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Case studies into the Performance and Benefits of Advanced Ceramic Coating Technologies for Corrosion, Erosion and Slagging Mitigation in Fossil Fuel Fired Power Generation Units.

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ABSTRACT

Tube material loss, leading to tube failure, due to corrosion and/or erosion is one of the leading causes of forced maintenance outages in the coal and biomass fueled power generation industry. In addition to increasing the required funds for operations and maintenance of the facilities, modifications made to the equipment for emissions reduction compliance have, in many cases, increased the rate of tube material loss. Accordingly, there has been demand for advancements in innovative and cost effective materials technology to mitigate the loss of tube material and thus reduce the frequency of unscheduled and non-routine maintenance events. The employment of High Temperature Ceramic Coating Technology in the power generation industry has proven to be an effective means of protecting the underlying boiler tube material from erosive and corrosive material losses and has afforded additional benefits related to increased heat transfer, increased efficiency, reduced air and flue flow energy consumption and reduced fuel consumption through the reduction of slag and deposits adhering to the coated heat transfer surfaces.

Key words: Ceramic coating, power generation, boiler tube, tube failure, ash slag, sulfidation corrosion, material loss, corrosion, erosion, slagging, efficiency, heat transfer, maintenance, outage.

INTRODUCTION

Boiler tube failures remain one of the leading causes for forced maintenance outages in the coal and biomass fueled power generation industries. Forced outages related to boiler tube failures cost the power generation industry billions of dollars annually.

These costs are attributed to both the maintenance activity associated with the restoration of power generation equipment to a safe operating condition as well as the loss of production. The cost involved in restoration of the equipment depends largely on the severity and location of the damage that led to the forced outage event and the costs can be measured in the hundreds of thousands of dollars. The cost implications for the loss of energy sales for the period of time that the unit is offline for maintenance can be measured in millions of dollars. These costs are dependent on the size of the boiler unit and the sales price per kWh.

Traditionally, fireside corrosion (also referred to as high temperature corrosion), fly ash and soot blower erosion have been some of the most common causes of boiler tube failure resulting in forced outages.

Legislation pertaining to emissions reduction has led to significant changes in the industry, particularly as it pertains to coal fired generation. The introduction of low NOx burners and increased staging of the combustion process through the use of separated over fire air for the purposes of reducing NOx formation has in some cases resulted in a drastic increase in corrosion in certain areas of the boiler.
The addition of tail end flue gas treatment equipment for emissions control allows for, and has prompted some facilities to use less expensive and a lower calorific grade of coal in an effort to offset the increased operations and maintenance costs associated with the equipment. These lower grade fuels often contain high levels of sulfur and ash.

Fireside corrosion of carbon or low alloy steel materials, generally used for the manufacture of boiler tube components, is a well understood and documented subject, and is typically attributed to the formation of acids during combustion process reactions involving impurities such as sulfur, sodium and potassium present in the fuel. Prior to the introduction of low NOx combustion equipment and processes, an approach to mitigate the effects of fireside corrosion was to ensure the presence of an oxidizing environment in order to facilitate the formation of iron oxide scale on the boiler tube surface.[1]

$$3Fe + 2O_2 \rightarrow Fe_3O_4 \quad (1)$$

The iron oxide scale constituted a dense and well bonded protective barrier between the acidic combustion products and the underlying boiler tube material.

The creation of an oxygen starved reducing environment, created by sub stoichiometric combustion, through the installation of low NOx combustion equipment and over fired air systems inhibits the formation of harmful emissions, yet has, in many cases, resulted in a drastic increase in corrosion rates of boiler tubes in the reducing zone. Corrosion rates of up to 3 mm (120 mils) loss in tube wall thickness per year have been reported.[1]

This reducing atmosphere prevents the formation of the protective iron oxide layer on the boiler tube surface.

The root cause of the high corrosion rates is deposition of FeS rich slags to the tube surface. These deposits decompose to create corrosive sulfur species leading to severe sulfidation corrosion of the waterwall tubes. The FeS is created through the partial combustion of pyrite (FeS_2) commonly found in coal.[2]

The combustion conditions promote the formation of the more corrosive H_2S over SO_2 and SO_3.[3, 4]

$$FeS_2 + CO + H_2O \rightarrow FeS + H_2S + CO_2 \quad (2)$$

$$S_{(org)} + H_2 \rightarrow H_2S \quad (3)$$

$$Fe + H_2S \rightarrow FeS + H_2 \quad (4)$$

Where an oxide scale (Fe_3O_4) may have already formed on the tube surface, this may also be transformed into FeS.

$$Fe_3O_4 + 3H_2S + CO \rightarrow 3FeS + 3H_2O + CO_2 \quad (5)$$

Erosion, the abrasive wear of ash/particulate entrained flue gas, plays a significant role in the loss of boiler tube material resulting in boiler tube failure related forced maintenance events. Though a number of factors including particulate loading, impact angle amongst others play a role in the rate of material loss due to erosion, particle velocity is the most important parameter.

$$E \propto V^n \quad (6)$$

Where:
E is erosion rate.
V is particle velocity.
n is velocity exponent.
The exponent n has been found to vary roughly between 2 and 4.26.[5]

Particle velocity is a function of flow conditions in a certain area of a boiler and erosion rates are likely to be uniform throughout that area, however accelerated localized flow conditions caused by flow impedance or other means can result in highly increased rates of erosive material loss.

The most common means of removing slag deposits in boiler equipment is through soot blowing, whereby a jet of compressed air or steam is directed at the accumulated slag.
The use of soot blowers introduces accelerated localized flow conditions as previously discussed, and can lead to rapid tube material wastage in instances where they are used more frequently than necessary, or where misaligned soot blower operation impinges on areas outside of the intended area.

The agglomeration of ash or slag deposits on boiler tube components is commonly referred to as slagging. Slagging can have serious detrimental effects on the efficient operation and reliability of power generation equipment. The primary purpose of boiler tube is to facilitate the transfer of heat. The presence of slag on a boiler tube restricts the heat transfer and results in sub optimal operation. The inefficiency in operation will cause the unit to operate at less than capacity, or consume additional fuel in order to maintain load. In some cases where online cleaning methods are unsuccessful in the removal of slag from heat transfer surfaces, the unit will be cycled. This causes temperature fluctuations leading to contraction and expansion of components. There is significant difference in the coefficient of thermal expansion between metallic boiler components and slag, and cycling the unit is often successful in forcing the shedding of the slag deposits. Cycling does not result in the complete loss of power production, yet the unit will operate at a reduced average load.

Where cycling the unit unsuccessful, the unit may have to be brought offline for manual cleaning operations.

ADVANCED CERAMIC COATING TECHNOLGY

Overview

Furnace Mineral Products is the recognized global leader in the manufacture and application of proprietary high temperature ceramic coatings for the protection of boiler fireside components, and has manufactured and applied the GreenShield[(1)] range of advanced ceramic coatings since 1985. These ceramic coatings are comprised of a proprietary combination of silicon dioxide (SiO_2) based ceramic particles and chemical compounds in a water based binder. The coatings are spray applied onto specially prepared substrate surfaces in thin multiple layers to a specified coating thickness, typically 150-300µm (6-12 mils), to suit the operating conditions and service environment. The coating will dry to the touch under ambient conditions in the boiler unit. When the boiler is started and brought up to operating temperature, the coating cures and chemically bonds to the substrate material, maintaining its green color and glass like surface. A cross section of cured ceramic coating can be seen in Figure 1 below. The cross section shows the sharp angular ceramic particles in a dense, tightly packed matrix.

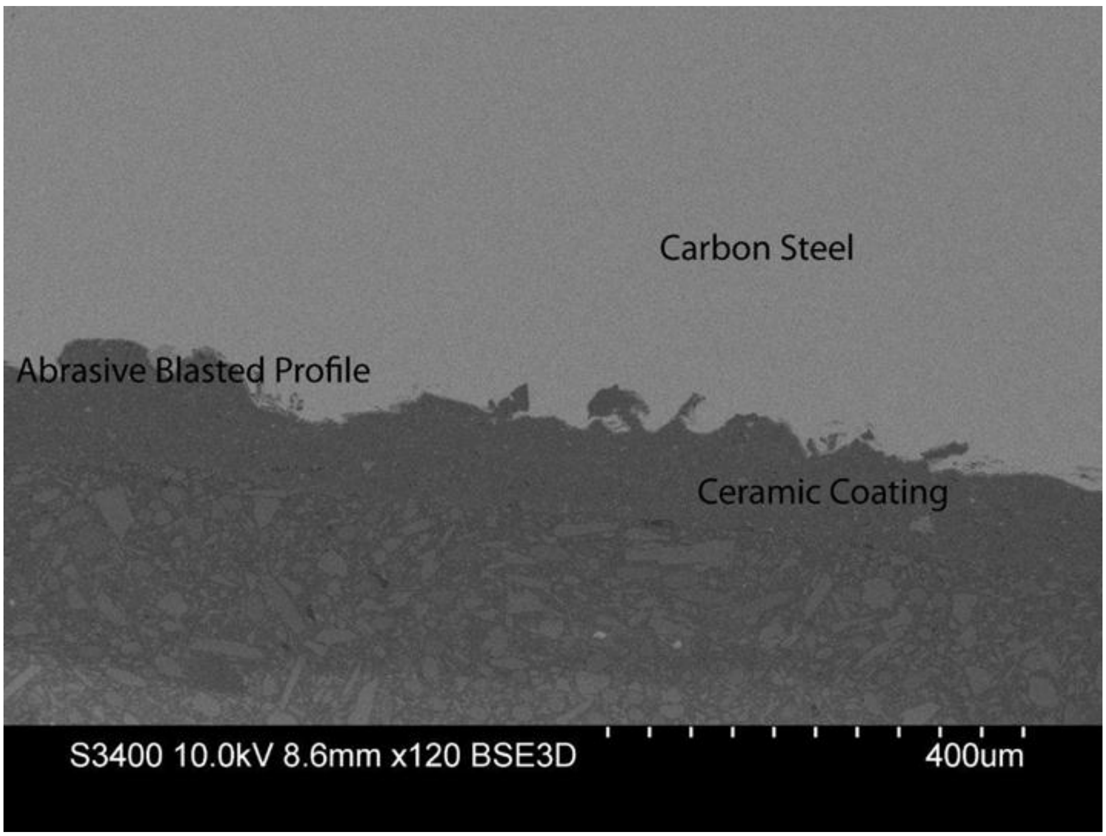

Figure 1: Ceramic Coating Cross Section

(1) Trade name.

CASE STUDIES

Case Study #1

Overview

Power Generation facility owns and operates two coal fired power generating units in Southeast USA. The units are opposed wall-fired and the net output per unit is approximately 650 megawatts.

The units were first commissioned in 1983 and 1984.

The plant's primary fuel is eastern bituminous coal from mines in western Kentucky and southern Illinois but it is also capable of firing a combination of coal and petroleum coke (pet coke). Fuel sulfur content ranges between 2.8% and 3.6% depending on the blend ratio.

Emissions control retrofits including the replacement of existing burners with new low NOx burners, and upgrades to the Over Fire Air system were completed on each unit. Units 1 and 2 modifications were completed in the fall of 2006 and spring of 2007 respectively.

The boiler water wall tubes and superheat pendants were subject to corrosive attack and heavy slag deposition.

A program was launched in the fall of 2007 to address the corrosion and slagging issues in both of the units. The most aggressive areas were addressed first, and the less aggressive areas received attention during subsequent maintenance outages. To date, a total of 90,000 square feet of waterwall and superheater tube area have been protected by the use of ceramic coating technology.

Field inspection observations

During regular scheduled maintenance outages, an assessment of the existing coating is performed in order to verify the performance and to determine anticipated coating life expectancy. The assessment of the existing coating involves both qualitative visual inspection and quantitative coating thickness measurements.

General observation of the surface condition protected by ceramic coating on furnace waterwalls exhibited slight uniform film deposition with no sintering to the tube surface or heavy agglomeration.
Slag deposition on the ceramic coating surface exhibited varying degrees of tightness and bond strength. In most areas, the deposit was easily removed from the coating by wiping the surface with a rag. In other areas tapping the slag with a hammer removed the deposit film and revealed the underlying ceramic coating. (Figure 2)

Figure 2: Thin slag deposit removed revealing intact ceramic coating in lower furnace

Slag agglomeration on ceramic coated superheater tubes was generally patchy and very loosely adhered. (Figure 3)

Areas in the superheat section unprotected by ceramic coating revealed a thick slag agglomeration with complete slag agglomeration between the tubes in some areas. (Figure 4)

Figure 3: Patches of loosely adhered slag on coated superheater element is as found condition

Figure 4: Heavy, well adhered slag on uncoated superheater element

Results

The ceramic coating has eliminated the corrosive tube material losses on a large scale in severe and moderate corrosive conditions. Areas subjected to the most severe corrosive conditions were easily identifiable by the heavy slag agglomeration and the absence of the green ceramic coating. This allowed inspectors to perform in depth nondestructive examination in isolated areas to identify those areas that may require additional attention.

A significant reduction in the slag agglomeration on the waterwall and superheater tubes was realized through the use of ceramic coatings. During operation the units were able to maintain near optimum heat transfer resulting in major cost savings realized through increased overall efficiency.

There have been significant cost and time savings in routine scheduled maintenance outages since the commencement of the ceramic coating program. These savings can be summarized as follows:

- The performance of the ceramic coating for the protection against corrosive material losses has greatly reduced the scale of maintenance required to replace or restore components to serviceable condition.
- The rate of application of ceramic coatings over alternate methods of protection realize much shorter turnaround in the protection of components against further damage anticipated in future production runs ahead of the following scheduled maintenance event.
- The slag shedding properties of the ceramic, coupled with its high visibility, reduce the time and effort associated with cleaning the unit ahead of inspection, as well as the time and effort associated with the inspection.

Case Study #2

Overview

The basic principles of circulating fluidized bed (CFB) boiler operation involve the combustion of fuel in a fluidized bed of inert material in the lower half of the furnace. The bed material is typically comprised of sand and ash. The primary means of heat transfer in the furnace of a CFB boiler is conduction between the heated bed material and the furnace waterwall tubes. The furnace waterwalls are subject to significant erosion and abrasion through the constant circulation of particulate.

Erosion and abrasion in a CFB furnace create significant chronic problems for the operators of the furnace. Boiler tube material loss through erosion is the single biggest cause for tube failure leading to forced outages in the CFB industry. Due to the severity of the condition CFB plants invest significant time and funds into erosion monitoring programs in order to identify and address areas of concern on the boiler waterwalls.

The membranes between adjacent boiler tubes are also subject to abrasion and erosion in CFB units. Whilst the loss of material leading to holes in the membrane material does not necessarily result in forced outage activity, membrane holes lead to ash leaks. Hot ash leaking from the boiler creates a significant health and safety concern to personnel, general housekeeping concerns, as well as general equipment concerns as the airborne ash can lead to damage of external boiler equipment such as pumps and motors.

The membranes are often narrow and difficult to access with ultrasonic thickness measurement equipment, precluding the membrane from erosion monitoring programs.

Ceramic coatings have been applied to several thousand square feet of CFB furnace waterwall tubes in several facilities in North America. The dense matrix of ceramic components constituting the ceramic coating are inherently hard resulting in a coating that is of high hardness and thus intrinsically resistant to erosion and abrasion. The obvious green color of the ceramic coating makes it easily identifiable, and the presence of the green color in the unit is indicative of the fact that the coating is in place and that there has been no loss of boiler waterwall material in that area.

Results

Ceramic coating performance in the protection of CFB boiler waterwalls is best described by excerpts of testimonials from users of the ceramic coating technology:

The ceramic coating protects the waterwall tubes and membranes from erosion in all but the most severe erosion areas of the furnace. Throughout a year of continuous operation there no external ash leaks form eroded membranes. Upon inspection after 12 months operation all of the ceramic coating installed was in place. The need to map the tube thickness in the lower furnace was eliminated. Locating and addressing eroded sections was a matter of identifying areas of drastic color changes.

Case Study #3

Overview

A power generation facility in the Rocky Mountain region of the USA operates a circulating fluidized bed boiler (CFB) with a gross generating capacity of 41MW. The unit began commercial operation in 1990. The facility burns waste coal from a nearby mine, and makes use of limestone injections systems for the removal and capture of sulfur as a means of reducing the amounts of SOx emissions to the environment.

The superheat sections of each boiler become plugged with sulfated limestone agglomeration up to the point that the units had to be brought off line.

Under normal operating conditions with clean superheater sections, the pressure differential (dP) would average 1.75” H_2O (inches of water column). As the superheater sections became plugged, average dP across the sections would approach 8” H_2O, at which point the unit would be shut down in order to remove the agglomeration. Forced outages related to plugging were occurring 1 to 2 times per year.

A forced outage was a very costly event often costing the company in excess of $250,000 in lost revenue, contractor fees and employee overtime.

Contractors and employees would spend a minimum of ten days in the units with hammers, rods and air lances cleaning the areas between the superheat tubes.

The plant was eager to find methods to reduce the frequency of forced outages. Ceramic coatings were applied to the tubes in the superheater sections to inhibit the initial sintering that leads to agglomeration.

Prior to the initial application of the ceramic coating, the heavily plugged sections of superheaters (Figure 5) were cleaned and the bare tube surface prepared for the application. Figure 6 depicts a cleaned section of superheater. Ceramic coating was applied to 100% of the tubes in both superheaters. (Figure 7)

Figure 5: Plugged section of superheater prior to cleaning and ceramic coating application

Figure 6: Section of superheater at the completion of cleaning

Figure 7: Superheater section at the completion of ceramic coating application

Results

The unit was returned to service and operated for one year without any agglomeration issues at all.

The dP across both boiler superheat sections never exceeded 2” H_2O during the first uninterrupted year of operation and has continued to do so for 7 years with regular maintenance of the ceramic coating. Other gains were a reduction in plant parasitic load due to the ID fans operating at less amperage due to the clean superheat sections. The clean superheat sections also have increased the unit’s ability to classify ash, which has resulted in lower limestone use and increased sulfur capture. The fuel feed is also down due to the added heat transfer abilities with the clean tubes versus the tubes coated with thick agglomeration.
Another realized savings was the reduced amount of plant and contract labor needed to remove agglomeration during the annual outages. The agglomeration found on the superheat tubes during the first outage after the cleaning and coating was very soft and came off very easy with dead blow hammers.

The amount of debris that was removed from the boilers the following year after the first application of the ceramic coating was approximately 80% less than any of the previous years.

The plant owners have estimated the return on investment in the initial coating application was 6 months.

Case Study #4

Overview

A power generation facility in the Northeastern region of the USA operates a circulating fluidized bed boiler (CFB) with a gross generating capacity of 36MW. The unit began commercial operation in 1992.

The facility burns waste coal and injects limestone for the removal and capture of sulfur from the flue gas.

Waste coal ash and limestone are extremely abrasive. The velocities and intense sweeping action in this CFB unit are the causes behind the erosive material loss of 380-635 µm (15-25 mils) per year that had led to the replacement of the finned tube economizer.

The configuration of this economizer section as well as the presence of fins makes does not facilitate effective non-destructive tube evaluations for the purposes of predicting remaining life expectancy of the economizer components.

Ceramic coating was applied to the economizer bundle in order to protect the finned tubes form erosion and extend the life expectancy of the assembly.

A prototype of the economizer was constructed in order to assist in the development of surface preparation and coating application techniques for the components and configuration specific to this economizer. Figure 9 illustrates the economizer prototype, economizer tube configuration and restricted access to surfaces of components.

Figure 9: Economizer prototype

Ceramic Coating was successfully applied to the economizer bundle to a nominal thickness of 200 µm (8 mils) during the fall of 2008. Figure 10 below shows a section of the coated economizer.

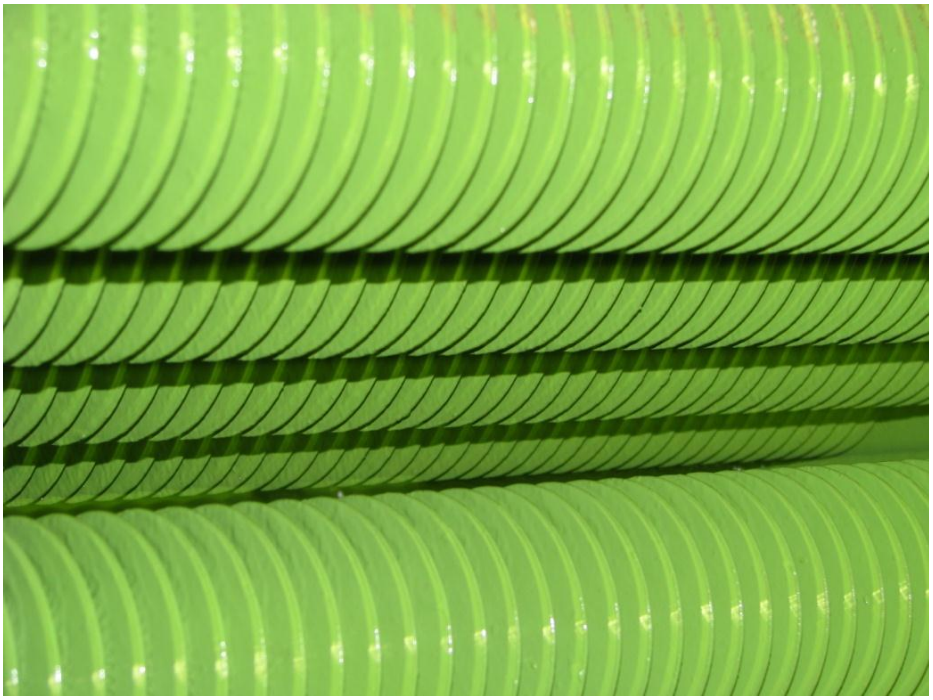

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Figure 10: Coated finned tube economizer bundle

Results

The coated economizer was inspected during scheduled maintenance activities after 12 months of operation.

The erosive environment had resulted in an average coating thickness loss of 25 µm (1 mil) over the 12 month period. (Figure 11) Visual inspection of the coating indicated that there was no degradation of the coating material.

There have been no instances of tube leaks in the economizer since the initial application of the ceramic coating.

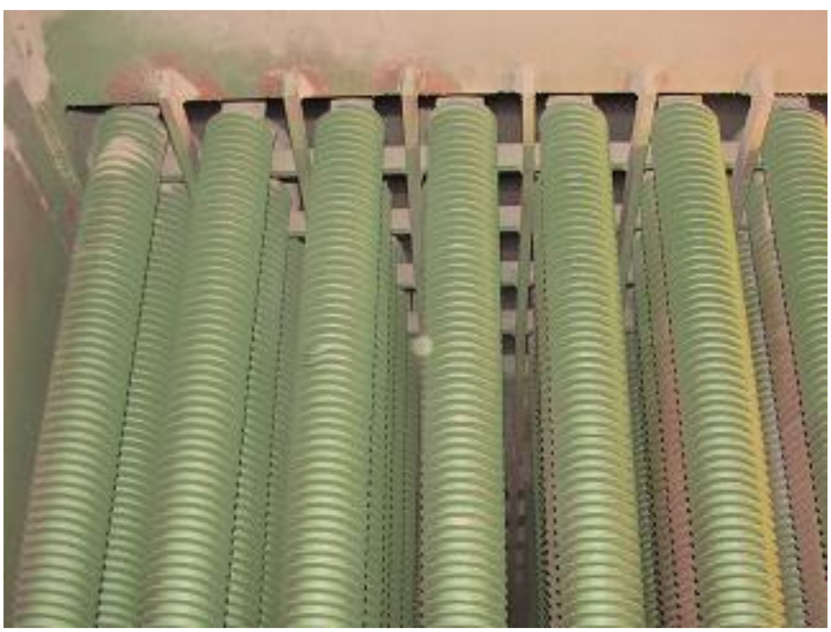

Figure 11: Coated economizer after 12 months continuous service

CONCLUSIONS

Advanced ceramic coatings have demonstrated successful performance in protecting power generation boiler tubes against material loss in high temperature corrosive and erosive environments, and prevented boiler tube failures resulting in forced maintenance activity. Ceramic coating technology is a viable means of protecting boiler waterwalls against sulfidation corrosion in low NOx combustion environments. The use of ceramic coating technology has afforded additional benefits in the operation of the boilers. The ceramic coatings prevent and reduce the agglomeration of slag, allowing the unit to maintain heat transfer efficiency. Ceramic coatings have successfully protected boilers from erosive material losses, eliminating capital intensive component replacement, and significantly reducing the cost and time associated with inspection and non-destructive testing activities. Ceramic coatings contribute to the safe, efficient, and reliable operation of fossil fired power generation equipment.

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