



Efficiency is the Best Alternative Energy

Cokenergy Preventive Maintenance and Operations Plan

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Abbreviations

AM	Arcelor Mittal
APHO	Assistant Power House Operator
CAP	Compliance Assurance Plan
CEM	Continuous Emissions Monitoring
COM	Continuous Opacity Monitoring
ETS	Emissions Tracking System
FGD	Flue Gas Desulfurization system
HRSG	Heat Recovery Steam Generator
ID	Induced Draft
IHCC	Indiana Harbor Coke Company
MWT	Minimum Wall Thickness (per ASME Boiler Code)
NDT	Non-Destructive Testing
OEM	Original Equipment Manufacturer
PHO	Power House Operator
PLC	Programmable Logic Controller
PM	Preventative Maintenance
PMO	Preventative Maintenance and Operations
RCFA	Root Cause Failure Analysis
SO ₂	Sulfur Dioxide
SDA	Spray Dryer Absorbers
SPG	Shock pulse generator (on-line cleaning unit)
STG	Steam Turbine Generator
UT	Ultrasonic Testing
WC	Water Column (gauge pressure measurement unit)

1.0 PMO Purpose/Overview

This document outlines the Preventative Maintenance and Operations Plan (PMO Plan) for the Cokenergy facility which is located adjacent to the Indiana Harbor Coke Company. This plan has been prepared in compliance with Title V Operating Permit No. 089-36965-00383 (Air Permit). This PMO Plan has been developed pursuant to a Consent Decree with the United States, the State of Indiana, Indiana Harbor Coke Company and SunCoke Energy which was entered by the United States District Court for the Northern District of Indiana with an Effective Date of October 25, 2018 (Consent Decree).

As required by the Consent Decree, the PMO Plan details the facility's approach for exercising good operating, engineering, and air pollution control practices and for minimizing emissions and ensuring compliance with the Consent Decree. More specifically, the PMO Plan provides for the steps that Cokenergy will take to allow for the continuous operation (to the fullest extent practical) of the heat recovery steam generators and flue gas desulfurization system between planned maintenance periods and during outages with minimization of emissions. All employees and contractors of Cokenergy are required to follow the provisions detailed in this PMO plan.

2.0 Plant Description

The Cokenergy facility is located in ArcelorMittal (AM) Steel's Indiana Harbor Works in East Chicago, Indiana. The Cokenergy facility is a first-of-a-kind combined heat and power system that uses the waste heat in the flue gas from the metallurgical coke facility to produce steam and power for the AM Indiana Harbor steel mill. AM's Indiana Harbor Works is a large-scale, integrated steel mill. Within the Indiana Harbor Works, SunCoke Energy owns and operates the Indiana Harbor Coke Company (IHCC) metallurgical coke plant, consisting of four batteries of 67 coke ovens each to produce coke for AM's blast furnaces. The coke ovens are non-recovery type, which combusts the coke oven gas in the ovens as it is generated. The coke ovens exhaust the combusted hot flue gas, which must be cooled and environmentally treated, into a series of refractory-lined manifolds to collect the gas.

Cokenergy's waste heat recovery steam generators (HRSGs), arranged four per oven battery, receive and recover heat from the coke oven exhaust gas, producing power-grade steam and cooling the gas in the process. The superheated steam is used to generate electricity in a GE industrial condensing/extraction steam turbine. With the steam and power generated in this process, Cokenergy supplies electricity as well as 300 psig process steam to the AM Indiana Harbor Works. Cokenergy's Flue Gas Desulfurization (FGD) system then also environmentally treats the cooled flue gas, after it passes through the HRSGs, to remove sulfur dioxide (SO₂) and particulate. Flue gas temperatures and flows, and corresponding steam flows, change depending on where a given coke battery is in its coking cycle.

The Cokenergy facility consists of:

- Sixteen (16) heat recovery steam generators (HRSGs), 4 per coke oven battery, which recover heat from the flue gas, and cool it for environmental treatment;
- Flue gas ductwork to manifold the flue gas from the HRSGs to the FGD system;

- Two (2) spray dryer absorber (SDA) vessels to allow mixing of the flue gas with sorbent to remove SO₂ from the flue gas;
- A thirty-two (32) compartment pulse jet, fabric filter baghouse to remove particulate from the flue gas;
- Two induced draft (ID) fans that are responsible for pulling draft through the entire flue gas system from the ovens to the ID fans;
- One GE extraction/condensing steam turbine generator (STG), rated at 95MW, that accepts the generated steam from the HRSGs, and ancillary equipment for operation of the STG, including a 6-cell cooling tower, boiler feedwater heater, and two deaerators.

A schematic of the Cokenergy facility showing its interface with the metallurgical coke plant is shown in Figure 1.

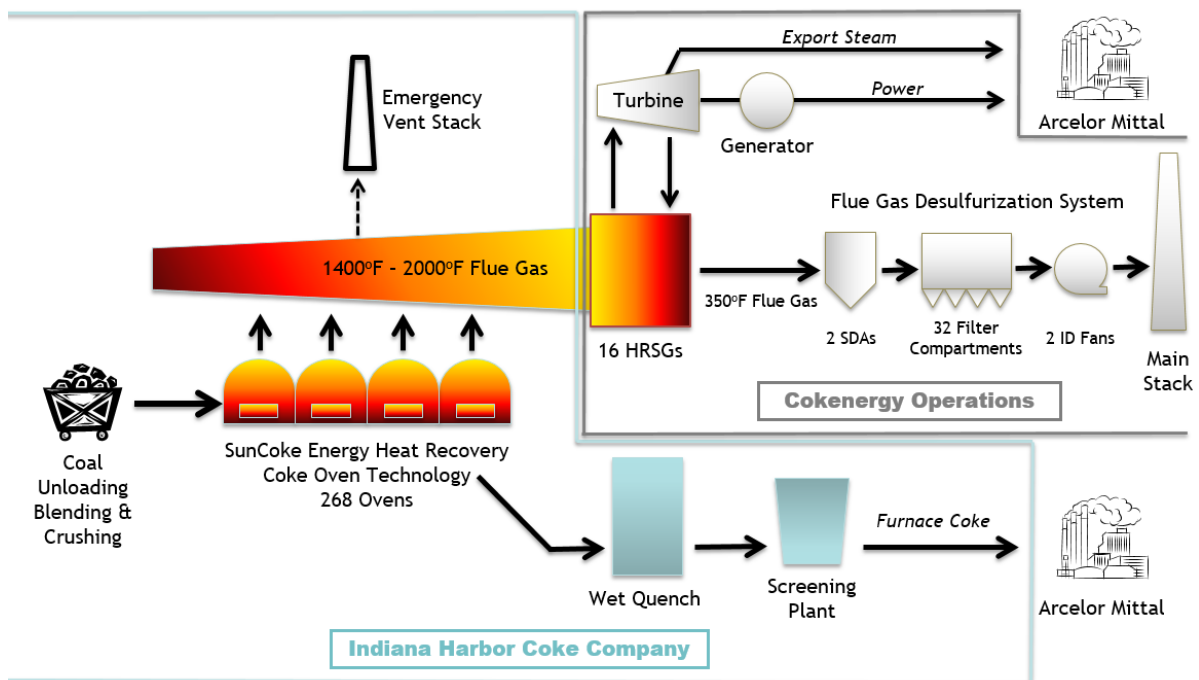


Figure 1 - Cokenergy Facility and Interface with Indiana Harbor Coke Company

The Cokenergy facility is characterized by several important features that play key roles relating to daily operation and maintenance:

- The facility operates in close conjunction with the adjacent IHCC facility. Although Cokenergy and IHCC own and operate separate equipment, the two plants are directly tied together through the flue gas path, with Cokenergy providing the induced draft for both plants, as well as environmentally treating the combusted flue gas from the metallurgical coke facility. The transition from IHCC to Cokenergy ownership is at the entrance to the inlet duct of the HRSGs.

- Induced draft from Cokenergy’s ID fans allows the entire facility to operate at negative pressure (below atmospheric pressure) by providing the motive force to pull flue gas from the ovens through the HRSGs and connecting flue gas ductwork to the FGD unit. A key operational requirement is to sustain target draft at the interface between the FGD and the oven batteries to maintain the required operational draft at the ovens.
- Because IHCC’s metallurgical coke ovens continuously operate, generating flue gas 24 hours a day, 7 days a week, 365 days per year, the Cokenergy facility also has a requirement to continuously operate.
- The FGD system has a 100% availability requirement per the Air Permit. This means that the FGD facility cannot be taken offline as a whole for maintenance. Due to the original design of the plant, this means that some areas of the FGD system are not accessible for routine maintenance.
- Because of the close dependence between the two plants, there is a need for daily communication between the two plants at multiple levels so that maintenance activities can be coordinated, and forced outage events can be more efficiently and quickly resolved.
- Both the Cokenergy and the IHCC facility are contractors to the AM Indiana Harbor integrated steelmaking facility as host. Both Cokenergy and IHCC ultimately provide services to AM – Cokenergy in the form of electrical power and process steam. Due to the electrical configuration of Cokenergy within the larger AM facility, Cokenergy is also dependent on electrical stability of portions of the internal AM electrical grid.

3.0 Plant Maintenance Philosophy

The preventative maintenance approach referenced herein is critical to achieve the necessary level of reliability across the environmental and environmentally-related systems. A proactive approach and the execution of appropriate preventative maintenance is a cornerstone of Cokenergy’s PMO.

The following concepts are implemented throughout Cokenergy’s maintenance plan:

- Incorporate a thorough preventative maintenance plan across all plant systems, with regularly established inspection and maintenance intervals.
- Define maintenance intervals and maintenance processes based on Original Equipment Manufacturer (OEM) recommendations but revise and enhance the preventative maintenance work as necessary based on practical plant experience.
- Use of an industry accepted, web-based Work Order tracking system (Maximo) to identify, schedule, and track all facility planned and break-in work.
- Maintain and regularly review inventory of critical spare parts.
- Involvement and communication of maintenance actions with all Cokenergy management, staff, operators, and contractors.

4.0 Heat Recovery Steam Generators (HRSGs)

The sixteen waste-heat recovery steam generators (HRSGs) at Cokenergy are designed to produce steam from the heat recovered from flue gas generated in a set of co-located metallurgical coking batteries. The HRSGs generate power-grade steam that is sent to an on-site steam turbine generator which produces power for end-customer AM. Each of the HRSGs was originally manufactured by Nooter/Erikson in 1997/1998 and contains both bare and finned tube heat transfer sections as shown in Figure 2. Each HRSG contains a waterwall, evaporator, superheater and separate finned economizer sections as shown in Figure 2. Evaporator and evaporative water wall tubes are rolled into the main upper steam drum and two lower “mud” drums. The HRSGs are unfired, natural-circulation style HRSGs and all steam generation is developed from the waste heat in the fully combusted coke oven flue gas which is drawn through the HRSGs by the draft from the downstream ID fans. The design conditions for the HRSGs are 865 psig pressure, providing superheated steam at 725°F.

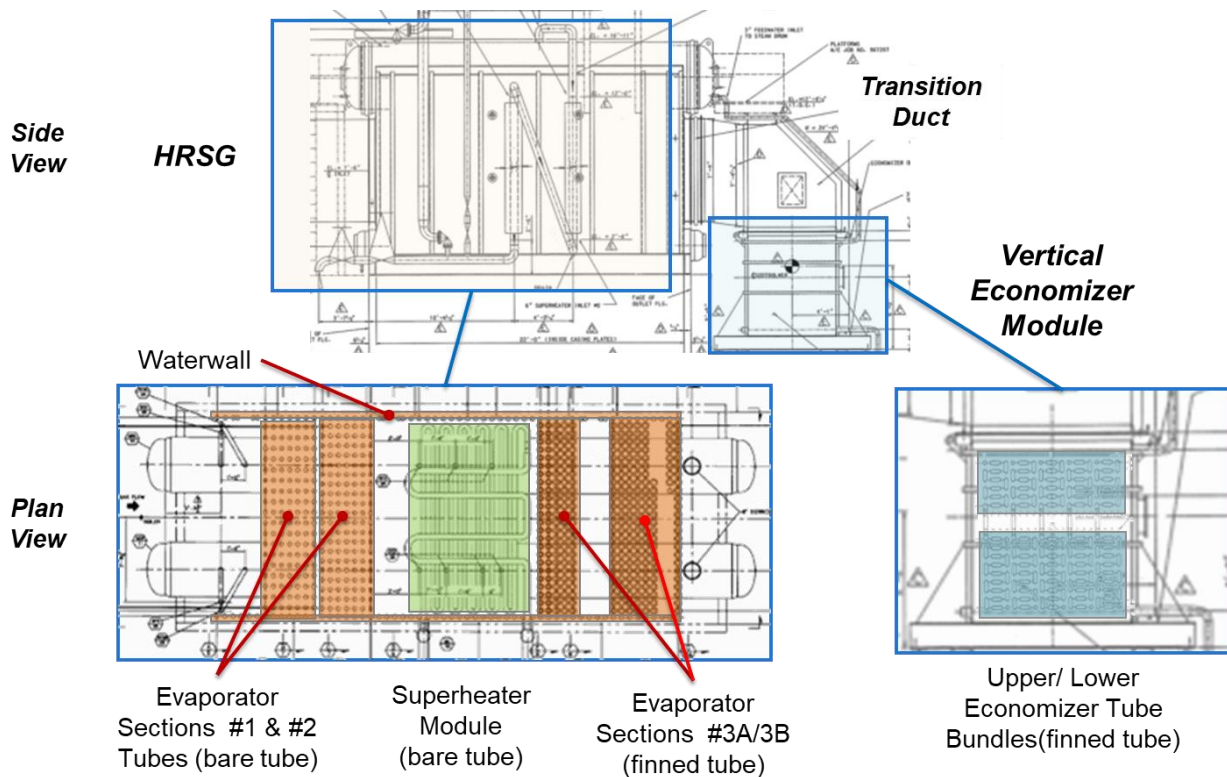


Figure 2 - HRSG Layout and Tube Surface

All sixteen of the HRSGs were retubed between 2010 and 2015, to replace the carbon steel tube materials which were thinned by repeated water washing. Off-line water washing is used to remove gas-side fouling deposits caused by the coke oven gas. Here “retube” means that all carbon steel bare, finned, and waterwall tubes were removed and replaced section by section, resulting in substantially new HRSG heat transfer circuits. The exception for replaced heating surface was the alloy superheater sections, as well as the thick-wall steam drums. Neither of these groups were shown to have experienced any noticeable material thinning.

As part of the retubing process, the specified tube thicknesses were increased, and most finned tubes sections had their fin-to-fin spacing increased to reduce the impact of fouling and improve

both on-line and off-line cleaning. The replacement evaporator tubes, both smooth and finned, have been changed in material specification from SA178D to SA210C. The waterwall has been changed from SA178A to SA192. Cokenergy decided, following consultation with Nooter/Eriksen, to increase the minimum wall thickness for the evaporator tubes from 0.105” to 0.135” for re-tubing. The outer tube diameters have not been changed.

HRSG On-Line Cleaning System

Each HRSG includes an automated on-line cleaning system which operates throughout each day of operation when the HRSG is on-line. The original cleaning system is a steam sootblower system from Clyde Bergemann Power Group. The sootblower configuration incorporates six retractable sootblowers in the horizontal section, two retractable sootblowers between the upper and lower the economizer modules, and four fixed rotating sootblowers, with two above and two below the economizer modules.

Starting in 2017, Cokenergy began replacing the aging sootblower equipment with a pulsed pressure technology called Shock Pulse Generators (SPGs) offered in partnership between the OEM Explosion Power and Clyde Bergemann. The fourteen original sootblowers are removed and replaced by two SPGs which generate a gas-side pressure pulse every one-to-two hours in the HRSG flue gas stream which knocks the deposits from the heat transfer surface throughout the HRSG. This system has been proven with more than 18 months testing and evaluation to be more effective than the original steam sootblowing system. It has an additional benefit that it does not introduce additional moisture into the HRSG flue gas which can result in gas-side corrosion.

Discussion of HRSG preventative maintenance activities will be covered in the following sections. These activities can be broken down in the following areas:

- Inspection, including tube measurements (health data) – normally completed during an annual outage;
- Off-line cleaning – normally completed during an annual outage;
- Routine preventative maintenance scope which can be completed while the HRSG is on-line;
- Routine preventative maintenance scope which requires the HRSG to be off-line, and is normally completed during an annual outage;
- Tube replacement or partial retube outage, which may require outage time in addition to the normal 7-8 days for standard annual outages.

Triggers for the planning and/or initiation of maintenance activities are covered within each section.

4.1 INSPECTION REQUIREMENTS

All HRSGs are scheduled for an annual inspection each year, completed by a third-party team specializing in boiler equipment inspections. Since these are scheduled as part of the annual outage, they do not have a separate trigger.

The inspection team photographs internal condition and key external items requiring maintenance. Internal photos provide a basis for year-to-year comparison of equipment conditions. A comprehensive inspection report is completed by the inspection team for each HRSG. Cokenergy maintains these records onsite.

As part of the inspection process, tube wall thickness measurements are taken using ultrasonic thickness (UT) measurements, or equivalent techniques, at consistent points throughout each HRSG for evaporator, superheater, waterwall sections, and economizer bends to permit routine monitoring of tube condition and wall thickness year-to-year. This process and data will be described further in Section 4.4.

HRSG inspection scope is listed in Table 1.

Table 1 - HRSG Inspection Areas

Inspection Scope	Equipment Covered	Benefit
External As-Is Assessment (Can be completed prior to unit coming offline)	<ul style="list-style-type: none"> • External casing and ductwork • Steel structure • Insulation • Valves/actuators • Piping • Electrical cabinets • Sample cabinets • Sootblowers or SPGs • Expansion joints 	<ul style="list-style-type: none"> • Assess external conditions for historical record • Identify required maintenance items to be completed during planned outage
Internal As-Is Assessment – Gas Path	<ul style="list-style-type: none"> • Waterwall • Heat transfer tubes and finning • Casing • Refractory and insulation • Penetrations • Instruments • Doors • Gas path louver dampers 	<ul style="list-style-type: none"> • Identify and record as-is conditions • Identify required maintenance items to be completed during planned outage • Ability to track as-is condition year-to-year
Internal Post Cleaning Assessment – Gas Path	<ul style="list-style-type: none"> • Waterwall • Heat transfer tubes and finning • Casing • Refractory and insulation • Penetrations • Expansion joints 	<ul style="list-style-type: none"> • Identify required maintenance items to be completed during planned outage • Identify any new operational, wear or damage patterns
Internal As-Is Assessment – Water/Steam Path	<ul style="list-style-type: none"> • Main drum and mud drum interiors and internals • Heat transfer tubes 	<ul style="list-style-type: none"> • Assess water/steam-side condition • Identify adverse impacts from water chemistry
UT tube thickness measurements (Completed in clean condition)	<ul style="list-style-type: none"> • Heat transfer tubes per established locations 	<ul style="list-style-type: none"> • Track tube wear trends • Early identification of any accelerated tube thinning for proactive repair • Develop tube thickness metrics to allow predictive wear trends
Functional Testing (Completed prior to return-to-service)	<ul style="list-style-type: none"> • Instruments • Valves, actuators, control devices • Remote operation of controls • Remove visibility of instruments 	<ul style="list-style-type: none"> • Test and verify all automated fail-safe control prior to return-to-service • Verify visibility of all instruments remotely in the control room prior to return to service

4.2 MAINTENANCE REQUIREMENTS

Gas-side Cleaning Process

Since the retubing of the HRSGs from 2010 through 2015, Cokenergy uses an established buffered water wash process when cleaning the HRSGs. The waterwash is required to effectively clean the HRSGs due to their original design, which include large portions of the heat transfer surface with finned tubes. This design was incorporated in the original concept for the first-of-a-kind application at the coke plant with heat recovery to maintain a small footprint for the HRSGs. However, in practice, the fouling particulate materials generated in the coking process produce deposits high in sulfur, chlorides, and alkali metals which tend to stick to the tube surfaces, and cannot be effectively removed from the finned tube surfaces except by high pressure water washing.

Because the water wash process mixes water with the highly acidic deposit materials, Cokenergy has developed a buffered wash process which mixes water with soda ash to effectively neutralize the combined waste water. The pH levels of both the wash water and the combined waste water are periodically tested to ensure that the generated waste water remains in an acceptable neutral range (pH 6-9) to minimize offline corrosion of the carbon tubes.

The cleaning contractor follows the HRSG cleaning procedure which includes monitoring of the wash and waste water. Cokenergy staff inspect all HRSGs when cleaning is completed by the cleaning contractor to confirm satisfactory condition. If the HRSG Area Manager, or designee, determines the cleaning level is not satisfactory, the cleaning contractor will complete additional washes of the required areas until inspection is acceptable. All tube surfaces are washed with mid-to-high pressure buffered water solution, followed by a final pure water rinse. All tube modules are included in the wash process.

Waste water is collected within the HRSG during the cleaning process, and then processed in Cokenergy's wash water handling area, where particulate is separated from liquid content. Liquid content is then reused as possible for subsequent washes, as long as neutral pH levels can be obtained.

Water washes will be performed at least once a year, as part of each HRSGs annual maintenance outage, where the unit is inspected prior to the cleaning, and then post-cleaning, to best understand year-to-year fouling characteristics and performance of on-line cleaning systems. Cleanings are carried out in planned, staggered pairs during the months of March through October, to avoid freezing conditions. Water washes are performed at least once every 12 months for HRSGs that have been on-line 6-months or more of the 12-month period during a calendar year. If necessary, a HRSG can be taken offline for a supplementary water wash cleaning when online instrument data indicate that the HRSG has become fouled prior to its scheduled cleaning. This may occur due to changes in coke oven coal mixtures, charge weights, or flue gas flow rates from the ovens which tend to carry more particulate from the coking process.

The order for planned HRSG cleanings are triggered based on levels of gas-side pressure drop measured across the combined HRSG and economizer sections using the installed pressure instruments at locations at the HRSG inlet and economizer outlet. A gas-side pressure drop at or

above 12 inches WC indicate a HRSG shall be scheduled for cleaning. Levels between 10 inches to 12 inches WC are used to proactively pre-schedule next units for cleaning.

The Cokenergy standard HRSG Cleaning Procedure is included as Attachment 1.

Routine Preventative Maintenance Scope

In addition to the annual inspection, tube thickness measurements, and cleaning, a set of additional routine preventative maintenance tasks are assigned and completed for each HRSG at regular intervals. Many of these tasks which require internal access to the internal gas path or the internal steam/water side are scheduled during planned annual outages. There is also a routine set of preventative maintenance tasks that are completed weekly or monthly while the HRSG is online.

Annual Maintenance Outage Scope

The tasks included in the annual maintenance outage period are primarily those which require the HRSG to be offline for a planned period, usually for internal access, or for access to steam or water valves which cannot be maintained while the HRSG is on-line. These maintenance tasks are scheduled to include tasks for the HRSG cleaning and the internal as-is and post-cleaning inspections, to minimize time that the HRSG is off-line and so to minimize venting. All maintenance items as listed here are completed to ensure that each HRSG operates safely and reliably and at best efficiency within its design performance range. During each annual outage, each HRSG typically also receives its annual state inspection.

As already noted, an Annual Maintenance Outage for a HRSG includes the following key tasks:

- As-is inspection of the full unit (HRSG plus economizer);
- Water wash of gas-side of full unit;
- Clean inspection of full unit;
- Tube thickness assessment/measurements of full unit.

Additional Annual Outage maintenance tasks also include:

- Inspection and maintenance all steam- and water-side valves and actuators, including packing as required;
- Inspection and maintenance for all gas-side louver damper and isolation damper equipment, including seals and actuators;
- Inspection, calibration, and testing for all instruments, with focus on critical and/or controlling instruments such as drum level transmitters, Eye Hye independent level monitoring, inlet gas temperature thermocouples, and pressure transmitters;
- Inspection and wear-part maintenance for each unit's on-line cleaning system SPG (or sootblowers for units where they are still in use).

Standard annual maintenance outages are planned for 7-8 days. Weather may delay completion of work or return-to-service (wind, lightning).

An example list (for HRSG D4) of standard annual maintenance work orders as scheduled in Maximo are included as Attachment 2 for reference.

It should be noted that whenever possible, unplanned work order maintenance tasks are held and completed during the planned annual outages to minimize venting time for each HRSG. The exception to this is any break-in maintenance which is required to ensure active control and reliable operation and cannot wait until the annual planned outage.

Routine Maintenance Scope Conducted Between Annual Outages

In addition to the annual outage maintenance items, there are routine preventative maintenance tasks conducted more frequently. These routine preventative maintenance activities will be scheduled based upon recommendations by the OEM, and/or based upon practical plant experience, as set forth below.

Routine, periodic preventative maintenance tasks that will be completed when each HRSG is on-line include:

- Continuous drum blowdown, which is maintained at limited continuous daily levels to ensure good water chemistry;
- Monthly intermittent blowdowns from each mud drum, to maintain good water chemistry and eliminate possible buildup of residual in the lower (mud) drums;
- Weekly water/steam samples collected from each HRSGs sample cabinet, to allow for routine testing of water chemistry conditions;
- Completion of daily rounds by Cokenergy APHO, to identify incipient steam or water leaks at valves, as well as routine inspection of external operating equipment such as the on-line cleaning SPG units.

4.3 HRSG HEALTH DATA

As noted in Section 4.2, heat transfer tube thickness data for each HRSG is collected during each annual inspection outage. This tube thickness data, captured at a consistent set of locations for each tube module in each HRSG, form the basis for a set of HRSG health data that is collected, maintained, and monitored year-to-year for each HRSG. This data is used in the manner described below.

The tube thickness measurement data is collected using industry standard techniques for spot ultrasonic tube thickness (UT) measurements. These measurements are collected during each annual outage in a set of standardized locations in each of the HRSG tube module sections: Evaporators #1, #2, #3A, #3B, upper and lower superheaters, membrane waterwall tubes, and upper and lower economizer tube bends. The data is collected after water wash cleaning is completed and following sandblasting of the identified areas to ensure that good UT measurements can be obtained. The UT measurements are taken by the HRSG inspection team, which allows the measurements to be consistently collected by a limited number of technicians familiar with the units.

The UT data for each module of each HRSG is then uploaded and maintained in a digital database system which organizes and stores the data. The database system Cokenergy has selected is the Intertek boiler integrity management software package AWARE. AWARE is customized to collect and store the specific UT measurement data for HRSGs at the identified locations and organize it year-to-year for comparison and evaluation. Through AWARE's integrated analysis

tools, the year-to-year wear rate for the tube thickness can be calculated, and thinning rates can be forecast indicating when minimum tube thicknesses would be expected to be exceeded in specific areas. This capability allows Cokenergy management to then prepare for and take planned action to repair and/or replace tube wear prior to an unplanned and potentially significant failure event. As more tube thickness data is collected year-to-year, the accuracy of this forecasted thinning rate improves, so that planned preventative repairs or limited retubes can be scheduled prior to significant failure events.

An example schematic for the location of UT measurement sections is shown in Figure 3. This schematic shows the AWARE visualization graphic for HRSG C4 Evaporator #1, with all UT tube measurement elevations indicated by a yellow X. At each elevation, three UT thickness measurements are recorded – a left, right, and center positions around the tube, as shown in Figure 4.

UT measurement data is recorded digitally by the HRSG inspection UT technician and converted to a standard MS Excel data table. The data table for each module section is included in the HRSG inspection report, and is also uploaded to the AWARE database, where it can be compared with previous year data.

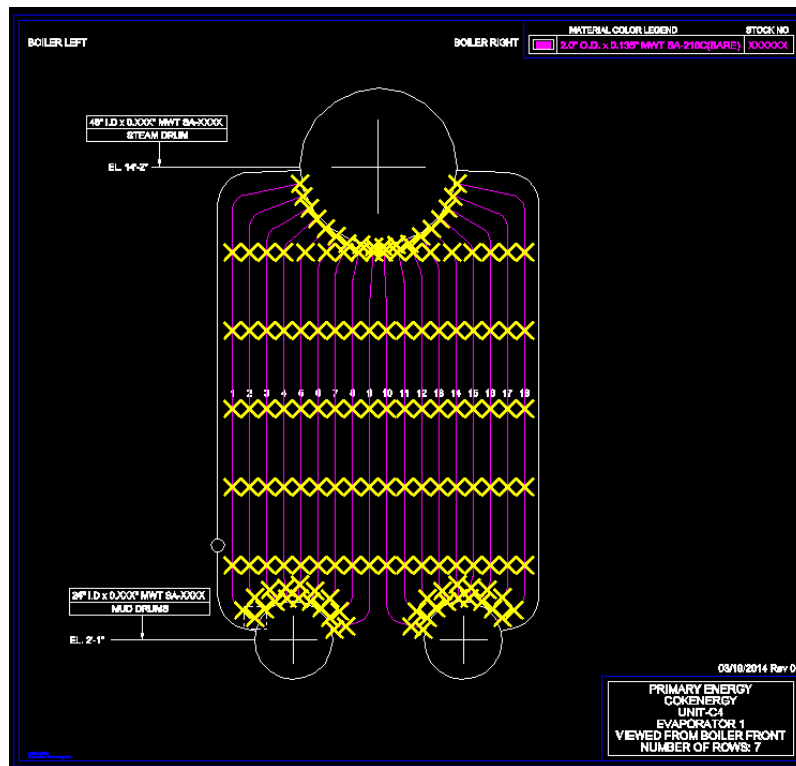


Figure 3 - AWARE Tube Thickness Location Schematic for Evaporator #1

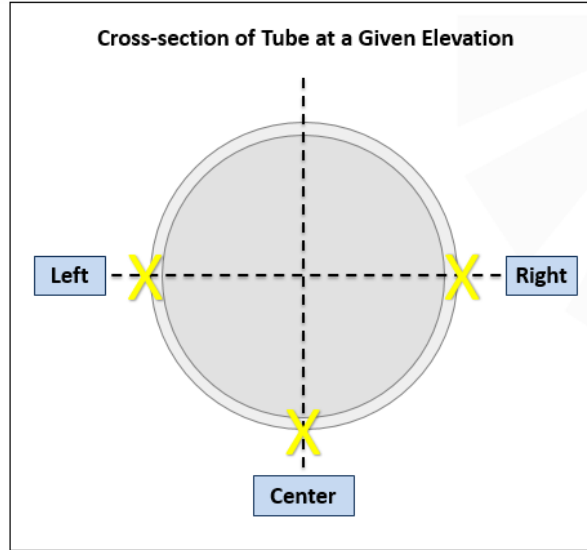


Figure 4 - UT Measurement Positions at Each Tube Elevation Location

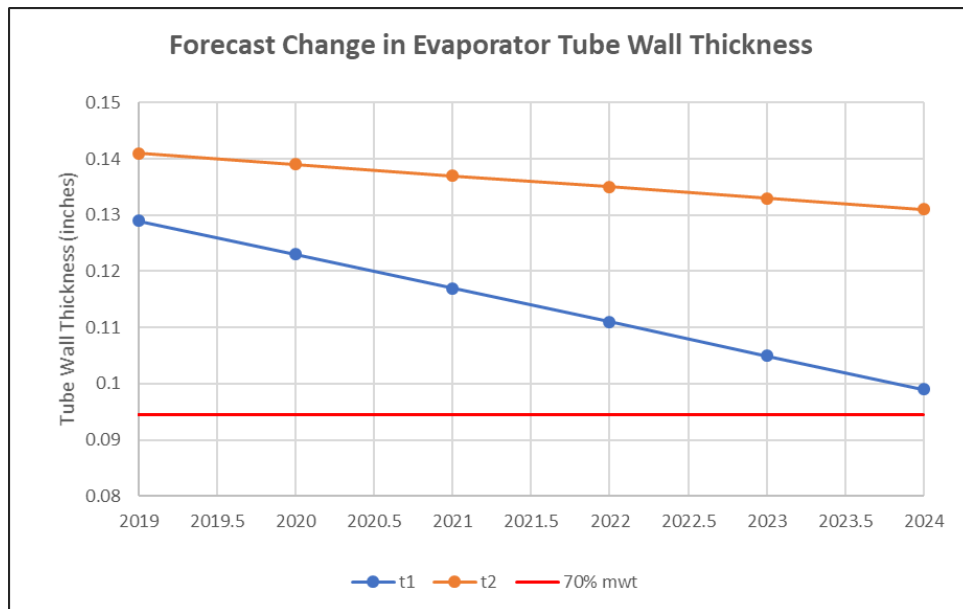
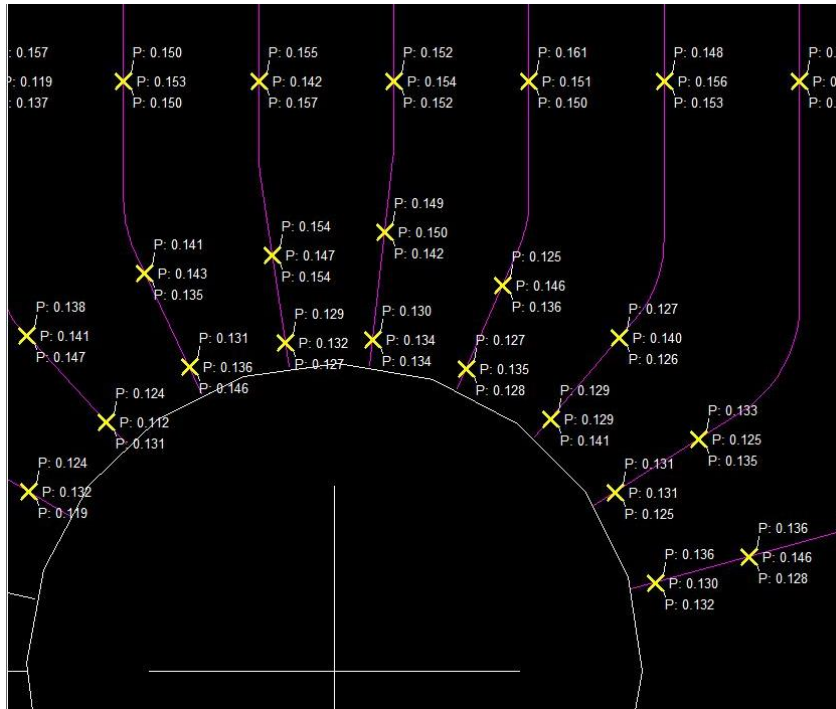
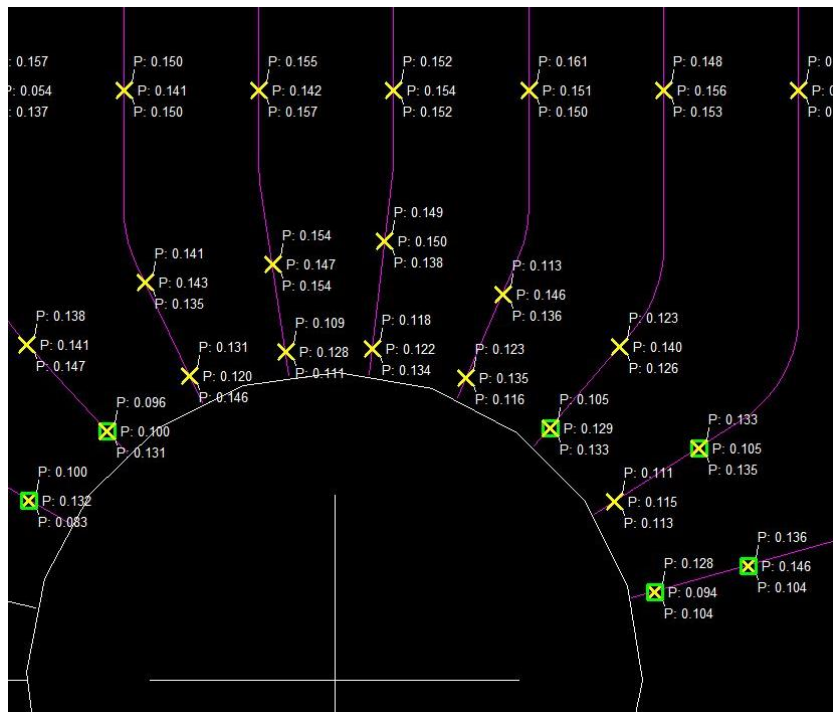


Figure 5 - Year-to-Year Forecast Change in Tube Wall Thickness



Year 2019



Year 2023

Figure 6 - Comparison of Forecast Evaporator Tube Wall Thickness

The HRSG tube UT data collected each year is used to develop tube thinning rates which AWARE can then use to forecast tube thickness levels for each identified tube location. Figure 5 provides an example of forecast tube wall thickness for one tube measurement location. Figure 6 shows an AWARE tube wall section with wall thicknesses for 2019 and 2023.

4.4 CONTROL SYSTEM

The control system for the Cokenergy HRSGs is the IHCC Bailey control system, manufactured by ABB. This distributed control system (DCS) is owned and maintained by IHCC but shared by both IHCC and Cokenergy. The Bailey system is responsible for control and monitoring IHCC controls and instruments on the oven batteries, but also includes controls for each boiler. The shared configuration for the Bailey system is due to the original plant design and the configuration and has been maintained in this format since start-up. The DCS system consists of ten (10) redundant processors that controls the IHCC facility and sixteen (16) Cokenergy HRSGs. Two HRSGs are controlled by one redundant Bailey processor. This processor also controls the associated IHCC ovens that reside below each HRSG. Total of eight redundant processors are used to control sixteen HRSGs. Bailey HRSG controls are then fed through Bailey remote I/O control cabinets located on each HRSG main platform. From each control cabinet to its associated HRSG, Cokenergy has the responsibility to maintain the network and instrument cable infrastructure to ensure reliable HRSG operation.

Cokenergy utilizes a fiber optic connection to communicate from Cokenergy's control room to IHCC's ABB Bailey system. This allows shared human machine interface (HMI) interactions between IHCC and Cokenergy. A schematic for the Bailey DCS system connectivity is shown in Figure 7.

IHCC maintains critical spares for the termination control cards and cabinet power supplies on site, and Cokenergy has access to these spares in emergency situations. In normal day-to-day maintenance situations, if Cokenergy observes operational issues with a Bailey-controlled instrument or control, Cokenergy notifies IHCC staff and coordinates with IHCC to replace and test the identified components.

Cokenergy and IHCC regularly coordinate on Bailey-related maintenance. Loss of Bailey communication and/or failure of a Bailey control component may lead to a HRSG going off-line and venting time for the affected HRSG. Because of this, Cokenergy communicates regularly with IHCC on Bailey maintenance process and schedule. IHCC schedules regular preventative maintenance of the remote Bailey I/O cabinets during planned Cokenergy annual HRSG outages.

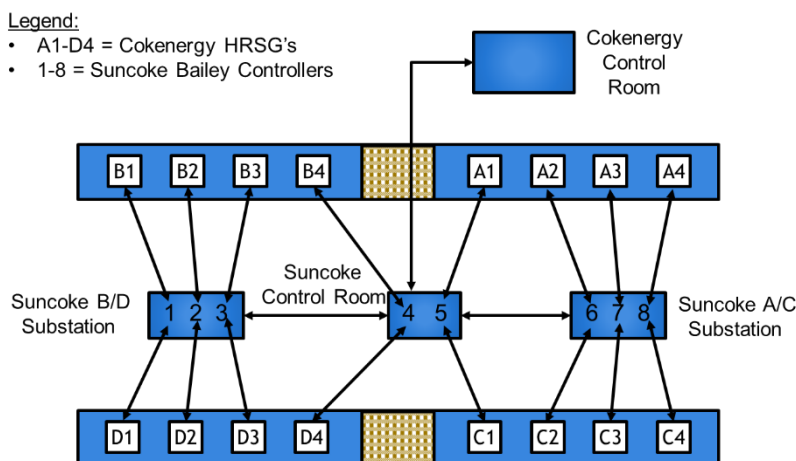


Figure 7 - Schematic of Bailey DCS Configuration for HRSG Control

4.5 ADDRESSING FUTURE HRSG RETUBE REQUIREMENTS

Cokenergy maintains preparedness for possible future HRSG repairs or retubes through the following steps:

- Complete annual inspections, including completion of HRSG health tracking data (Section 4.3)
- Use collected health tracking data maintained in the AWARE database to assess current tube thinning rates and forecast future timing when tube wear rates would require tube replacements. This predictive method permits advance planning of significant retube events by routinely tracking tube condition.
- Maintain one full set of heat transfer surface tubes for each HRSG module on-site.
- Maintain embedded mechanical maintenance crews, including experienced Boilermakers and Pipefitters, for rapid response to forced outages for local and/or unforeseen failure events.

A key goal for the collection of annual tube health tracking data combined with the AWARE database is to maintain thorough monitoring data that is used to assist in early identification of tube wear patterns. The AWARE database, combined with annual visual inspections, provides the primary tool to track tube health and trigger planning for proactive repairs. Identified and monitored localized wear regions will be tracked, initiating planning for repair outages before tube failure events. These repairs can be addressed with limited tube replacements (i.e., “partial retubes” of specifically deteriorated HRSG tube sections) as opposed to large-scale retube of a full HRSG unit that would be required for significant untracked tube deterioration across the full HRSG. The scope would be defined based on the measured tube health data, in combination with visual inspection data and best practice repair methodology.

For the completion of both a partial or complete retube work scope, the existing retube quality assurance specification will be incorporated to ensure high quality process to replace tube sections.

Cokenergy will follow industry standard recommendations for replacing or repairing thinned tube sections as they are identified. An example of standard industry repair criteria is shown in

Table 3 (Reference Babcock & Wilcox Service Bulletin: Tube Thickness Evaluation Repair or Replacement Guidelines 1994).

Triggers for tube replacement or partial retube workscope will include one or more of the following: (note t in Table 3 = mwt as defined below)

Criteria	Tube Wall Thickness (per %mwt trigger)	Action
Measured tube thickness < 70% mwt on single isolated tube (<85% for superheater)	Superheater: 0.1403 inch Evaporator: 0.0945 inch Economizer: 0.0875 inch	Single tube replacement at current outage
Measured tube thickness < 70% mwt on 3 or more tubes in a module (<85% for superheater)	Superheater: 0.1403 inch Evaporator: 0.0945 inch Economizer: 0.0875 inch	Partial retube addressing affected tubes and any necessary adjacent tubes at current outage
Forecast of tube thickness < 70% mwt on single isolated tube within next 12 months (<85% for superheater)	Superheater: 0.1403 inch Evaporator: 0.0945 inch Economizer: 0.0875 inch	Single tube replacement at next planned outage
Forecast of tube thickness < 70% mwt on 3 or more tubes in a module within next 12 months (<85% for superheater)	Superheater: 0.1403 inch Evaporator: 0.0945 inch Economizer: 0.0875 inch	Partial retube addressing affected tubes and any necessary adjacent tubes at current outage
mwt = minimum tube wall thickness per ASME BPVC Section VIII Div 1		

Timelines for partial retubes are dependent on scope and location for repairs and are expected to require between 5-18 days.

Guidelines for Tube Repair/Replacement

Location	Actual Tube Wall Thickness Relative to Percent Specified Wall Thickness, t	Course of Action
1. Furnace Support Tubes and Economizer Stringer Support Tubes	Tubes equal to or greater than 85% t	Monitor thickness
	Tubes less than 85% t	Restore tube wall thickness or replace tube*
2. Economizer, Furnace Wall and other Water-Cooled Tubes	Tubes equal to or greater than 70% t	Monitor thickness
	Tubes less than 70% t	Restore tube wall thickness or replace tube*
3. Superheater, Reheater and Other Steam-Cooled Tubes	Tubes equal to or greater than 85% t	Monitor thickness
	Tubes less than 85% t	Restore tube wall thickness or replace tube*

*It is difficult to restore the wall thickness for tubes below .090 inch due to possible weld burn through and distortion. On Kraft Recovery boilers, Refuse boilers, and boilers operating below 1000 psig the tubes should be replaced when below the ASME minimum wall thickness.

Table 3 - Tube Thickness Repair and Replacement Guidelines

4.6 EMISSIONS MINIMIZATION

Cokenergy will practice emissions minimization through the following steps:

- Completion of routine inspection, cleaning, and preventative maintenance, as described in Sections 4.1-4.2.
- Maintain critical spare parts in-house (inventory) for repairs to return HRSG to service at best possible time.
- Proactive monitoring of HRSG tube health data as detailed in Section 4.3.
- Maintain sufficient dedicated maintenance crew (mechanical and electrical) to allow for best possible repair of break-in maintenance items.
- Minimize venting by combining scheduled work order tasks whenever possible that require a HRSG to be off-line. A key example of this is parallel completion of annual maintenance outage with annual cleaning and inspection work scope.
- Follow established best practice for equipment start-up and shutdowns to minimize long-term impact for cycling of equipment.

Critical spares will be determined based on OEMs recommendations and plant experience. Spare replacement sections for each heat transfer tube module are maintained onsite for efficient repairs in the event of significant tube leak events, allowing shortest possible impact on venting.

Examples of critical spare parts include:

- Replacement tube inventory for all evaporator, superheater, and economizer tubes;

- Instrumentation required for boiler control (e.g. drum level transmitters);
- Primary control valves and actuators (e.g. feedwater flow control valve);
- Start-up and safety valves.

Whenever possible Cokenergy also works to coordinate planned maintenance tasks with IHCC tasks which also require the HRSG to be off-line or vent stack lids to be open. An example of this is the cleaning of the Bailey control system cabinets on each HRSG, that also control IHCC oven damper controls and instruments. Cokenergy regularly communicates planned outage schedules with IHCC, and then IHCC completes annual Bailey cabinet maintenance while the HRSG is off-line for its annual maintenance outage.

5.0 Flue Gas Desulfurization System (FGD)

The Cokenergy Facility is equipped with a Flue Gas Desulfurization (FGD) System that is designed to remove the emissions and particulate matter from the coke oven flue gas before emitting it to atmosphere from the main (201) stack, see Figures 8 and 9. The system is designed to remove sulfur dioxide (SO₂) and particulate matter generated during the coking process as per the original plant design. The FGD system consists of two (2) spray dryer absorber (SDA) vessels followed by two (2) baghouse modules, each with 16 pulse jet fabric filter compartments. Flue gas from the coke oven batteries is first cooled by passing through the HRSGs. This cooled flue gas stream is then manifolded together into flue gas ductwork for each battery, and finally into the single main cross-over duct that delivers the flue gas to the FGD system. Sulfur dioxide scrubbing is accomplished in one or both SDAs, while particulate is removed in all 32 of the baghouse compartments, which are arranged in parallel between the two modules. Finally, the cleaned flue gas is pulled through the two (2) ID fans, exiting at the main stack downstream of the fans.

SO₂ reduction is accomplished by intimately contacting an atomized slurry concentration of calcium hydroxide (Ca(OH)₂) with the SO₂ laden gases while simultaneously allowing the hot flue gases to dry the reaction products. These dry reaction products are collected with the coke oven process particulate in the baghouse. The calcium hydroxide is also known as slaked lime or hydrated lime.

Cokenergy will operate the two SDAs within the FGD system concurrently, to the extent practicable, in a manner that achieves an annual reduction in SO₂ emitted from the facility to 6,165 tons/year. Cokenergy will operate the FGD system in accordance with the PMO Plan to allow equipment inspection, repair, and preventive maintenance, in a manner consistent with good air pollution control practices.

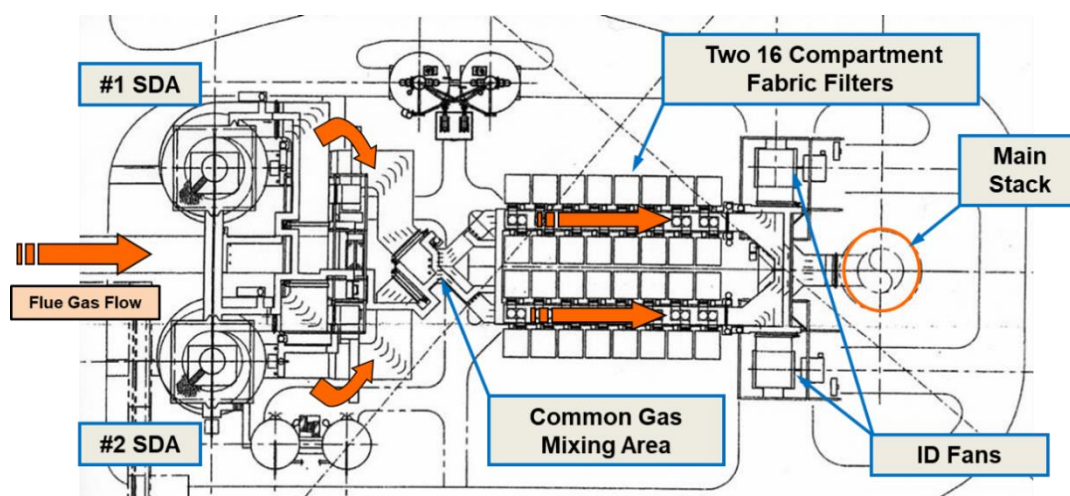


Figure 8 - Plan View of Flue Gas Desulfurization System

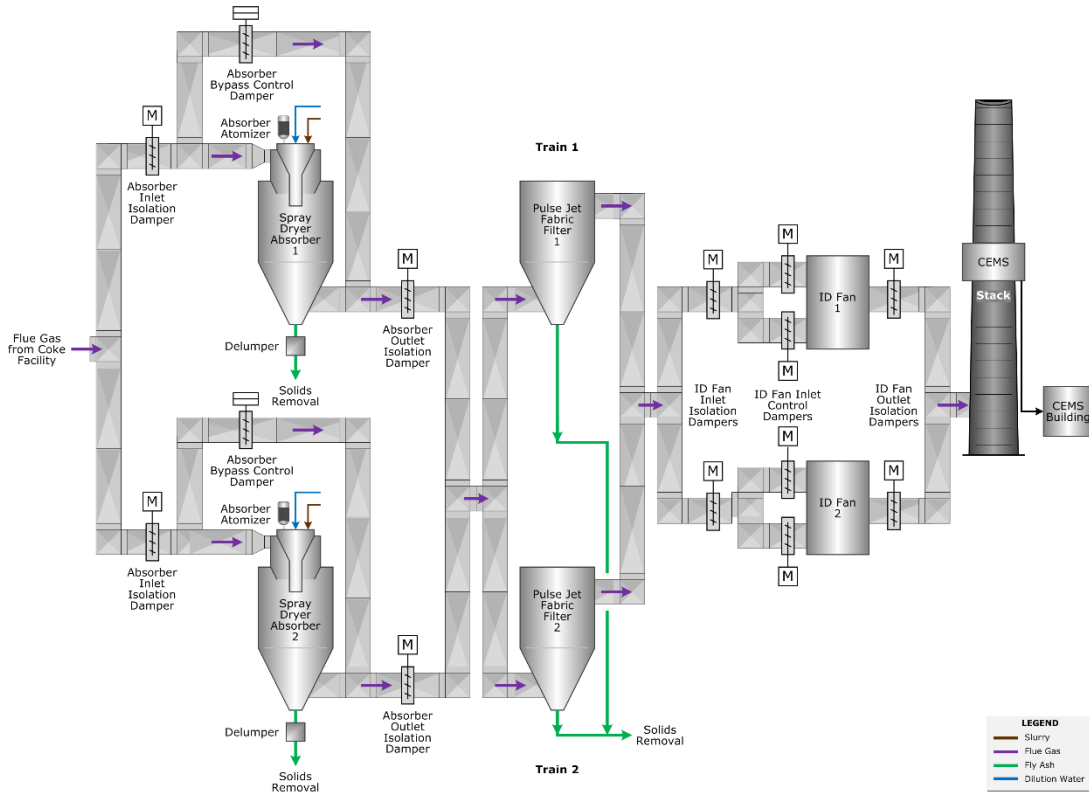


Figure 9 - Schematic of Flue Gas Desulfurization System

5.1 Spray Dryer Absorber (SDA)

The Spray Dryer Absorbers (SDAs) provide the system with the means for effectively removing sulfur dioxide (SO₂) from the flue gas stream by mixing a lime slurry sorbent solution with the flue gas. The reacted particulate byproduct is then removed in the downstream baghouse subsystem.

There are two SDAs manufactured by Marsulex Environmental Technologies (MET) consisting of a large mixing vessel with a gas inlet scroll at the top of the vessel, a rectangular outlet duct near the bottom of the vessel, and conical bottom hopper to collect dropout. Each vessel accommodates a single central spray atomizer located at the top of the vessel, in the center of the gas inlet. The atomizer receives dilution water and lime slurry and sprays this mixture into the surrounding flue gas entering the top of the vessel to complete the SO₂ removal process. Flue gas is accelerated through the scroll as well as a set of fixed turning vanes designed to create a swirling gas pattern as the gas is introduced into the SDA vessel, to benefit mixing. The calcium hydroxide in the lime slurry liquid sorbent, atomized as small droplets, mixes with the swirling flue gas stream. The SO₂ in the flue gas reacts with the calcium hydroxide, forming calcium sulfite and calcium sulfate. The reacted mixture, contained in the small droplets, then dries in the flue gas and is subsequently captured and collected in the downstream baghouse.

Rotary centrifugal atomization is employed for slurry introduction into the hot flue gas. The atomizers are induction motor-driven machines that are designed to operate under high-speed, high temperature, abrasive conditions. Due to these operating conditions, it is critical that the atomizers maintain proper lubrication, cooling, and cleanliness. These conditions are monitored and maintained through the Modicon control system. The atomizer subsystem includes an automatic oil lubrication system, a cooling water system (chiller), and a slurry piping flush system. The rotary atomizers utilize variable frequency drives for start-up, although they are operated at full speed at approximately 8,000 rpm.

Each Cokenergy SDA vessel is sized to treat up to 100% of the design flue gas flow from the oven batteries. The SDAs and all downstream equipment are routinely exposed to corrosive acid gases and require frequent inspection and maintenance to minimize corrosion and maintain the integrity of pollution control equipment. Inspections and maintenance will be performed in accordance with Tables 4 and 5 below.

Operational Modes – Single and Dual

The SDA units can be operated either in single or dual operational modes. For single operational mode, all flue gas transferred from the oven batteries passes through a single SDA vessel, with a single atomizer operating for this vessel. In this mode, the second vessel is isolated using the inlet and outlet guillotine isolation dampers (See Figure 9). In single mode, either SDA - #1 or #2 – may be operated.

In dual mode, both SDAs are operated in parallel, with the flue gas from the batteries splitting evenly between each SDA unit, and all isolation dampers in the open position. In dual mode, two atomizers are in operation – one for each vessel. The flue gas is split between the vessels resulting in reduced gas load to each atomizer, and reduced lime and water flows to each atomizer. This also improves spray drying performance because it results in increased residence times for sulfur reaction and increased drying time for the byproduct particulate.

The ability to operate in single mode is critical to allow preventative maintenance of the SDA vessels. Operation in single mode on one vessel allows the other vessel to be isolated and locked out through standard lockout/tagout process, permitting both the atomizer as well as the interior of the SDA vessel to be accessed for inspection and/or maintenance.

Routine Inspection Requirements

Inspection areas for the SDA include not only the SDA vessel itself, but the atomizer and the control and isolation dampers for each SDA. The vessel internals can only be inspected when the SDA is offline, isolated, and locked out. Redundant seal air fans (2 per isolation damper) ensure that a man-safe mechanical and air seal are maintained to allow entrance to the vessel.

Table 4 - SDA Inspection Areas

Inspection Scope	Equipment Covered	Frequency
Atomizer motor/lower assembly	<ul style="list-style-type: none"> • Atomizer motor • Atomizer lower assembly • Atomizer wheel and tiles • Water and slurry connections • Electrical connections • Instrument connections • Motor/assembly coupling 	<ul style="list-style-type: none"> • Atomizer operational swap • Atomizer motor maintenance (approx. 6500 runtime hours) • Atomizer assembly maintenance (approx. 4000 runtime hours)
SDA Vessel	<ul style="list-style-type: none"> • Manway access doors • Vessel wall interior • Hopper internal walls • Gas scroll ductwork • Scroll flue gas turning vanes • Inlet distribution control dampers 	<ul style="list-style-type: none"> • Annually
SDA Vessel and Key Ductwork	<ul style="list-style-type: none"> • SDA vessel and ductwork corrosion coupons 	<ul style="list-style-type: none"> • Monthly or Bi-monthly
Isolation Dampers	<ul style="list-style-type: none"> • Internal seal surface on isolation side • Expansion joint on insolate side • Seal air fan assemblies 	<ul style="list-style-type: none"> • Annually • Damper surface can be inspected externally in the open position as convenient
Atomizer Chiller (Cooling Water Unit)	<ul style="list-style-type: none"> • Internal seal surface on isolation side • Expansion joint on insolate side • Seal air fan assemblies 	<ul style="list-style-type: none"> • Annually • Damper surface can be inspected externally in the open position as convenient
Atomizer Lube Oil System	<ul style="list-style-type: none"> • Internal seal surface on isolation side • Expansion joint on insolate side • Seal air fan assemblies 	<ul style="list-style-type: none"> • Annually • Damper surface can be inspected externally in the open position as convenient

Routine Maintenance Requirements

As with inspection, maintenance areas for the SDA include not only the SDA vessel itself, but the atomizer and the control and isolation dampers for each SDA, as well as ancillary systems (lube oil and cooling water). The vessel internals can only be inspected when the SDA is offline, isolated, and locked out. Redundant seal air fans (2 per isolation damper) ensure that a man-safe mechanical and air seal are maintained to allow entrance to the vessel.

Table 5 - SDA Maintenance Areas

Maintenance Scope	Equipment Covered	Frequency	Maint. Trigger
Atomizer motor	<ul style="list-style-type: none"> Atomizer motor Electrical connections Instrument connections Mechanical seal Bearings All OEM-identified wear parts 	<ul style="list-style-type: none"> Approx. 6500 runtime hours nominal, 7500 runtime hours max Timing may vary depending on operational loads and conditions 	<ul style="list-style-type: none"> Shop overhaul at designated runtime limits (Freq. Col.) Shop inspection/overhaul for elevated motor vibration levels (> 0.5ips)
Atomizer lower assembly	<ul style="list-style-type: none"> Atomizer wheel, tiles, and nozzles Water and slurry connections Instrument connections Spindle assembly Bearings Lower “spider” water and lime distributor assembly Air vent 	<ul style="list-style-type: none"> Approx. 4000 runtime hours nominal, 7500 runtime hours max Timing may vary depending on operational loads and conditions 	<ul style="list-style-type: none"> Field overhaul (bearings/spindle) at designed runtime limits (Freq. Col.) Field overhaul for elevated vibration levels Shop overhaul and reconditioning at 5-year intervals
SDA Vessel and Ductwork	<ul style="list-style-type: none"> Manway access doors Vessel wall interior Hopper internal walls Gas scroll ductwork Scroll flue gas turning vanes Inlet distribution control dampers Expansion joints 	<ul style="list-style-type: none"> As required 	<ul style="list-style-type: none"> Repair corrosion damage identified as surface rust, wall thinning and/or pin holes, prior to progression Replace exp. joints when found worn or with tear(s)
Atomizer Chiller (Cooling Water Unit)	<ul style="list-style-type: none"> Filters Glycol reservoir/supply Compressor 	<ul style="list-style-type: none"> Quarterly 	<ul style="list-style-type: none"> Service compressor with excessive cycling Service pump at low flow performance
Atomizer Lube Oil System	<ul style="list-style-type: none"> Pump Solenoid Clean oil reservoir 	<ul style="list-style-type: none"> Quarterly 	<ul style="list-style-type: none"> Service pump at low or inconsistent flow or pressure performance Replace solenoid for inconsistent control action
Isolation Dampers	<ul style="list-style-type: none"> Damper internal flex seal assembly Expansion joint Seal air fan assemblies 	<ul style="list-style-type: none"> As required 	<ul style="list-style-type: none"> Replace seals when damaged on inspection. Repair/replace seal air fans at low flow Replace exp. joints when found worn or with tear(s)

It must be noted here that, due to the original design of the MET SDA equipment, there are certain areas that cannot be individually isolated; therefore, they cannot be inspected or maintained internally unless the entire FGD system is offline.

These areas include:

- The inlet flue gas ductwork to the SDAs upstream of the inlet guillotine isolation dampers;
- The SDA outlet ductwork downstream of the SDA outlet guillotine isolation dampers;
- The expansion joints in the noted ductwork.

These areas were last inspected during the May 2015 FGD outage. Inspections of the areas listed above shall be conducted during each scheduled maintenance outage, unless previously inspected within 5-6 years. These outages, generally requiring outage durations between 3-5 days, are scheduled to maintain the integrity of the equipment and avoid catastrophic failure that would result in longer shutdown timeframes and more venting. Repairs identified during the inspection outage will be completed during the same outage event.

5.2 BAGHOUSE

The Baghouse is located downstream of both SDAs and is designed to remove particulate material from the flue gas and is a standard pulse jet fabric filter design. A small portion of the collected particulate is carried from the coke oven process, but the majority of the particulate is formed as a byproduct of the SO₂ removal process. Removal of the particulate matter is accomplished via filter bags arranged in modules that are installed in the flow path between the SDA and the ID Fans. The baghouse consists of 32 filter compartments arranged in two parallel modules of 16 compartments each (1A-1P, 2A-2P). Each compartment is equipped with 272 bags, each with a diameter of 6 inches and a nominal length of about 16.33 ft. In normal operation, flue gas flows to each of the baghouse compartments. As the flue gas passes through the filter bags, particulate accumulates on the outside of the filters and cleaned flue gas exits the baghouse compartments and then continues through the ID fans to the stack. The filter bags are rated to operate continuously at temperatures up to 320°F with short-term excursions of up to 400°F. Gas temperatures to the baghouse are controlled through dilution water cooling introduced through the SDA atomizers, maintaining mixed gas temperature to the baghouse in the range of 250°F – 280°F.

Filter bags are a PPS needle felt fabric, typical for the baghouse industry, which is then dipped in a PTFE emersion bath to improve characteristics of particulate penetration and release. When installed, filter bags are cleaned using a distributed pulsed air system, again typical for industrial fabric filter baghouses. Pulse cleaning for the baghouse compartments is completed on an automated offline cycle. This automated program cycles through the 16 individual compartments in a module when the gas-side pressure drop on a given module reaches a defined target maximum, set for 8.5 inches WC.

It is possible during normal operation to remove 1-2 compartments from service from each baghouse module to allow these compartments to be isolated for internal maintenance.

Inspection Requirements

Several routine inspection tasks are periodically executed for the baghouse. The primary inspection is a quarterly inspection of all 32 baghouse compartments each year by a third-party company experienced with pulse jet fabric filter design, equipment, and operation. This inspection is completed by systematically taking 1-2 compartments offline, isolating and locking out each compartment, followed internal inspection by an experienced crew.

The quarterly inspection assesses and documents:

- Filter bag condition for all compartments;
- Filter cage condition for all compartments;
- Compartment clean gas-side condition for all compartments;
- Compartment dirty gas-side condition, including the compartment hopper, for a portion of the total – typically 8 of 32.

During this compartment-by-compartment inspection, if a filter bag and/or cage is found to be damaged, it is documented, and then replaced. The contractor completing the inspection documents results for all compartments, including any compartments exhibiting damage or unexpected conditions.

Other triggers for baghouse compartment repairs include the following:

- Repeated or unresolved high compartment levels;
- Lower than normal compartment pressure drop recovery following cleaning (normal, expected recovery ranges between 1”-2.5” WC, depending on compartment location);
- Internal compartment wall corrosion marking or penetrations noted upon visual inspection.

Maintenance Requirements

Accessible Components/Areas

The following maintenance tasks are routinely completed through normal subsystem de-energization and lockout/tagout process.

- Annual replacement of filter bags in the eight compartments with the longest runtime since the last filter bag change-out. This process is completed yearly since the PTFE-coated PPS filter bags in use at Cokenergy have been found to have a 3-4 year life cycle for the flue gas conditions experienced at Cokenergy (primarily flue gas oxygen levels combined with gas temperature levels). This annual process replaces the oldest set of filter bags to provide a systematic replacement process that can be scheduled and budgeted year-to-year.
- Replacement of baghouse compartment hopper swing disc assemblies, due to wear part deterioration with use. Swing discs provide the means to evacuate the calcium sulfate byproduct from a compartment hopper following a given number of pulse cleaning cycles. The swing discs are part of each baghouse compartment, and due to the fine, erosive nature of the byproduct particulate, require replacement of key moving wear parts on a 6-12 month average basis to remain in good working order. This is accomplished by swapping a swing disc at the end of its operational cycle with a spare rebuilt disc in inventory.

- Periodic – and typically long-term – repair of internal and/or external compartment weld cracking or localized corrosion locations to maintain air-tight seal and avoid infiltration of ambient air.

Inaccessible Components/Areas

It must be noted here that, due to the original design of the MET baghouse equipment, there are certain areas that cannot be individually isolated, therefore they cannot be inspected or maintained internally unless the entire FGD system is offline.

These areas include:

- The inlet flue gas ductwork between the SDA outlet guillotine isolation dampers and the inlet the baghouse module;
- The dirty flue gas distribution plenum to the compartments for each module;
- The clean flue gas collection plenums from the compartments for each module;
- The inlet damper assemblies for each compartment;
- The outlet poppet dampers for each module;
- The downstream ductwork from the baghouse outlet to the inlet guillotine isolation damper for each ID fan;
- Turning vanes in each of the ductwork areas mentioned above.

Due to lack of access, and inability to isolate while the FGD is in operation, these areas are not routinely inspected. Internal damage in these areas would require a full plant outage to access and repair. It should be noted that these areas were last accessed and inspected in the planned full plant outage in May 2015. Duct and turning vane repairs identified in these areas were repaired at that time. These inaccessible areas and components will be inspected every 5-6 years. These outages, generally requiring outage durations between 3-5 days, are scheduled to maintain the integrity of the equipment and avoid catastrophic failure that would result in longer shutdown timeframes and more venting. Repairs identified during the inspection outage will be completed during the same outage event.

5.3 INDUCED DRAFT FANS

The Induced Draft (ID) Fans provide the motive force to draw flue gas from the coke ovens, through the 16 HRSGs, SDAs, and baghouse compartments, and discharge the gasses out a common exhaust stack. The facility is equipped with two ID fans, situated in parallel downstream of the baghouse modules. The fans are connected by a common header downstream of the baghouse modules so that the fans may operate in tandem, or either single fan may operate and handle flue gas flow from both baghouse modules while the other fan is isolated. The original equipment supplier is TLT-Babcock. OEM support for the fans is now provided through Howden.

The fans are designed for an inlet flue gas flow of 605,090 scfm with an inlet temperature of up to 300°F, with short-term excursions at up to 500°F. The two fans are installed in parallel and are each equipped with two inlet ducts and one discharge duct. The fans discharge into a common header that directs the flue gases to atmosphere through a single exhaust stack. Motor operated isolation dampers are installed upstream and downstream of each ID fan providing positive isolation for maintenance.

During operation both the inlet and outlet isolation dampers are fully open and the inlet louver control dampers modulate to adjust flow through the fans and draft to the upstream portions of the Cokenergy and IHCC facility. During normal operation, both fans are in service.

Each fan is equipped with an identical, independent, lube oil system, used for lubricating the fan bearings. The lube oil system is equipped with two motor driven pumps, one for operation and the other for redundant standby.

Each fan is driven by a 7500 HP, 13.8 kV AC motor. Each motor is equipped with a fixed bearing located between the motor and the fan. The motor is equipped with shaft mounted fans that circulate air to cool the motor windings as it operates. The fan housing is equipped with air filters that prevent dust and contaminants from entering the motor with the circulating cooling air flow. A differential pressure switch (PDS) is installed and will provide an alarm indicating that the filters require service.

For further redundancy, a spare ID fan motor is maintained in “ready-to-install” condition in environment-controlled storage operated by the motor repair vendor. This fan can be transported to the plant for installation within one day, with swap out of motors typically taking two days.

Routine Inspection Requirements

Several standard inspection tasks are routinely completed for the ID fans. However, internal inspections can only be completed when the fan is offline, isolated and locked out. These are completed once a year, or as required based on performance monitoring. Performance data monitored for each ID fan includes inboard/outboard bearing temperatures, inboard/outboard bearing temperatures, and motor winding temperatures. OEM or third-party inspection of the ID fan internals will be completed on five-year cycles. The last inspection of ID fan internals was completed in 2015.

Internal inspection tasks will include:

- Inspection of inlet scroll section
- Inspection of rotor
- Inspection of all guide and turning vanes
- Inspection of motor electrical connection cabinet
- Inspection of motor windings and cable connections
- Inspection of lube oil units
- Inlet and outlet isolation dampers

There may be some inspections during which it will not be possible to inspect one or more of the above items. However, all items that can be inspected will be inspected.

External inspections will be completed as part of normal daily/weekly walkdowns:

- Visual external inspection of lube oil units
- Visual inspection of louver damper linkage
- Visual inspection of all external casing and electrical cabinets
- Visual inspection of inlet and outlet isolation dampers

Routine Maintenance Requirements

Preventative maintenance for the ID fans primarily focuses on routine external maintenance of the ID fan motors and lube oil skids.

Routinely scheduled preventative maintenance shall include:

- Replacement of ID fan motor air filters, at least on a quarterly basis, but also when indicated by filter pressure drop;
- Maintenance of oil level and condition of the ID fan lube oil skids.

Internal ID fan maintenance and repairs if necessary will be coordinated with the appropriate OEM or experienced third-party vendors. In the event of an ID fan motor failure, the standby motor will be requested from the storage facility, the out-of-service motor will be disconnected and lifted from the motor pedestal, and the standby motor will be installed in its place. The failed motor will be sent to the motor repair vendor, and once repaired, returned to storage as the new standby unit.

Internal areas of the ID fan duct work and isolation dampers were inspected in the May 2015 FGD outage. Internal inspections of the areas listed above shall be conducted during each scheduled FGD maintenance outage, unless previously inspected within 5-6 years. These inspection outages, generally requiring durations between 3-5 days, are scheduled to maintain the integrity of the equipment and avoid catastrophic failure that would result in longer shutdown timeframes and more venting. If planned inspections identify required repairs for the ID fans or the respective insulation dampers, these will be coordinated with the inspection outage and are anticipated to require 8-10 days of maintenance outage time.

5.4 CONTROL SYSTEM

The control system for the FGD system is a Modicon PLC system, manufactured by OEM Schneider Electric. This system consists of a Primary and Secondary (Hot Standby) redundant controller and twelve (12) Remote input/output (I/O) racks. The Modicon controls the facility's ID Fans, Baghouse, Spray Dryer Absorbers, and FGD auxiliary support systems. The Modicon control system is the original FGD control system, but components were upgraded in 2015. Improvements implemented in the upgrade include new controllers along with replacement of obsolete coaxial communication cables to remote I/O locations. New controllers have enabled improvements to automation software as prior to 2015, the original controllers were fully utilized, preventing programming and automation enhancements. Remote I/O communication coaxial non-redundant cables were replaced with redundant, self-healing, fiber optic cables.

The Modicon configuration diagram, Figure 10, shows the current configuration of this system. Racks 1A and 1B are the Primary and Hot Standby Controllers (CPU). Racks two through twelve are spread out through the facility as remote I/O racks controlling their designated descriptions. Redundant fiber optics cables provide reliable means of communications to these racks. In addition, multiple human machine interfaces (HMI) provide redundancy for operations to run the facility.

It is important to note that the FGD control system plays a key role for overall availability and reliability of the Cokenergy plant. If the control system would fault on both PLC controllers, all FGD controls would be inoperative, including both ID fans. If the ID fans are not maintaining

draft through the flue gas system, then flue gas is not pulled through the HRSGs or through the FGD system. Without flue gas, all HRSGs are offline, with IHCC stack lids opening automatically to maintain natural draft to the ovens. Because of this requirement maintenance of the Modicon PLC system has high importance.

Cokenergy will follow the Modicon OEM recommended preventative maintenance tasks for the FGD PLC control system listed below:

- Maintenance of daily operating system back-ups for the PLC controllers, in the event one unit experiences a fault and must be reloaded;
- Firmware upgrades, as available and provided by the OEM;
- Programming software updates, as available and provided by the OEM;
- PLC processor memory optimization, periodically per OEM recommendations.

The first three of these preventative maintenance activities can be completed with the redundant PLC system on-line, working between the primary and secondary PLC controllers. This allows the PLC to be updated with operational system updates as the OEM identifies and develops revisions. Cokenergy follows these guidelines to ensure system reliability.

The final maintenance recommendation requires that both primary and secondary PLC controllers be taken offline for the optimization process. The OEM recommends this optimization after significant software, programming, and/or hardware upgrades are completed on the Modicon. Because of on-going system improvements to both hardware and automation programming, Cokenergy anticipates the need to complete an optimization process approximately every two years. This requirement will continue to be evaluated in coordination with the OEM, due to its implications on venting and SO₂ compliance, and the PMO Plan will be updated as needed to reflect changes in the optimization process.

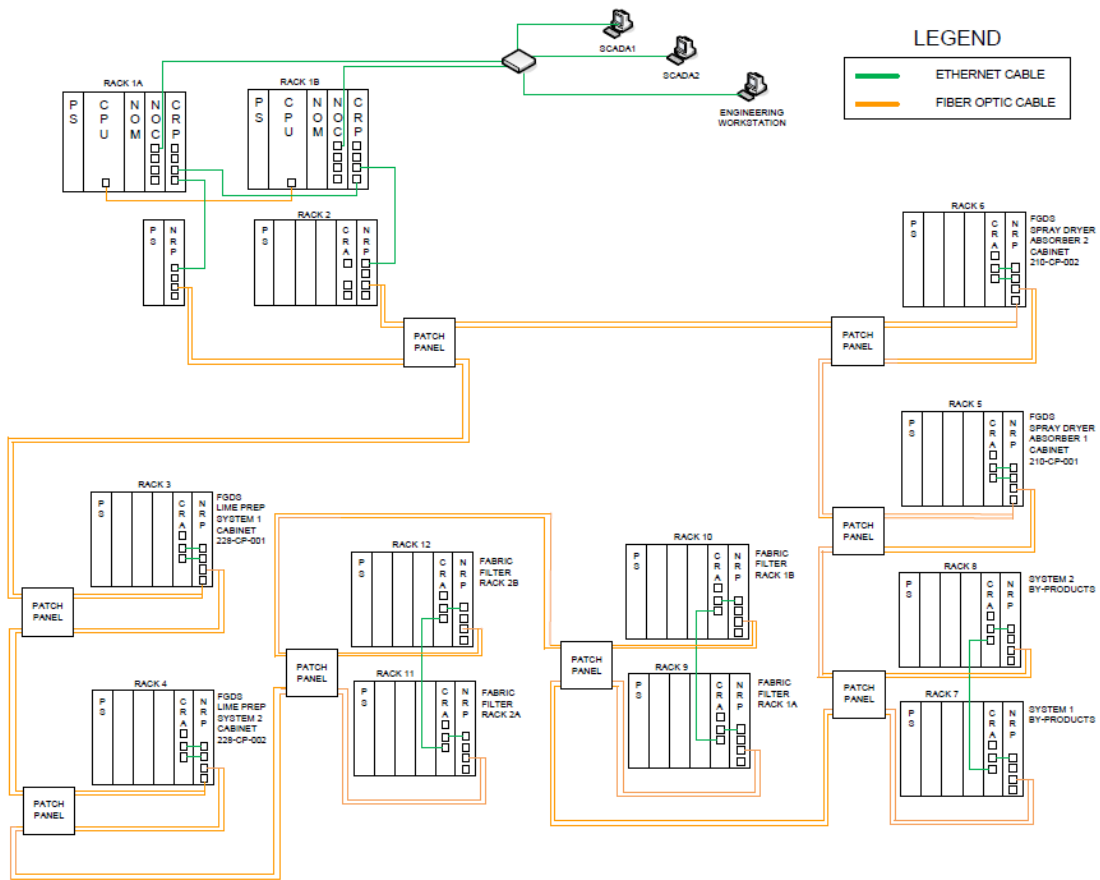


Figure 10 – Schematic of FGD Modicon Control System Configuration

6.0 Continuous Emissions Monitoring System (CEMs)

Pursuant to Section D.1.9 of Cokenergy’s Title V permit, the concentrations of SO₂ and O₂ must be monitored from the stack and the SO₂ emission rate from the main stack. Cokenergy must provide the output from the CEMS to IHCC for utilization in the emission tracking system. Opacity monitoring is required in accordance with Section D.1.10 of the permit. In accordance with paragraph 19 of the CD, Cokenergy has installed a permanent flow monitor to measure the volumetric flow rate of the main stack.

The CEMS is an integrated system manufactured by Monitoring Solutions, Inc. Figure 11 presents a simplified illustration of CEMS equipment installed on the stack. The equipment configuration in the CEMS equipment shelter is included in Attachment 3.

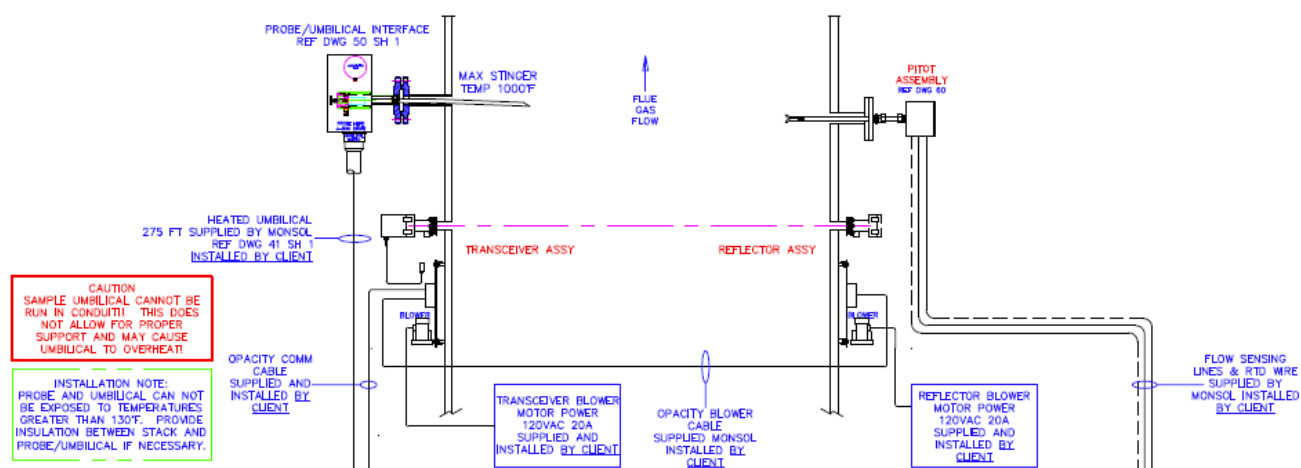


Figure 11 - CEMS Stack Layout

Flue gas is extracted from the stack and is protected by maintaining the flue gas temperature as it is being transported. It is also necessary to prohibit the flue gas sample from coming into contact with any material that could alter the concentration of the sample until conditioning is complete. A heat trace installed in the umbilical, regulated by a rack mounted temperature controller, keeps the sample gas at a desired temperature above 220°F. The stack gas first comes in contact with a cell to measure the oxygen (O₂) concentration on a wet basis prior to entering the Sample Gas Conditioner.

As the extracted gas enters the Sample Gas Conditioner it is cooled by a thermoelectric cooler (to remove moisture) with a temperature set point of +4°C, run through a particulate filter to remove any other sample contaminants and delivered to the gas control panel. Rotometers control and monitor the sample flow rate of dry gas to the SO₂ and O₂ analyzer. A gauge is provided to monitor sample pressure. Each analyzer draws the required amount of sample from the sample manifold. The gas control panel also controls the flow of excess sample to the sample vent.

COMS (Continuous Opacity Monitoring System) - monitors the opacity of particulate flowing through a stack or duct. The system measures opacity as a percentage of light passing through the gases compared to the reference light beam originating from source. It consists of four major components: the Transmissometer, the terminal control box, the air-purging system and the remote-control unit and data acquisition equipment. The Transmissometer component consists of an optical transmitter/receiver (transceiver) unit mounted on one side of a stack or duct and a retro reflector unit mounted on the opposite side. The transceiver unit contains the light source, the photodiode detector, and the associated electronics. The transceiver uses a single-lamp, single detector system to determine opacity. An LED light source is modulated electronically at 2 KHz to eliminate any ambient light interference. The modulated beam is configured to alternately produce reference and measurement signals so that the effects of variations in the optical and electronic components of the opacity monitor are minimized.

The display terminal control box mounted beside the transceiver unit provides on-stack readout of the opacity output from the transceiver and can be used as a diagnostic tool.

The air purging system serves a threefold purpose: 1) it provides an air window to keep exposed optical surfaces clean; 2) it protects the optical surfaces from condensation of stack gas moisture; and 3) it minimizes thermal conduction from the stack to the instrument. A standard installation has one air-purging system for each of the transceiver and the retro reflector units. The remote-control unit communicates with the remote display unit via an RS 422 cable.

CEMFlow – A simple S-type pitot tube is utilized to measure differential pressure as gas flows up the stack. High and low pressure is measured, then utilized to calculate stack velocity (using the Bernoulli equation). Multiplying by the stack diameter converts this velocity to flow. The stack gas temperature is also monitored using a standard thermocouple.

CEMCON (Continuous Emission Monitoring Controller System) - receives and stores data generated by the CEMS and automatically controls CEMS operations such as system purge, sample air flow, calibration, and detection of alarm conditions. In addition, it provides the communication link between CEMS and CEMDAS. The CEMCON system consists of a PLC controller with power supply and a multifunction keypad for operator interface.

CEMDAS (Continuous Emission Monitoring Data Acquisition System) - retrieves the data stored by the CEMCON and performs the required calculations to determine if the readings are within required limits. The system is designed to provide alarm messages and signals in the event the results do not meet applicable requirements. CEMDAS can also generate the required reports used in EPA audits and in evaluating system operability.

The emissions monitoring equipment surveillance and maintenance requirements are included in the site QA/QC plan.

Emissions Tracking System (ETS)

In order to calculate SO₂ emissions from the Indiana Harbor Coke Company (IHCC) emergency vent stacks and calculate the combined SO₂ emissions from IHCC and Cokenergy, IHCC utilizes ETS. The ETS system utilizes coke production data, HRSG steam production, vent lid status, and coal analytical data to calculate the potential SO₂ emissions from venting using a material balance. Cokenergy provides actual sulfur dioxide data from the stack CEMS to allow for the calculation of site SO₂ emissions

With the addition of the flow monitor on the Cokenergy stack (201), the IHCC ETS system is in the process of being updated pursuant to paragraph 21 of the CD. Once complete the SO₂ emission will be calculated using the actual stack flow rate.

7.0 Emissions Minimization Efforts with IHCC

Because of the close dependence between the two plants, there is a need for daily communication between the two plants at multiple levels so that maintenance activities can be coordinated, and forced outage events can be more efficiently and quickly resolved. Cokenergy will make every effort to coordinate with IHCC and conduct required maintenance during scheduled bypass venting events.

In the event of bypass venting in excess of the daily venting limit of 19%, Cokenergy, working in conjunction with IHCC, will minimize emissions to the extent practical as set forth in paragraph 17 of the Consent Decree.

8.0 Electrical Conditions and Responses to Electrical Distribution Failures at AM

The AM Indiana Harbor integrated steel facility, the IHCC metallurgical coke plant, and Cokenergy form an interconnected electrical distribution system. This is important to note for this plan because changes to the electrical conditions outside of Cokenergy can impact the operation and availability of Cokenergy's equipment.

Cokenergy is interconnected with the AM Indiana Harbor electrical distribution grid by two 69kV transmission lines – 2RX04 and 2RS03. These supply redundant power to the Cokenergy facility, and are each stepped down to 13.8kV to supply the full Cokenergy facility equipment on two 13.8kV bus lines. If one of these 69kV lines is down, the internal tie breaker between the two bus lines can be closed to power both sides of the bus, maintaining power to the entire Cokenergy plant. Power generated by Cokenergy's steam turbine generator similarly is stepped up from 13.8kV to 69kV and is supplied to the AM Indiana Harbor grid by 2RS03.

If both of the 69kV bus line are down, due to issues with the AM Indiana Harbor electrical grid, then the Cokenergy facility will be without operating power and all equipment will be offline. Because power to IHCC is supplied through the Cokenergy 4160V bus lines to IHCC, this will also mean that IHCC is also without operating power.

It is important to note that the Cokenergy facility is not configured electrically to operate as an independent electrical “island” within the AM Indiana Harbor electrical grid. This means that even if all Cokenergy equipment and systems are in operational order, if electrical supply from the AM Indiana Harbor grid fails, Cokenergy facility will be offline until power can be restored to at least one of the 69kV bus lines.

This failure in electrical distribution has occurred a limited number of times in recent years due either to (1) lightning strikes on key AM electrical grid components, or (2) equipment failure on key AM electrical grid components – typically transformers.

Under these circumstances, Cokenergy will follow these standard protocols:

- (1) Cokenergy management remains in regular communication with AM Utilities counterparts to best coordinate return-to-service activities;
- (2) Cokenergy management remains in regular communication with IHCC counterparts to best coordinate return-to-service activities;
- (3) Cokenergy staff prepares all equipment, and if necessary makes required repairs, to allow best possible return-to-service time, with emphasis on environmental control systems;
- (4) For long duration events, Cokenergy will discuss and coordinate emissions minimization efforts with IHCC.

9.0 PMO Plan Management and Revisions

Per the Consent Decree, Cokenergy and IHCC have agreed to implement a Compliance Assurance Plan (CAP) in the PMO Plans to address potential periods of higher production levels. IHCC is responsible for monthly evaluation of production and sulfur content of dry coal to identify when they exceed both of the levels indicated in the following chart in two consecutive months.

“High Production Level Months”

Average Monthly Sulfur Content of Dry Coal	Between 0.7% and 0.9%	>0.9%
Average Monthly Tons of Dry Coal Charged	144,000	128,000

IHCC and Cokenergy will jointly evaluate whether subsequent High Production Level Months could cause exceedances of PM or SO₂ limits in the Companies’ Permits and the Consent Decree, and if so, the steps that will be taken to prevent those exceedances. Cokenergy is responsible for evaluating the CAP actions related to operability and control of the FGD and HRSG equipment. The CAP is required to be submitted once prepared or updated and for any instance when the CAP had to be implemented to ensure compliance with PM or SO₂ limits.

Any update to the PMO Plan or failure to follow guidelines identified in the PMO Plan will be reported to USEPA and IDEM in a semi-annual progress report.

PMO PLAN REVISION HISTORY

Revision #	Date	Description of Change	Approved By
0	6/28/2018	Initial plan development	<i>D. Pack</i>
1	11/18/2018	Incorporate governments comments	<i>L. Ford</i>
2	12/13/2018	Incorporate final comments from USEPA and IDEM	<i>L. Ford</i>

Attachment 1 – HRSG Cleaning Procedure

	Document: CE-SOP-300-020	
	HRSG Cleaning	
OPS Document	Issue Date: 06/27/2018	Page 1 of 2

1. Purpose

This HRSG cleaning procedure was created in order to provide clear guidelines and steps to follow when cleaning a HRSG.

2. Scope

This procedure applies to the Cokenergy facility operated by Primary Energy, its employees, as well as independent contractor personnel and visitors.

3. Procedure

3.1 Pre-cleaning setup

- 3.1.1 Load tanker truck with condensate from pump house or water from the HRSG wash facility tank if filtered wash water is available. See *CE-EHS-833-A05-00 Load Truck with Filtered Wash Water* for details on how to load the tanker truck with filtered wash water.
- 3.1.2 The pH of the water should be adjusted using soda ash. The target concentration of the soda ash solution is 7%, which is achieved by combining eleven (11) 50-pound bags of soda ash with 950 gallons of water. Once the soda ash is mixed in the truck the pH should be verified to be in the range of 11-12.

3.2 Boiler Cleaning

- 3.2.1 Verify boiler has been locked out and opened, and that Cokenergy Management has completed an "as-is" internal inspection. Obtain approval from Cokenergy Management to begin the cleaning.
- 3.2.2 All boiler doors should be in place on the boiler other than the boiler door that will be entered. This is to prevent any water from leaking out the other doors during the wash.
- 3.2.3 Install a vacuum hose in the door that will be entered to vacuum out the water as the boiler is being washed.
- 3.2.4 The amount of water in gallons taken out to the boiler for the wash is to be documented.
- 3.2.5 Wash the boiler with high pressure, per cleaning contractor's procedures, using the soda ash mixture.
- 3.2.6 Randomly check the pH of the wash water during the wash to verify the pH is between 6 and 9.
- 3.2.7 The waste water vacuumed from the boiler should be checked for pH before returning the water to the Boiler Wash RCRA Facility. The truck operator should adjust the pH with additions of Soda Ash until the water is brought to neutral within pH range of 6

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and 9.

- 3.2.8 Once pH is verified in accordance with 3.2.7 above, transfer the waste boiler wash water to the Boiler Wash RCRA Facility. Unload the waste wash water at the facility in accordance with EHS Procedure *CE-EHS-833-A01-00 Boiler Wash RCRA Facility-Appendix 1 Unload Truck to Hazardous Waste Dewatering Box*.
- 3.2.9 Prior to final rinse, the HRSG Area Manager or designate will complete an inspection of clean condition to verify the wash is complete.
- 3.2.10 Final rinse of the entire boiler and economizer with pure water is done once the initial wash is completed and inspected by Cokenergy Management.
- 3.2.11 Once the boiler wash has been completed and all the waste water has been transferred to the Boiler Wash RCRA Facility, the amount of the waste wash water returned to the facility is to be documented. This is to determine how much of the water that was used for the boiler cleaning has been recovered.

4. Implementation

- 4.1 This procedure is effective upon the issuance date and upon any subsequent revisions.

5. Exceptions and Variances

- 5.1 Any variances to this Standard must be authorized by the General Manager. Designates may be appointed to cover during absences. This approval may be electronic or in hard copy form.

6. Document Control

REVISION HISTORY

Revision #	Date	Description of Change	Written by	Approved By
01	06/27/2018	Approve Final Revisions	<i>R. Wranosky</i>	<i>K. Kaufman</i>

Distribution

Electronic Copies	S: Job Procedures\HRSGS\ R: Latest Procedures
Paper Copies	none

Document Responsibility

Owner	R. Wranosky
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Attachment 2 – Example HRSG Maintenance Outage Work Orders

Example of standard package of maintenance Work Orders (WO) for annual HRSG outage, for HRSG D4.

WO list is exported in MSEXcel format from Maximo

HRSG Complete Offline Task Packet		HRSG D4		
PM	Description	Asset	Location	Status
1086	D4 Boiler Cleaning	300-CL-D4	HRSG D4	ACTIVE
1149	Boiler Main Power Transformer Cleaning - D4		HRSG D4	ACTIVE
15 DLAD4	Drum Level A Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 DLBD4	Drum Level B Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 EIPD4	Economizer Inlet Pressure Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 EOPD4	Economizer Outlet Pressure Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FCVD4	Boiler Feedwater Control Valve Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FGDD4	Flue Gas Damper Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FIGD4	Flue Gas Iso Guillotine Damper Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FWFD4	Boiler Feed Water Flow Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 FWMD4	Feed Water Isolation MOV - D4	300-IN-D4	HRSG D4	ACTIVE
15 INPD4	Boiler Inlet Pressure Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 SDPD4	Steam Drum Pressure Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15 SVVD4	Start-up Vent Valve Calibration - D4	300-IN-D4	HRSG D4	ACTIVE
15-GR-D4	BLR Main Steam Block Valve Lubrication, 1Y	300	HRSG D4	ACTIVE
15-IN-D4	Inspection of D4 boiler	300-BR-D4	HRSG D4	ACTIVE
15DUCTD4	Louver and Casing Repairs D4 boiler cleaning	300-DU-D4	HRSG D4	ACTIVE
15FNTSD4	Boiler Functional Test - D4	300-IN-D4	HRSG D4	ACTIVE
15GUID4	Boiler Guillotine damper PM D4	300	HRSG D4	ACTIVE
15INSD4	Inspection Support and Prep for D4	300-MM-D4	HRSG D4	ACTIVE
15INSPD4	Boiler Cleaning and Inspection Checklist - D4	300-D4	HRSG D4	ACTIVE
15MOV-D4	Feedwater MOV Greasing PM	300-VA-D4E	HRSG D4	ACTIVE
15PFNTD4	Boiler Pre-Start Functional Test - D4	300-IN-D4	HRSG D4	ACTIVE
15REFD4	Refractory work during boiler outage D4	300-DU-D1	HRSG D4	ACTIVE
15SUPD4	Inspect any bad superheater shields D4	300-BR-D4	HRSG D4	ACTIVE
15VLV-D4	D4 Boiler Valve PM	300-PI-D4	HRSG D4	ACTIVE

Attachment 3 – CEMS Shelter Layout

