouble

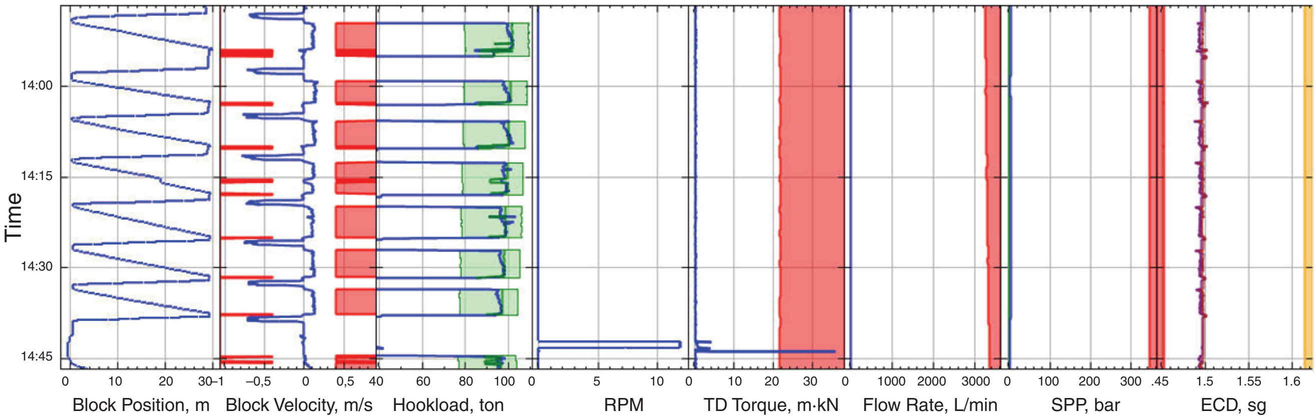


Fig. 11—Example of a POOH with a 12¼-in. drillstring. These data were recorded during an offshore test in the North Sea. Note that the driller was using a much lower axial velocity than the maximum tolerable limits calculated by the system. The red semitransparent areas represent the boundary limits. The green semitransparent areas depict the expected values as predicted by the system (including an estimation of the uncertainty in the calculations). The brown and purple lines in the downhole-ECD tracks are the calculated downhole ECD at the closest proximity to, respectively, the pore-pressure gradient and fracturing-pressure gradient.

for the calculation modules. Downhole data, such as survey measurements and downhole ECD, were not transmitted properly to the drilling-control system and, therefore, were not available. Some of the problems that still remain are the manually controlled events, such as management of the valves controlling which pit is active and dropping balls to activate or deactivate downhole tools such as circulation subs and hole openers. Related to this is the problem with identification of the mud that is currently being circulated. Another problem that remains is the use of pumps for purposes other than circulation. This could potentially lead to problems because the wrong set of limits could be used for control. During the test, personnel from the International Research Institute of Stavanger (IRIS) and National Oilwell Varco (NOV) were present offshore to assure the quality of the input. To avoid such offshore support in the future, the availability of the critical measurements mentioned earlier must be guaranteed.

Throughout the tests, there have been no incidents causing downtime or damage to equipment or personnel related to the use of this system. The involved drillers have developed a positive attitude toward the technology and have provided several suggestions to improve the user friendliness.

New work procedures must be implemented before the system can be used on a daily basis. The models that perform hydraulic and mechanical calculations rely on a comprehensive set of input data, which should be quality assured. It is also important to know how to react if an emergency occurs and to have the possibility to override the system if required; therefore, the training of personnel should be prioritized. IRIS has already developed a virtual rig simulator, which is intended to be used for testing technology related to automated drilling. The possibility of testing all the modules in a realistic environment has already proved a great advantage. Programmable-logic controllers that contain machine-control algorithms identical to the one installed offshore were installed and tested in combination with a replica of the offshore drilling-control system. It is important for the personnel involved to understand that a malfunction could endanger both people and installations at the site. Training of the personnel in the virtual rig environment proved to be important for the acceptance of the system offshore. If the support is to be moved onshore, data-security issues should be considered.

Conclusions

A novel drilling-control system that applies continuously updated safeguards for operating the drilling machinery to account for the tolerances of the openhole formations has been developed and tested on a fixed platform offshore Norway. All tested functionalities were successful during the pilot test. The drillers involved in the testing have been positive and have even requested more functions, which are under development and soon will be ready for testing. Even though the technology has been shown to be very reliable under the test period, experience has exposed that the key vulnerability of such a system is the access to high-precision measurements. The aviation industry has embraced the use of automation for many years and has worked out principles for providing a guarantee on the measurements made on an airplane. Similar work needs to be performed for drilling rigs to fulfill the goal of implementing advanced automation systems.

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