Well control modeling is effective tool to manage risk and make critical decisions

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WELL CONTROL MODELING is becoming a very effective tool for managing risks and making critical decisions. It can be used to evaluate a wide range of well control scenarios as well as develop actions to reduce risks and make contingency provisions. The stakes are especially high in expensive and critical projects such as ultra deepwater or deep gas drilling.

In well planning, it is used for evaluating well designs by developing circulating kick tolerance based on fracture gradient, gas handling capacity of rig equipment, or other specified limits. In operations, it is used to support well control decisions with updated kick tolerance when changes occur in fracture gradient, mud weight, or size and depth of hole and casing.

Besides simulating standard methods to design the kill when a kick occurs, it also handles special operations such as extended shut in, mid-kill interruptions and changes, concurrent kill and volumetric kill. The model is based on complete transient two phase flow, with results that are displayed in simple graphics that are easy to understand and use in the field.

THE SIMULATOR

The simulator is a fully time transient, two phase flow model that provides a number of technology improvements over conventional steady state models. It can simulate and track the actual full behavior of a kick, starting with influx of the kick, flow check, shut in, the subsequent kill and venting of gas on the surface. Instead of just seeing the results, as in the case of a steady state model, the entire kick and kill process can be visualized.

Besides the standard driller's method or wait and weight circulations, a transient simulator of this kind allows changes in operating conditions to be made at any point during the well control process. It can handle special procedures such as extended shut in of a kick, changing mud weight, pump rate, taking additional influx or other interruptions during a kill.

There are also other useful features made possible by this kind of simulation.

One feature is Two Phase versus Single Bubble Modeling. A single bubble model assumes that the kick influx occurs as a single phase and remains so as it is circulated up the wellbore. This tends to produce conservative results, which is usually preferable. However, for deep and or high pressure wells, the results can sometimes be too conservative and not realistic, making it almost impossible to design a well. A multiphase model provides results that are more realistic, which is especially important for deep and high pressured wells.

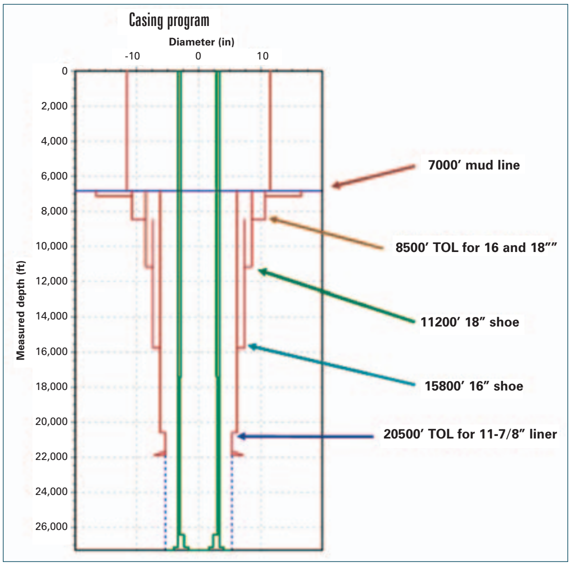

Figure 1—Well bore schematic and observation points.

For drilling in deep water, say over 1,000 ft, Choke Line Friction Pressure (CLFP) limit in a long choke line through the water column can sometimes be high enough to effectively override the effect of the adjustable choke, as often happens when a gas kick is circulated close to the surface. In order to maintain the proper pressures, it will then be necessary to use an additional choke or kill line, slow down the kill pumping rate, stop the kill to bleed down the pressure, or take all three of these actions. A transient simulation allows the detection of such occurrences. The simulation can be paused to execute one or more of the above responses, and continuation of the simulation will then enable the effects of these actions to be evaluated.

The simulation includes effects of pressure drop in a gas flaring system, including the separator, flare line and mud leg. If the gas flaring rate exceeds system capacity, the simulation will indicate that the mud leg has been blown. Usual response options are slowing the pump rate, shutting down the pump to bleed gas, or bypassing the separator. The simulation can be paused to implement one or more of these actions, and continuation of the simulation will allow evaluating the effects of such actions.

The simulator used for modeling in this article is the "kick" program from the "drillbench" suite of drilling simulation software. It was developed by Norway's **Rogaland Research Institute** and licensed through **Scandpower Petroleum Technology**. It runs on Windows desk top and lap top computers.

The simulations can be used to evaluate well design by modeling and developing circulating kick tolerance, based on both casing shoe fracture gradient as well as gas handling capacity of surface equipment. Results for each hole section can be summarized in simple charts for use at the office or in the field. Well control risks are thus quantified and mitigated by defining kick handling limits for each hole section, and conducting drilling operations to stay within these limits.

The simulations support well control decisions with updated kick tolerance charts and simulations when changes occur in shoe fracture gradient, mud weight range, casing or hole sizes and depths. Such updates provide real time assessment of well control risks.

The simulations provide evaluation of alternatives either for contingency planning or in response to an actual well control situation. Examples include near-real time simulation of kick circulation, involving changing mud weight, pump rate and other conditions during a kill. Other variations also include changing sizes of choke, choke line and gas separator sizes, extended shut in before or during a kill, and volumetric kill. These simulations allow effective near-real time evaluation of contingency options for handling well control events.

WELL PLAN SUMMARY

The following is a typical summary of well control evaluation for a well plan. The project involves a 27,000 ft well to be drilled in a water depth of some 7,000 ft. Simulations were performed to evaluate circulating kick tolerances based on formation fracture strength at the casing shoe for critical well sections below 11,180 ft measured depth (MD). Although formation integrity test (FIT) is used in this case, predicted fracture gradient (FG) or leak off test (LOT) value can also be used.

The four sections consists of the 16x20-in., 14 ¾x17 ½-in., 12 ¼x14 ¾-in., and 10 ⅝-in. holes, all of which are to be drilled with synthetic base mud (SBM). Based on FIT values, two hole sections are identified as having kick tolerances below the common practice minimum of 0.5 pound per gallon (ppg) while drilling with maximum mud weight at total depth (TD) of the section. These are the 16x20-in. and 14 ¾x17 ½-in. holes, where minimum shut in kick tolerances are 0.22 and 0.31 ppg, respectively.

Overall results for the well show that, for kick volumes of up to 85 bbl in size, kick tolerance ranges from 0.2 to 2.5 ppg in magnitude. Choke pressure seen in these containable kicks ranged up to 3,200 psi and surface gas rate ranged up to 3.9 mmcfd at kill rates of up to 300 gpm, with a pit volume gas expansion of up to 85 bbl. Casing pressure increased up to 3,000 psi above mud column hydrostatic while circulating out containable kicks with a mud weight of 12.7 ppg in the 12 ¼x14 ¾-in. interval.

It should be noted that these maximum values result from containable kicks within the volume range investigated. Larger volume kicks and kicks that break down the casing shoes can result in substantially higher pressures at the surface and in the wellbore, larger expansion pit volumes and higher surface gas rates. These can only be evaluated with additional modeling on a case by case basis.

RESULTS

Simulations were run for the maximum planned depth of each hole interval. Driller's Method is used to circulate the kicks in order to provide conservative results. The four intervals involved were:

- 16x20-in. hole drilled below 18-in. casing from 11,200 ft to 15,800 ft;
- 14 ¾x17 ½-in. hole drilled below 16-in. liner from 15,800 ft to 20,800 ft;
- 12 ¼x14 ¾-in. hole drilled below 13 ⅝-in. casing from 20,800 ft to 21,800 ft MD;
- 10 ⅝-in. hole drilled below 11 ⅞-in. liner from 21,800 ft to 27,000 ft.

Figure 1 shows the wellbore schematic, as well as locations of the "observations points" where wellbore pressure is displayed. Up to five observation points can be designated for each simulation, which are typically chosen to be at the mud line, tops of cement, tops of liners or other points of interest.

KICK TOLERANCE

Kick tolerance is simulated for each hole section to evaluate the well's ability to contain the shut in and circulation of kicks without exceeding formation fracture pressure at the respective casing shoe of the interval. Those combinations above the curve will result in exceeding fracture pressure at some point in the kill process. Each plot involves the minimum and maximum mud weights planned for the hole interval. The data points on these curves are also labeled with the equivalent bottom hole pore pressure for each point.

Note that, for any given hole section, while kick tolerance is always higher for a lighter mud weight, the equivalent pore pressure of the corresponding contain-

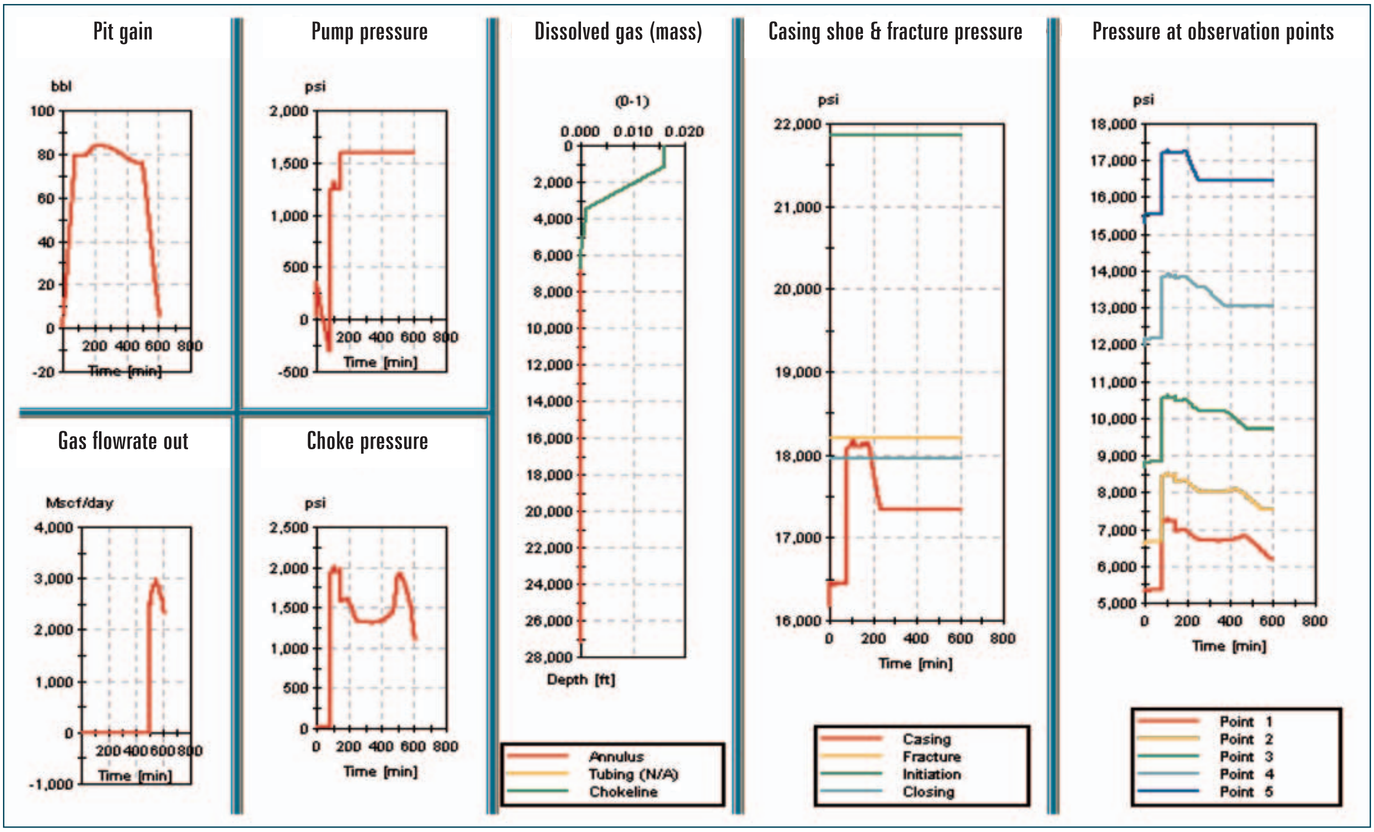

Figure 2—Typical time history graphic output, 80 bbl x 0.6 ppg kick with 15.0 ppg mud.

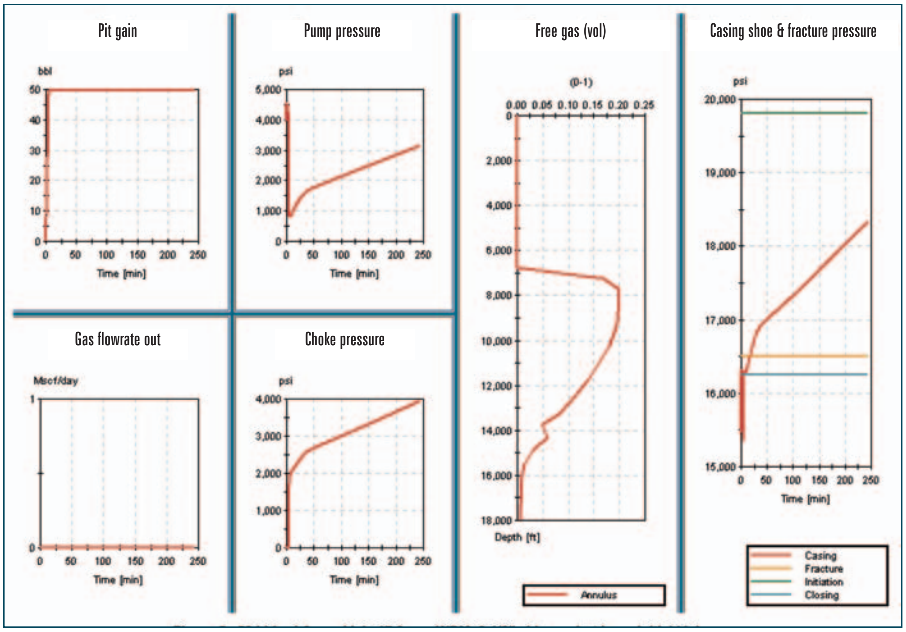

Figure 3—50 bbl x 1.0 ppg kick, 17.0 ppg WBM, 6 ½-in., 4 hour shut in on initial kick.

able kick is lower or equal to that for the higher mud weight.

In other words, a gain in kick tolerance from using a lower mud weight actually results in a lower, or at best the same, pore pressure that can be handled.

Kick volume range for these simulations have been limited to about 80 bbl, since this should cover the range of kicks normally expected when drilling operations are conducted by reasonably well trained personnel.

Following is a summary of the range of containable kicks as determined from the simulations.

Time Histories and Press at observation points. Figure 2 contains a typical time history plot. Besides wellbore pressure at the observation points, other parameters displayed in these plots include casing and drill pipe pressures, pit volumes and surface gas rates. It also shows pressure at the casing shoe and how it compares with formation fracture (FIT) pressure. These figures represent typical time history illustrations of simulated well kicks from time of influx to gas at surface.

Casing Pressure at Observation Points. Figure 4 also contains time history plots that show maximum wellbore pressure at the designated observation points. These observation points are typically chosen at the mud line, tops of cement, tops of liners or other points of interest, where such pressure information can be critical in the evaluation of casing burst design.

Separator and flare lines. The simulator provides a warning whenever the rate of gas and mud discharge results in a back pressure that would blow the specified mud leg column height in the separator system. Specifications used for the separator system in this report are based on typical values for a deep water offshore drilling operation. The system appears to be more than adequate to handle the gas kicks at the simulated kill rates of up to 300 gpm, as the warning was not tripped by any of the simulation runs.

DRILLING OPERATIONS

The kick tolerances are applicable only to the specified mud weight and well scenarios. If there are changes in hole or casing sizes, fracture gradient, FIT results, well depth, shoe setting depth or mud weight, then additional model runs will be needed to develop new or at least updated sets of kick tolerance curves.

Note that the model indicates a shoe failure even if the wellbore pressure is just a few psi above the fracture pressure. Since actual fracture pressures are not usually known to this degree of accuracy, this should be taken into consideration when interpreting the plot. If the well encounters a kick combination that is close to the curve, a model run can be made based on specific and updated parameters. Output from such a run would be similar to those in Figure 4, and would provide a more accurate evaluation of well control conditions. Once the model has been set up in the well planning phase, any of the above updates can be provided in a matter of minutes. This near real time information can be very helpful for managing a drilling operation, especially for exploratory wells which often involve significant uncertainties in such well parameters.

WELL CONTROL OPERATIONS

Beyond the conventional Driller's Method and Wait and Weight Method for circulating out a kick, these simulations can also be used to evaluate a number of special well control operations, as described in the examples below, where water based mud (WBM) is used in order to show the effects of rapid gas migration:

Extended shut in. This demonstrates effects of rapid migration up the hole for a gas kick in water based mud. As shown in Figure 3, after shutting in for 4 hours

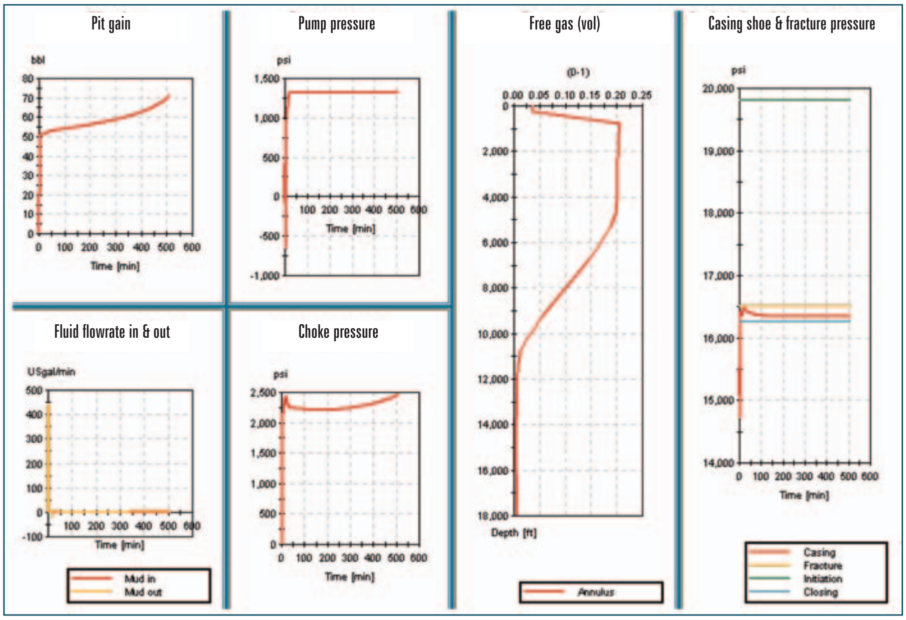

Figure 4—50 bbl x 1.0 ppg kick, 17.0 ppg WBM, 6 ½-in., volumetric method to bleed gas to surface while maintaining constant drill pipe pressure.

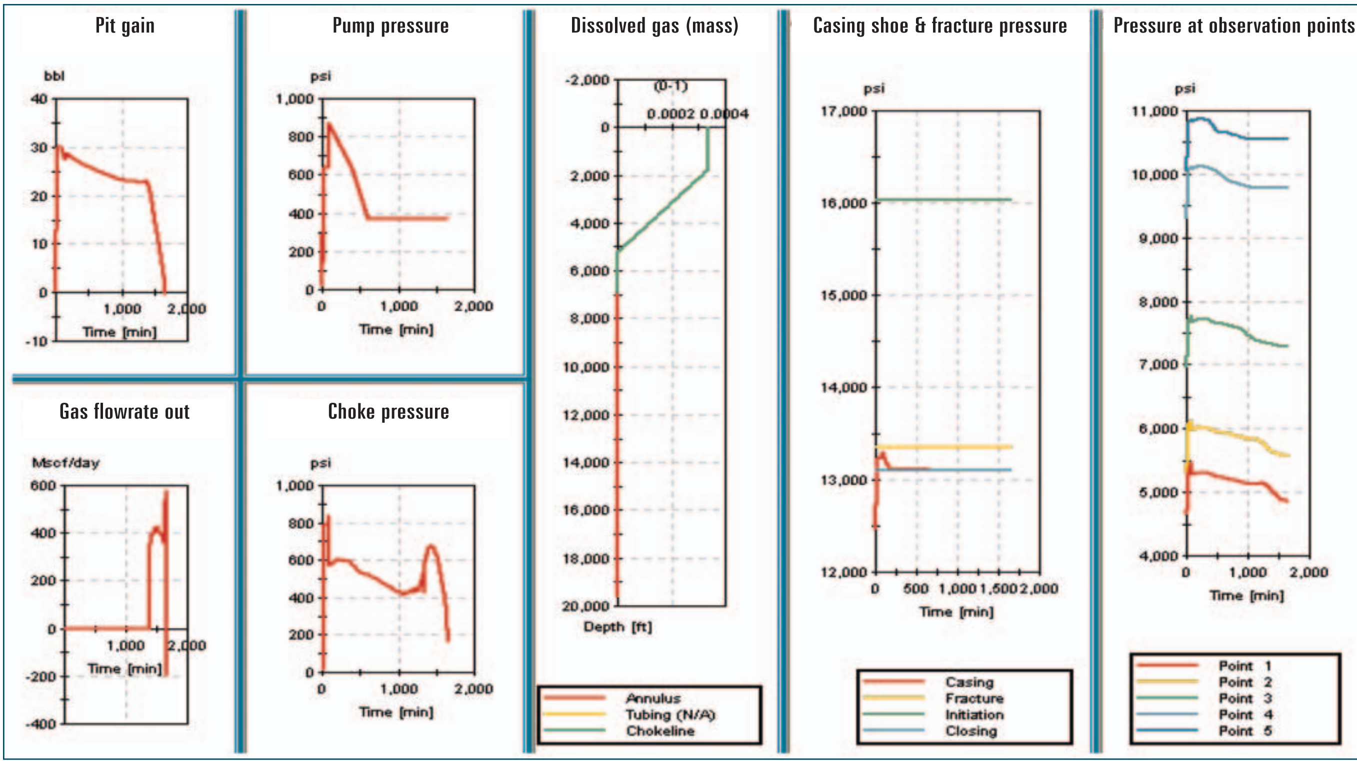

Figure 5—30 bbl x 0.5 ppg kick, 12.8 ppg SBM, 13.3 ppg KWM, 1.0 bpm kill rate, 10 5/8-in. hole at 19600' TD, 11 7/8-in. liner at 15,145-18,900 ft with 13.6 ppg FG. The well is in 7,000 ft water depth.

without bleeding the annulus, the gas has migrated to 7,000 ft (from an initial 13,000 ft), and wellhead pressure rose from the initial shut in value of 2,000 psi to 4,000 psi. Pressure at the shoe, which was initially 200 psi below fracture, exceeded it after a shut in of only 18 minutes.

Volumetric Kill. In this run, the same kick was kept shut in. As shown in Figure 4, this time the gas was allowed to migrate, and was brought to the surface using the volumetric kill method, in which annulus pressure was bled off to maintain constant drill pipe pressure. Pressure at the casing shoe was kept below fracture pressure during the kill process.

RISK MANAGEMENT

Following are three recent cases in which application of well control simulation had a significant impact on risk mitigation decisions.

Casing burst design. A 13,000 ft intermediate string of 13 5/8-in. casing was originally planned for a 20,000 ft well. Burst design for the casing was evaluated based on simulated pressures at the observation points similar to those shown in Figure 2. Results indicated that the burst design was too marginal to meet the company's design criteria when casing wear was taken into account. The design was changed to a string of 14-in. casing to provide thicker wall pipe for drilling the intervals below.

Circulate or bullhead? An operator took a 33 bbl x 0.5 ppg kick while drilling 10 5/8-in. hole with 12.8 ppg synthetic oil based mud (SBM) at 19,600 ft TD. The well is in 7,000 ft of water and 11 7/8-in. liner is set at 15,145 ft-18,900 ft, where the shoe was tested to leak off at 13.6 ppg EMW. Shut in casing (choke) pressure (SICP) of 800 psi was within 100 psi of maximum allowable without breaking down the shoe. There was a concern of increasing pressure on the shoe due to gas expansion if the kick was to be circulated out conventionally. This concern led to an Initial decision to bullhead the kick back into the formation. The model was already previously set up for working on planning of this well, so a near-real time simulation was quickly run for circulating out this kick. The simulation showed that pressure at the shoe decreases as the kick is circulated out. Bull heading would involve additional friction that most likely would result in a break down of the shoe. The kick was subsequently circulated out successfully using the "wait and weight" method, with pressure profiles as shown in Figure 5.

Insurance premium. A number of underwriters for well control insurance are now requiring some of their clients to obtain well control evaluation using this type of simulation. This helps to lower the risk exposure for the underwriters, who often in turn reduce the insurance premiums for the operators that comply with this evaluation. In a recent case, one company was reported to have saved over $120,000 in well control insurance premiums in the course of drilling five wells.

CONCLUSIONS

Much of petroleum exploration and production is about risk management, and well control is an ever present and potentially costly issue. Well control simulation is a useful tool for helping to manage these risks. When applied to well planning, it serves to identify potential well control problems and mitigate these risks by developing and optimizing well design. It can also be applied to evaluate special well control operations and thus provide contingency provisions in the event that such problems do occur.

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