Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries

Downstream Segment

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Introduction

Sulfidation corrosion, also often referred to as sulfidic corrosion, of piping and equipment within the refining industry continues to be a significant cause of leaks leading to equipment replacements, unplanned outages, and incidents associated with large property losses and injuries. The objective of this recommended practice (RP) is to provide practical guidance to inspectors, maintenance, reliability, project, operations and corrosion personnel on how to address sulfidation corrosion in petroleum refining operations.

This document is intended to provide a better understanding of sulfidation corrosion characteristics. Examples of failures are discussed to highlight the common causes. An overview of the two mechanisms of sulfidation corrosion (with and without H_2 present) and the methods used to control and inspect for sulfidation corrosion are summarized. The data herein is a compilation of information extracted from published technical papers, industry information exchanges (NACE and API) and contributions from several owner/operators. Some refining companies have developed proprietary methods to predict sulfidation corrosion and these were not made available as part of this effort.

Common refinery units in which essentially H_2-free sulfidation corrosion occurs are the crude/vacuum, fluid catalytic cracker, coker, and visbreaker units. Hydroprocessing and hydrocracking units experience H_2-free sulfidation corrosion in their feed and distillation sections. They experience sulfidation in the presence of hydrogen in their reaction sections. This sulfidation in the presence of H_2 is typically referred to as H_2/H_2S corrosion.

Included in this RP are:

— background to the degradation mechanism,

— the most common types of incidents and damage observed,

— root causes of sulfidation corrosion,

— methods to predict and monitor the corrosivity of systems,

— materials selection for new and revamped processes,

— inspection and nondestructive examination (NDE) methods used for detecting sulfidation corrosion.

Materials and corrosion specialists should be consulted for additional unit-specific interpretation and application of this RP.

Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries

1 Scope

This recommended practice (RP) is applicable to hydrocarbon process streams containing sulfur compounds, with and without the presence of hydrogen, which operate at temperatures above approximately 450 °F (230 °C) up to about 1000 °F (540 °C). A threshold limit for sulfur content is not provided because within the past decade significant corrosion has occurred in the reboiler/fractionator sections of some hydroprocessing units at sulfur or H_2S levels as low as 1 ppm. Nickel base alloy corrosion is excluded from the scope of this document.

While sulfidation can be a problem in some sulfur recovery units, sulfur plant combustion sections and external corrosion of heater tubes due to firing sulfur containing fuels in heaters are specifically excluded from the scope of this document.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced doucment (inlcuding any amendments) applies.

API 510, *Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*

API 570, *Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-service Piping Systems*

API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

API Recommended Practice 578, *Material Verification Program for New and Existing Alloy Piping Systems*

API Recommended Practice 580, *Risk-Based Inspection*

API Recommended Practice 581, *Risk-Based Inspection Technology*

API Standard 579-1/ASME [1] FFS-1-2007, *Fitness-For-Service*

3 Definitions and Acronyms

For the purpose of this document, the following definitions apply.

3.1 Definitions

3.1.1
low-alloy steels
Steels that contain 1 to 9 % Cr and 0.5 to 1 % Mo.

3.1.2
low-silicon-containing carbon steels
Steels that contain less than 0.10 wt % Si, the minimum limit for ASTM A106 piping.

[1] ASME International, 3 Park Avenue, New York, New York, 10016, www.asme.org.