Accelerated FGD Corrosion

Understanding the Cause, Finding a Solution

State-of-the-art flue gas desulfurization (FGD) systems have been and are being installed in most coal-fired electric generating units in the United States to meet regulatory emission requirements for control of sulfur dioxide (SO_2). These systems are capable of removing 95% or more of the SO_2 in the flue gases. However, in the past year, utilities have been confronted with a troubling trend. Some of the newer wet FGD units have experienced severe corrosion in just three years, and in extreme cases, in as little as three months.

THE STORY IN BRIEF

An aggressive form of corrosion has been found in relatively new flue gas desulfurization systems installed in U.S. coal-fired plants. In response, EPRI has launched a rapid-response project to investigate the root cause of the corrosion and to develop inspection and mitigation methods.

The corrosion most commonly is found below the liquid level in the FGD absorber vessels and piping. It first appears as pitting in weld heat-affected zones, weld metal, and base metal and most often is associated with areas under heavy deposits of gypsum, an FGD byproduct. Corrosion has been serious in some plants and in extreme cases has penetrated vessel walls. The corrosion has been found in many designs produced by several manufacturers.

To date, the cause is unknown, but in preliminary investigations, the common factor appears to be absorber vessels and installations constructed since about 2004 using duplex stainless steel alloy 2205 and possibly other duplex stainless steels. Initial EPRI surveys show that at least 20% of the approximately 360–370 FGD systems in the United States have this material in major components.

"A structural compromise in significant systems such as FGD units is a serious concern for plant operators," said Chuck Dene, EPRI project manager. "FGD units are costly, with total capital costs on the order of $400 per kilowatt. FGD vessels can hold 1–2 million gallons of slurry, which is typically 20% solids. Corrosion that violates minimum wall thickness can jeopardize the structural integrity of a tank. If a tank were to rupture, it could have catastrophic effects on surrounding equipment and shut down a plant. In addition, emission regulations require that a unit not run without the FGD system in service."

Maintenance and outage costs to address corrosion can be significant. Mitigation measures—even temporary stopgap measures—have been reported to cost as much as $8 million. Outages to address the issue typically are unplanned, and it can take weeks to clean, inspect, and repair vessels.

Surveying Systems

The issue was first brought to EPRI's attention before its October 2010 Generation Sector advisory meeting. In early November, EPRI convened a meeting of key stakeholders. In less than two months, EPRI programs 87 (Fossil Materials and Repair) and 75 (Integrated Environmental Control) jointly launched a supplemental project to address the issue.

"Once we saw the seriousness of the attacks and their prevalence throughout the industry, we knew we had to act quickly," said John Shingledecker, EPRI senior project manager. The project aims to identify the root cause, compile guidelines for inspection and fabrication, and develop repair and other mitigation strategies.

First, the project team is surveying U.S. utility FGD systems experiencing corrosion. The survey is collecting information on corrosion in FGD absorber vessels, piping, and spray headers/nozzles, along with detailed data on materials, fabrication techniques, construction quality assurance/quality control, operating environments (basic water chemistry, scaling, etc.), and corrosion levels and locations.

With the survey results, the EPRI team will document all FGD system designs, chemistries, and materials susceptible to accelerated corrosion. Generally, FGD systems include wet scrubbers, spray dryers, and dry sorbent injection systems. The corrosion in question has been found only in wet scrubbers, which typically remove SO_2 from the flue gas with a limestone or lime slurry spray. The industry relies on wet FGD absorber vessels of two main designs: spray towers/tray towers, which spray slurry into the bulk gas flow, and jet bubble reactors, which introduce the flue gas into the bulk slurry.

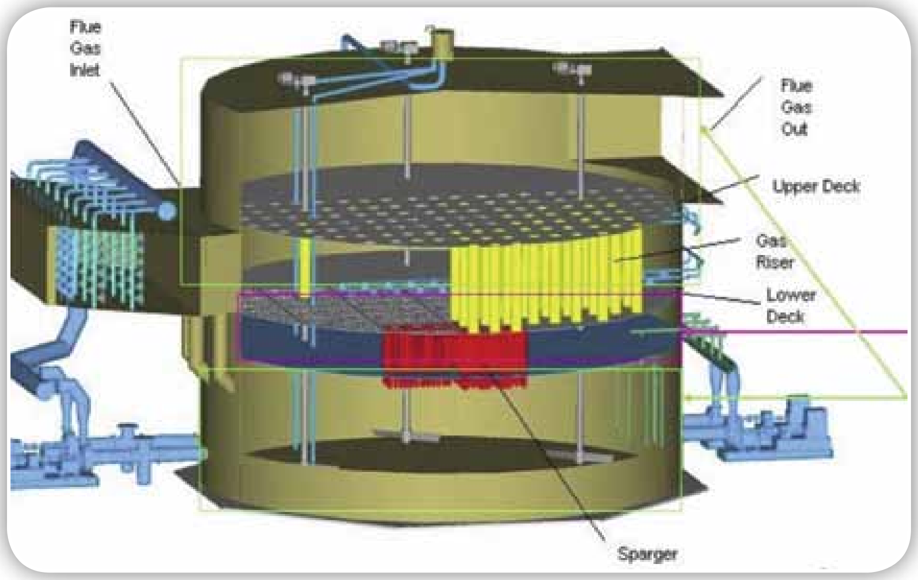
Metal and Chemistry Issues

Early indications point to chemistry issues—evidenced by the presence of hard, tenacious scales and deposits on walls and floors—and/or a factor associated with the fabrication of the metallic vessels.

Prior to the early 2000s, FGD absorbers were designed using Type 317L stainless steel or a variation, such as Type 317 LMN. The LMN grade is fully austenitic and has controlled increased additions of nitrogen and molybdenum. The combination of molybdenum and nitrogen enhances resistance to pitting and crevice corrosion, especially in process streams containing acids, chlorides, and sulfur compounds at elevated temperatures.

Nearly a decade ago, in seeking higher SO_2 removal and different chloride concentrations during operations, a fundamental shift occurred in the way FGD systems were designed and operated. The price of nickel-based alloys spiked, rising by four to seven times. Manufacturers sought other metals, such as duplex stainless steels.

Representative cross-sections, showing corrosion on Alloy 2205 in a weld and in base metal. Left: through-wall leak in 11/16-inch base metal after 11 months in service. Right: surface and subsurface pitting structure after 11 months in service.



Jet bubble reactor. For this schematic, the purple box indicates Alloy 255 duplex stainless steel in the froth zone (wet/dry zone) of the shell, and the green boxes are Alloy 2205 duplex stainless steels above and below. Illustration courtesy of M. J. Crichton.

Duplex stainless steels have a two-phase microstructure consisting of roughly 50% austenitic stainless steel and 50% ferritic stainless steel, making them about twice as strong as regular austenitic or ferritic stainless steels. Depending on their content, duplex alloys have a range of corrosion resistance. With less nickel and molybdenum, these alloys can cost significantly less than austenitic stainless steels, and because of their increased strength, they can be manufactured with reduced section thickness.

Initial evidence indicates many affected FGD systems are fabricated with one of the most common duplex stainless steels, Alloy 2205, a 22% chromium, 3% molybdenum, 5%–6% nickel, nitrogen-alloyed stainless steel. Some affected systems are made of a similar duplex alloy, 255, with a slightly different composition. Concern is mounting that earlier-generation absorber vessels fabricated with austenitic stainless steels may be subject to corrosion as well, but that the attack has gone undetected. As a result, the EPRI study will investigate duplex stainless steels, stainless steels, and alloys prevalent in today's FGD fleet.

Absorber vessel environments are very corrosive and may vary significantly in different plants. Materials selection for each plant must be based on corrosive media, coal quality, available space, operating conditions, plant design, and economics. Slurry chemistry in each plant may be a key factor in driving the corrosion attack.

Flue gas is introduced into an absorber through the inlet duct. Temperatures from 250°F–400°F (121°C–204°C) are usually high enough to preclude corrosion in much of the duct. However, in the portion of the duct immediately ahead of the absorber, the hot gas and moisture mix to create a very corrosive "wet/dry" area, either through the intentional pre-quenching of the gas or through the unintentional recirculation of the saturated gas from the absorber.

Corrosion can be severe in the outlet duct, which carries the scrubbed gas to the stack for discharge. Temperatures range from 109°F–176°F (43°C–80°C), and the gas is saturated with moisture and may contain sulfuric, hydrochloric, or hydrofluoric acid, depending on coal quality, firing, and absorber operation.

Inspection Guidelines

Relatively early in the project, in 2011, EPRI is slated to deliver inspection guidelines. These will provide guidance on pre-inspection planning and cleaning of metal surfaces, inspection procedures for spray tower and jet bubble reactors, and documentation of inspection results. Based on successful utility inspections conducted to date, the guidelines will include detailed photographs of corrosion types and locations to help ensure that all utilities are discovering and correctly identifying corrosion in its initial stages, when signs often are not visible without surface preparation and cleaning.

"The corrosion involves very small pinpoint holes that you cannot see in a typical walk-by," said Tom Hart, manager, Flue Gas Desulfurization and Chemical Engineering, American Electric Power. "You have to use much higher pressure water blasts or a grit abrasion blast to clean the surface of the absorber vessel, so that very small pits are exposed in the base metal or the heat-affected zones of the weld. And then you need to look very closely and use light shining across the surface to cast shadows. You may also need to probe the pits with probing wires or excavate them with dental picks and clean out the residue and actually even sandblast away the covering metal. It's a very time-consuming and meticulous process."

Standardizing inspection procedures will help to ensure that utilities can compare data among many units. Once the

Corrosion damage at a wall and floor joint

inspection guidelines have been published, the project team may return to units where there were questions to ensure that the team is getting all possible data.

Root Cause Analysis

Combining survey findings with a review of past EPRI studies may make it possible to complete a root cause analysis as early as mid-2011. The analysis will include information on materials selection, handling practices, erection processes, weld procedures, corrosion and failure mechanisms, and operation variables and will identify areas requiring more data.

"We expect the root cause analysis will not necessarily give us one smoking gun answer, such as a slight change in pH level," said Shingledecker. "Instead, I think it will define the critical areas where we don't have the proper information and need to do more research in order to make materials decisions or life-type assessments or performance assessments."

The project will identify the most effective mitigation and repair methods to address the cause, including welding, linings, and coatings. It will also review utility field experience with mitigation measures used to date, including welding lap plates over corroded areas on vessel floors and walls, applying coatings, and installing cathodic protection.

To understand the feasibility and effectiveness of recommended mitigation measures, the project team will test current materials and fabrication practices (welding, surface preparations, finishes) in laboratory and field environments and compare them with recommended mitigations (coatings, alternative vessel materials, and alternative cladding materials). Researchers then will formulate standard repair procedures and develop fabrication guidelines, addressing proper construction practices, contamination and surface acceptance, and welding procedures.

Throughout the project, participants will meet at least twice a year as the new Corrosion in FGD Materials Interest Group to review the project status, identify future project research, identify longer-term R&D, and exchange information on FGD materials issues.

"This is the kind of project where the industry needs EPRI's leadership," said Hart. "The project is collecting a lot of data on who did what: what types of materials were used, what weldments were made, what weld rods were used, how the vessel was brought into service, what coal is burned, and what chemistries have been in place. We need EPRI to assemble all the data and then bring their knowledge to bear in analyzing the data across the industry to find the root cause. Until we know the cause and find a reliable, long-term fix, utilities are not going to have the level of confidence they need to use these materials and install new systems."

This article was written by Jonas Weisel. Background information was provided by EPRI's John Shingledecker, jshingledecker@epri.com, 704.595.2619, and Chuck Dene, cdene@epri.com, 650.855.2425. Tom Hart of American Electric Power also contributed to the article.

Chuck Dene is a senior project manager in EPRI's Integrated Environmental Controls program. His project responsibilities include improvements in FGD chemistry for removal of SO_2, acid gases, mercury, selenium, and other toxic metals; evaluation of integrated emission control technologies; and continuous emission monitoring technologies for process control and compliance reporting. He received his B.S. degree in chemical engineering from Wayne State University.

John Shingledecker is a senior project manager in EPRI's Major Component Reliability research area. He leads the Fossil Materials and Repair program, which provides the power industry with materials use and selection guidelines, welding and repair solutions, corrosion mitigation methodology, and remaining-life tools to increase plant availability, reduce failures, and improve efficiency. Before joining EPRI in 2008, he worked at Oak Ridge National Laboratory, where he was a principal investigator for projects supported by the U.S. DOE Office of Fossil Energy's Advanced Research Materials Program. Shingledecker holds B.S. and M.S. degrees in materials science and engineering from Michigan Technological University.

Tom Hart is Manager of Flue Gas Desulfurization and Chemical Engineering for American Electric Power. He has worked closely with EPRI on a number of projects, sits on the Generation Sector's Integrated Environmental Controls (P75), and chairs the Particulate and SO_3 Controls (P76). He also chairs the newly formed Corrosion in FGD Materials Interest Group.