CORROSION CONTROL IN DRILLING OPERATIONS

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INTRODUCTION

Corrosion of drill pipe and protective casing strings is now recognized as a serious problem. In the past, very little attention was given to corrosion, due to the lack of understanding that most drill-pipe failures were due to corrosion. In areas where serious embrittlement failures occurred, treatments were designed to treat only the zones where hydrogen sulfide entered the drilling fluid. Through time, various types of treatments showed that corrosion could be controlled. It became evident that treating the entire depth of hole provided the most benefits. The recent shortage of drill pipe has accelerated attention toward saving pipe with a proper drill-pipe corrosion program.

ECONOMICS

The economic value of combating corrosion in drilling fluids is evident, due to the high cost and difficulty in replacing drill pipe. Some contractors estimate their pipe costs from $0.03-$1.00 per foot per operating day. According to inspection, approximately 75-80% of drill pipe loss is due to corrosion. Corrosion also contributes to high costs in pump parts, bits, and casing in addition to lost time for fishing jobs and/or the loss of the well. The cost of corrosion control will vary from $50-$150 per rig per day for normal drilling operations. The chemical cost for corrosion control will vary due to the intensity of corrosion attack, which involves depths and conditions. No water-base drilling fluid is immune from becoming a corrosive fluid. It is clearly evident that corrosion can start at spud-in and continue to total depth. Continuous monitoring throughout the drilling operations can now be practiced. This information is used to determine when to treat and measure the effects of the treatment. Treatment can be adjusted to control the cause, form and rate of corrosion attack.

CAUSES OF DRILLING-FLUID CORROSION

The major causes of drilling-fluid corrosion are hydrogen sulfide, carbon dioxide and oxygen. More than one of these may be present at the same time while drilling. Corrosion contaminants in oxygen, hydrogen sulfide and carbon dioxide can be identified by the action of their corrosive gases which produce a dark brown or black corrosive by-product. The primary product of oxygen corrosion is magnetite, a black, acid-insoluble iron oxide, which can be detected by its adherence to a magnet. Iron sulfide is the main corrosion product of hydrogen sulfide. Iron sulfide will form a yellow precipitate when tested with an acid arsenic solution, thus showing sulfide was involved in causing corrosion. Iron carbonate results from carbon dioxide corrosion, and is detected by an acid solution which shows effervescence. Recognizing these different contaminants is necessary to determine a corrective treatment to remove or combat these cause of corrosion.

Hydrogen Sulfide

Hydrogen sulfide gas can cause two types of corrosion; pitting-type attack on metal surfaces or hydrogen embrittlement cracking. Even small amounts of H_2S, especially in the presence of oxygen or carbon dioxide can cause serious corrosion attack. Hydrogen sulfide is usually detected while drilling by measuring the loss of pH. Also, the use of a hydrogen sulfide test kit will indicate H_2S in the drilling fluids. Several methods are used in combating or removing H_2S. Establishing a basic pH (9.5-11) is highly recommended to help neutralize this acid-forming gas. Increasing the weight of the drilling fluid to seal off the hydrogen-sulfide-bearing zones is another remedy. Corrosion inhibitors such as filming amine or zinc chromate are used for filming the pipe. Iron sponge, zinc chromate and zinc oxide can be utilized to remove H_2S from the drilling fluids system. Oxygen scavengers are necessary to remove oxygen. Contractors consider H_2S a very serious threat to drill pipe and equipment when encountered in the drilling process.

Carbon Dioxide

Carbon dioxide contamination is quite common in drilling fluids and is often the major cause of corrosion. When CO_2 dissolves in drilling fluids, it forms carbonic acid which decreases the pH and increases the corrosivity. Conversely, as the pH rises, the water tends to become scale-forming and the corrosivity decreases. The presence of any oxygen or hydrogen sulfide increases the corrosivity of the carbon dioxide. The corrosion by-product iron carbonate is frequently detected in pits indicating the influence of acid-forming CO_2. Corrosive effects of carbon dioxide can be mitigated by controlling the alkalinity of the drilling fluids. For small amounts of CO_2, control is afforded by slight increase in the usual dosage of NaOH or KOH. A better approach, however, is to continue the usual NaOH or KOH treatments and then use lime as a supplementary treatment to control pH and Pf in the desired range. This method avoids buildup of CO_2 and must be used to avoid mud problems when combating large amounts of CO_2. Also, film-forming amines and oxygen scavengers are used in conjunction with the above methods.

Oxygen

Oxygen is considered one of the more serious corrosion accelerators in drilling fluids. Oxygen is always available and it characteristically results in a pitting form of corrosion attack. Oxygen enters the circulating system at the surface. Dissolved oxygen may be accelerated by water additions, solids-removal and gas separation equipment, and mud-mixing equipment. Pitting attacks from dissolved oxygen is the initial major factor in early equipment failure. The strong oxygen-pitting characteristics result from the formation of oxygen concentration cells which form below barriers or deposits on metal. The method used to control concentration cell corrosion is to keep the equipment clean, remove the oxygen, and coat the equipment with a filming-type inhibitor. The most effective method for combating oxygen corrosion is to keep the fluid in the pits as free of oxygen as possible and remove the remaining oxygen with an oxygen scavenger treatment. Drilling fluid usually cannot be kept completely free of oxygen as it circulates through the surface pits. However, with good corrosion control the oxygen concentration should be less than 1 mg/ l in the fluid being pumped down hole. Chemical removal of high continuous concentrations of oxygen from drilling fluids, expecially entrapped air, is difficult and expensive.

Treatments for dissolved oxygen include visual observation of surface equipment for aeration and the use of an oxygen scavenger such as sodium sulfide to reduce dissolved oxygen and in some cases additional catalyst such as nickel or cobalt to accelerate the reaction with dissolved oxygen. A film-forming amine is used as a supplemental treatment when using oxygen scavengers. Another type of filming treatment is zinc chromate used primarily to prevent oxygen-type corrosion.

SCALE

Scale is a problem often encountered during the drilling process. Scale forms deposits on pipe which allows corrosion concentration cells to develop. Scale is noticeable in the deeper holes being drilled. Also, dissimilar waters are a major cause of scale. Caution should be taken when using lime for pH when drilling below certain depths. Scale can be treated by using a scale inhibitor such as an organic phosphonate.

MONITORING CORROSION

Drilling fluids are continually undergoing changes as new formations are penetrated. Various methods are available to check the corrosion rate of drilling fluid. The corrosion rate can be monitored in the drilling system with the use of: (1) a Corrator*, (2) a Parameter**, (3) a galvanic probe or (4) drill string coupons. Due to the changing nature of drilling fluid environment, a quick and accurate instrument is needed to monitor corrosion. The Parameter and Corrator utilize the polorization resistance method. These are often portable with a stationary probe in the drilling system. The galvanic probe works on the electrochemical circuit formed in the galvanic cell. This is widely used by drilling contractors due to the simplicity of a quick readout microamp measurement which can be made at the rig. Drill pipe coupons are widely used to study the effect of corrosion on drilling fluid; rate, form, and cause of corrosion can be evaluated with this method. An advantage of drill string coupons is that they can be exposed down hole to actual drilling conditions. A good criterion for drill string coupon corrosion rate is two pounds per square foot per year or less, without isolated pitting. Oxygen meters are used to detect the amount of dissolved oxygen in the system. An oxygen meter should be used at the suction pit and flowline to judge the effect of an oxygen scavenger in the drilling fluids. A sulfite residual kit is necessary to gauge the effect of the oxygen scavenger in the system. The sulfite residual reading is an indication of the amount to be used to control dissolved oxygen in the system. The above indications are helpful in determining the rate of corrosion and the chemical treatment to be used in the drilling fluids. Recognizing, measuring, and elimination of drill pipe corrosion is an asset to the drilling contractor and producing companies.

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* Corrater is a registered trademark of Magna Corp, Santa Fe Spring, California

** Parameter is a registered trademark of Petrolite Corp., Petreco Division, Houston, Texas