Understanding pressure is key to avoiding well control issues in Duri steam flood

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WITH OVER 7,000 drilled wells, the Duri, Indonesia Steam Flood (DSF) is the largest steam flood oilfield in the world. The two producing sands, Rindu and Pertama/Kedua, are at shallow depths of approximately 300-800 ft. These sands are injected with 375° F to 450° F steams at 0.7 psi/ft with an average daily 768 BCWE through 1,370 injection wells.

There have been four steam related blowouts during the five year period of 1999-2003 including the loss of the drilling rig in one incident. Understanding injector steam pressures has proven to be a key to safely drill in fill wells.

Drilling in an active steam flood field such as DSF poses many challenges. Casing shoes are often set in relatively unconsolidated or weak formations.

Additionally, shallow non-producing formations may become charged with steam percolating from injection depth along non-sealing faults or via conduits provided by incomplete or failed zonal isolation in adjacent wells.

These charged formation pressures need to be balanced against fracture gradients and mud weights. Compounding the problem is potential lost circulation at the higher mud weights required to control steam pressures. Well control is also complicated by the high steam temperatures.

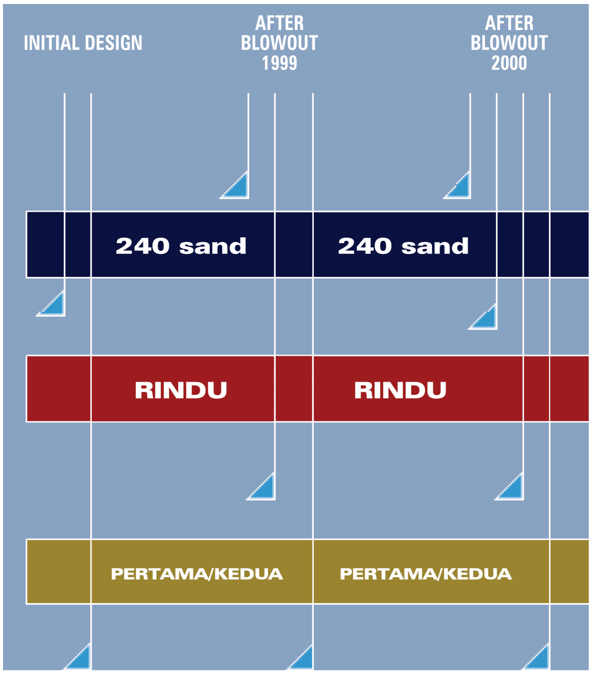
A number of indicators are used to evaluate the potential of shallow steam hazards and identify the extent and impact of injected steam on new drills.

These indicators include flowing wellhead temperature, fiber optic surveys, workover data from adjacent wells, active and shut-in injector pressures, production well casing pressure surveys and 3D seismic.

Formation pressure logs assist in verifying and validating projected reservoir pressure and are used to further understand and develop pressure profiles for subsequent wells.

The complex nature of steam flooding requires that all indicators be evaluated on an individual basis and as a part of the whole body of data since any single data point may result in error. The primary benefit of the evaluation process is the determination if an injector should be shut-in prior to safely allow drilling an adjacent well. A secondary benefit of the process accrues through improved heat management by minimizing shut-in where possible.

Use of these processes to identify pressure gradients and safe mud weight ranges allowed eight replacement producer wells to be drilled in 2004 without a single steam kick incident. The next challenge is to drill a well without shutting in surrounding injectors.



The casing program and design depends upon the identified steam activity, assessed risk and the well's total depth.

DURI STEAM FLOOD OVERVIEW

The Duri steam flood project, located in Riau Province of Central Sumatra, Indonesia, is the largest thermal enhanced oil recovery project in the world. The field is approximately 18 km long by 8 km wide with a developable area of about 20,000 acres. Structurally, Duri field is a faulted-asymmetric anticline with degree of complexity increasing westward near the Sebanga fault that bonds the field.

The field was discovered in 1941, but was not put on production until 1958 with the completion of a pipeline from Duri to the port of Dumai. Field primary production peaked at 65,000 barrels of oil a day in the mid 1960s and declined to 30,000 barrels a day in the early 1980s.

It was clear that unless new technology could be applied, the Duri field's days were numbered. Tests were run, results evaluated, and a steam flood pilot project begun.

Today, Duri is injecting about 1 MMBCWEPD of steam and producing about 200,000 BOPD with 4,142 producer wells. In the coming years new development areas will add to the well count as will development of the shallower and deeper sands in the existing areas. Furthermore, an aggressive in fill drilling campaign is also underway.

UNDERSTANDING PRESSURE

Average reservoir pressure gradient prior to initiating the steam flood was about 0.2 psi/ft to 0.3 psi/ft. Subsequent steam injection pressure of 0.70 psi/ft increased the reservoir pressures above original.

The injection pressure is targeted below the shale fracture pressure of about 0.75 psi/ft to avoid creating conduits for escaping steam.

Unfortunately, as history has proven, steam can escape from the target zone into untargeted sands without fracturing the confining shale. Major contributing factors include non-sealing faults, poor or deteriorated cement and lack of zonal isolation.

At shallow depths, even a small miscalculation of the actual formation pressure may lead to well control events, bringing hydrocarbons and high temperature steam immediately to the surface.

A well kick, even if quickly shut-in, could result in a broached shoe and surface eruptions or an underground blowout charging shallow permeable sands with high pressure steam.

Steam pressure contributing to the influx may be reduced over time by killing adjacent injector wells. Unfortunately, injector killing is a last resort since doing so will disrupt the reservoir heat management and reduce production of surrounding wells.

A comprehensive well-by-well review is required to avoid these potential scenarios. The objective of this review is simple: to understand and use formation pressures to select the appropriate mud weight to safely drill in steamed environments without a well control situation. This selected mud weight should balance the potential for lost circulation against the steam pressure.

Understanding the subsurface risks for a drilling program in an active steam flood project can be done with a variety of static and dynamic information.

Duri steam flood (DSF) risks are typically evaluated by reviewing reservoir characterization, combining studies of steam shape prediction and review of offset well conditions.

Every available method relies on certain assumptions, creating uncertainty about the study outcome. Several methods were integrated in an attempt to reduce risk uncertainty.

PRE-DRILLING ASSESSMENT

Duri reservoirs occur in sands of the Duri and Bekasap formations of early Miocene age at depths from about 300 ft to about 750 ft at the water contact and are divided into four groups: 140 ft and 240 ft sands; Rindu; Pertama-Kedua (PK); and Baji-Jaga-Dalam.

The Duri steam flood project has exploited these multilayer sands for about the same duration. The uppermost sands, the 140 ft and 240 ft, are not produced except for limited testing purposes. The Rindu is the shallowest interval produced in Duri.

The main steam drive intervals in DSF are the PK sands. Together they account for over two-thirds of all oil in place. The deepest intervals are the Baji, Jaga, and Dalam sands but the oil accumulation in these sands is limited to crestal portions of the south end of the field.

The two main producing sands, Rindu and PK are at depths of approximately 300-800 ft and are injected with 375° F to 450° F steams at 0.7 psi/ft with an average daily 768 BCWE through 1,370 injection wells. Production patterns generally are inverted 5 spot, inverted 7 spot, or inverted 9 spot.

Steam breakthrough is an important transition point when discussing thermal recovery mechanisms. The DSF operational definition of breakthrough is when pattern average wellhead temperatures rapidly rise from about 200°F up to approximately 250°F and then plateau at this higher temperature accompanied by a decline in oil steam ratio or oil production.

Before steam breakthrough, the predominant drive mechanisms are the large pressurization of the reservoir and large horizontal viscous forces. Production from steam drive occurs mostly as a push from the steam injection until steam breakthrough.

Average reservoir pressure increases by 150-200 psi (50-100%) during the start up of an area.

After a few months of injection, production rapidly increases to nearly five times the pre-steam rates. Average horizontal pressure gradients across the patterns are about 1 psi/ft before steam breakthrough.

After steam breakthrough, average horizontal pressure gradients decrease to below about 0.2 psi/ft and gravity drainage predominates. Because of high steam mobility and low oil saturation in a steam zone, the breakthrough effectively prevents any further "pushing" of oil through that layer.

Production losses from the breakthrough layers are, however, partially offset by production gains from hot plate heating of adjacent layers.

Review of structure mapping is done in detail. Estimation of the depth of the top sand is provided for casing design purposes. 3D seismic is analyzed using edge attribute data combined with calculation of a faults shale gauge ratio to determine if a fault is sealing or not.

The potential size and shape of steam zones existence is defined for every zone by combining seismic anomalies with a calculation of steam zone size using Neumann's equation and actual data.

The heated area is then shaped based on temperature data (well head temperature and temperature surveys in observation and producing wells).

Injector-producer communication is identified by examining pattern based historical performance and is used to prioritize injectors most likely to affect drilling.

Offset well history is reviewed to identify issues that may affect drilling execution. Relevant data includes offset drilled wells, adjacent workover details such as kill fluid weight, casing leak squeeze information, cement bond log results, etc.

Reservoir pressure surveys taken from adjacent shut-in wells are plotted to gain a sense of pressure that may be faced.

The outcomes of the various techniques are compared for consistency and combined by assigning weighting factors to provide final determination of subsurface risks for a given drilling program. In addition, the assessment results are used to develop a risk based contingency plan.

Casing program and design depends on the identified steam activity, assessed risk and the well TD.

For example, in areas where there is no steam injection into the Rindu formation and without identified shallow steam hazards, the 240 ft sand and Rindu sand can be covered in one single string.

If steam exists, two casing strings will be used to prevent the potential of Rindu steam pressurizing the shallower 240 ft sand.

To compound the problem, both the Rindu and the deeper PK are prone to severe lost circulation. This can lead to such complications as lost circulation in the PK allowing a Rindu steam kick or steam cross-flow from the PK into the Rindu or steam flow from either the Rindu or PK into the 240 ft sand.

DRILLING PHASE

A comprehensive drilling program for each individual well is then developed. This program incorporates the risk of assessed or calculated subsurface steam hazard into the drilling, casing and completion programs.

The well planning includes site preparation, drilling procedure, and steam well control procedures. All potential events and drilling hazards are communicated to the drilling crew and responses are honed through BOP and pit drills.

SITE PREPARATION

Site preparation and assessment is critical to proper planning. Assess the well site to determine if a simultaneous operation (SIMOPS) is applicable.

Data suggests that continuing to produce while drilling another well on the same pad may provide benefits of lowering reservoir pressure and reducing well control incidents.

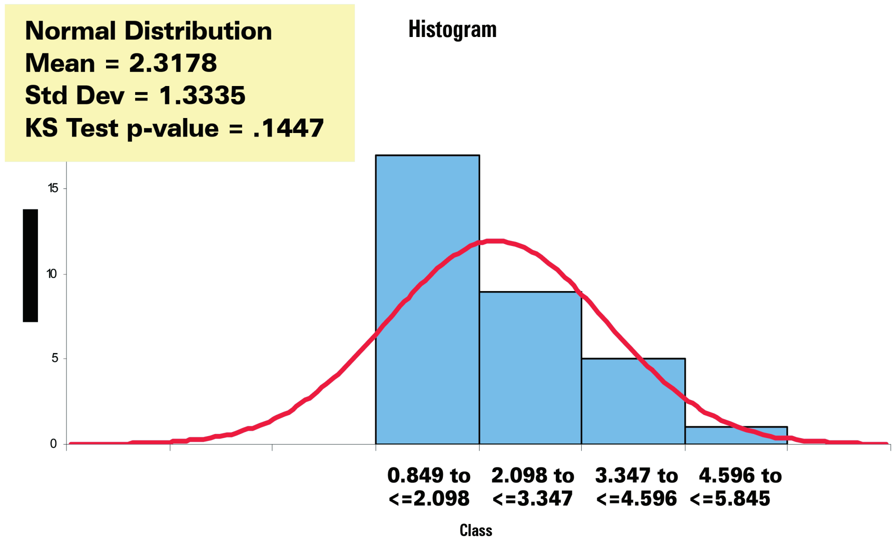
It is important to ensure a continuous water supply from surrounding kill lines, otherwise preparations must be made for water trucks to be on location at all times. A cooling water spray directed to the BOP stack is necessary to cool the equipment during well control.

The typical Class III BOP arrangement is annular, blind rams, pipe rams, drilling spool. Prolonged exposure to high temperature circulating fluids during the killing process may deteriorate pump parts and therefore an auxiliary pumping service is rigged up and tied in to the stand pipe manifold in case of rig mud pump failure.

The choke manifold is rigged up to divert well fluids as the initial response and return fluids to the mud pits as necessary.

Valves from the drilling spool through the diverter line are always open, except for the closed HCR valve next to the spool.

Finally, sufficient barite to build 15.0 ppg kill fluid is stored on location.



Annulus fluid density analysis using formation pressure data. The annulus fluid densities on adjacent wells were determined to range variously from 2.1 ppg, 3.3 ppg, 4.6 ppg, to 5.8 ppg.

CASE STUDY

Producer well #7028 was drilled in 2005 to replace a P&A'd well. Sub surface assessment revealed that the well is located in a structural high with an adjacent sealing fault. Seismic indicated a shallow temperature anomaly.

Contrary to other gathered information, surrounding producer wells were found to have relatively cool wellhead temperatures of less then 250°F.

There was limited offset drilling information with only one adjacent producer drilled since injection began in 1999. In this case, the Rindu was drilled with 10.5 ppg without incident.

The most recent history, a P&A on the same well pad, required a 14 ppg kill fluid to kill the well. Surrounding producer work-overs used at least a 10.5 ppg killing fluid.

Four nearby Rindu injector wells had shut-in pressure equivalents of 13.0 ppg to 11.3 ppg. On shut-in for 3 hours, the closest producer well stabilized at 5 psi, or 6.7 ppg equivalent. The well head temperature of 216°F converted to 15 psia from saturated steam tables.

On review of all information, it was decided to drill the Rindu with 11.0 ppg mud.

During drilling, the well kicked while penetrating the Rindu at 400' with 10 psi SICP (0.5 ppg). The flow line temperature remained at 90°F to 100°F so whereas the kick may have been steam driven, it was not a steam kick and conventional well control could be used.

The well was stabilized with 12.0 ppg kill weight fluid and drilling resumed to TD without further events.

CONCLUSION

Since implementation, a detailed risk and data assessment process has allowed successful steamed area drilling without a significant well control event.

This drilling program included areas that in the past recorded steam kicks, surface eruptions and blowouts

The assessment process has proven successful since it incorporates many different types of data that may be cross-referenced to derive the most likely subsurface risk scenario and resolution.

In addition, the multiple data tracks help prevent pertinent data from being overlooked.