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Is Your Mud a Fracturing Fluid or a Non-fracturing Fluid? – Preventing Induced Mud Losses by Controlling Spurt Losses

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Abstract

From a hydraulic fracturing point of view, conventional drilling mud is a perfect fracturing fluid. This fracturing tendency can substantially reduce the amount of pressure that a wellbore can contain and result in frequent mud losses if no changes are made to the mud.

Recent studies have found that adding particulates to drilling mud in a specific way can convert conventional fracturing mud to a non-fracturing fluid. This is achieved by quantitatively controlling a spurt loss for a particulate sealing fluid to be low enough that a seal for a crack can be securely formed. Without such control, the fluid invasion would inflate the crack beyond what the particulates can seal and enable fracturing to continue. A converting engineering process is realized by first characterizing spurt losses of an standardized particulate fracture sealing formulation at various concentrations against a slot disk; then, based on rock properties of a weak formation, calculate a critical invasion volume that can inflate the fracture to a critical sealing width equal to the slot width. A critical concentration of the sealing formulation with a spurt loss equal to the calculated critical invasion volume is then defined. When mud is treated with the particulate formulation at or above the critical concentration, the mud is converted into a non-fracturing fluid for the weak formation. When non-fracturing mud is used, induced mud losses can be prevented with a widened mud weight window.

In addition to its use in drilling fluid, this technology can also be used to convert completion fluid, cement slurry, or spacer fluid to prevent lost circulation during operations.

Introduction

Narrow mud weight windows are frequently encountered during offshore and in-field drilling. Because of a narrow mud weight window, wellbore pressure can often exceed the pressure that a wellbore can sustain, causing induced fractures and mud losses. Mud losses of more than 30,000 bbl are common during offshore drilling, which increases drilling costs. A much larger associated cost, however, is the cost of the downtime required to address the mud losses. The time for an offshore rig could cost as much as $1 million per day. In severe conditions, such as drilling a depleted deepwater formation, a natural mud weight window may be so narrow that drilling is considered to be impossible with conventional technologies.

Remedial technologies, such as the "one size fits many" foam wedge enhanced high fluid loss squeeze system[1], can cure lost circulation after it has been encountered. The industry, however, prefers preventative solutions that enable drilling to continue without stops. The technologies currently available in the marketplace for preventing induced mud losses can be dated back to the old days when particulate lost circulation materials (LCM) were arbitrarily added to mud in an attempt to prevent mud losses. DEA-13 studies[2,3] in the 1980s revealed the effects of sealing fractures for strengthening a wellbore, deriving a loss prevention material (LPM) method[4] of attempting to seal a fracture tip to strengthen a wellbore. GPRI studies[5] further verified that some particulate formulations are better than others when sealing fractures for higher wellbore pressure containment. In the LPM wellbore strengthening approach, drilling mud is added with an empirical particulate formulation. In this LPM method, rock properties are not specifically considered.

Rock properties have been part of an individual formulation design since the so called "stress cage" method came into the marketplace[6,7]. With the "stress cage" engineering, a design process considering rock properties is defined. In the design process, a fracture width is determined for adding particulates that match the fracture width in mud to prop the fractures for inducing additional stress to "stress-cage" the wellbore fluid. However, this length-dependent fracture width is determined by a fracture length arbitrarily chosen by the designer (often 6 in.). This gives an unwanted degree of freedom in the design process, resulting in an arbitrary fracture width from the arbitrarily chosen fracture length by a designer. Rock mechanics to support the selection of a 6-in. fracture length or other lengths are still not clear. With this arbitrary fracture width, assuming that the nominal particulate size distribution data are representative, the designer then attempts to determine the amount of the fracture width-matching propping particulates. However, these large particulates do not form the needed final formulation. It is then up to the designer to select the other small particulates that should be added to complete the formulation. Begun with an arbitrary fracture length and arbitrary small particulates, the designed final solution can hardly be unique. The solution can