Proceedings of the ASME Turbo Expo 2010
June 14-18, 2010, Glasgow, Scotland, UK

GT2010-23814

AN INNOVATIVE APPROACH TO EMISSION REDUCTIONS & HEAT RECOVERY – COMPLY UNITS

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ABSTRACT

Emissions from power plants are increasingly becoming a global concern that is forcing countries to set tougher and tougher standards for meeting regulations. Compliance with these requirements comes at a cost – resources required to install and maintain the necessary equipment that is often exacerbated by a reduction in efficiency. These harmful emissions that are products of combustion (POC) are typically classified as NO_x, SO_2, CO_2, UHC (unburned hydrocarbons) and Particulate and sometimes heavy metals like mercury, arsenic, etc. Currently there are specific methods available for reducing each of these emissions individually but there is no single system in use that can remove all these unwanted emissions simultaneously – at least not until now. With the proposed system, all these emissions can almost be entirely eliminated from the flue gases concurrently. The process essentially consists of ozone injection for NO_x conversion, fogging spray mixed with hydrogen peroxide solution for SO_2 conversion and condensing these along with other pollutants over coils to remove all pollutants from exhaust gas stream. As a result, the NO_x and SO_2 end up as nitric and sulfuric acid in the wastewater stream collected at the bottom of the unit. In addition, UHC and particulate are also removed during the condensation process along with some carbonic acid resulting from dissolved CO_2. This waste water can then be treated accordingly and recycled. Another major advantage of this process is the heat absorbed by circulating water in the condensing coils that can be effectively utilized to improve plant performance and overall thermal efficiencies.

INTRODUCTION

The major objective of this paper is to present a technique of removing harmful and undesirable pollutants from the exhaust gas steam of boilers. This process is applicable to all kinds of boilers - natural gas, coal-fired, oil-fired, wood-fired, bio-fuels, refuse, etc. for both industrial and municipal plants. In this paper, the performance of this system is demonstrated with the help of tests conducted at the Brookhaven National Laboratories. The process involved is such that in addition to emission reductions, heat is recovered that can be reused based on plant specific needs and requirements.

Presently, there are different systems available for specific emission reductions. For example, SCRs & SNCRs for NO_x reduction, dry and wet scrubbers for SO_2, HCL and dust removal, and baghouses and electrostatic precipitators (ESPs) for particulate removal. While these systems are effective in meeting their intended purpose, they have limitations in the range of their applicability. The method presented is a “one system does it all” with a simple process that is basically replicating nature's process in a controlled setting that is easy to operate and maintain.

Typically, the proposed system consists of patented ozone injection in the breeching of exhaust gas stream, allowing sufficient residence time for NO to NO_2 reaction to take place, injecting water mixed with 2% peroxide solution as a fogging stream to saturate hot gases and convert SO_2 to sulfuric acid mist that is condensed along with nitric and some carbonic acid over a set of condensing coils. This condensation process also removes over 99% particulate and heavy metals and approximately 10% CO_2 in addition to NO_x and SO_2 as described above. The wastewater collected at the bottom of the unit is then removed and treated to neutralize the acids and dispose of other pollutants.

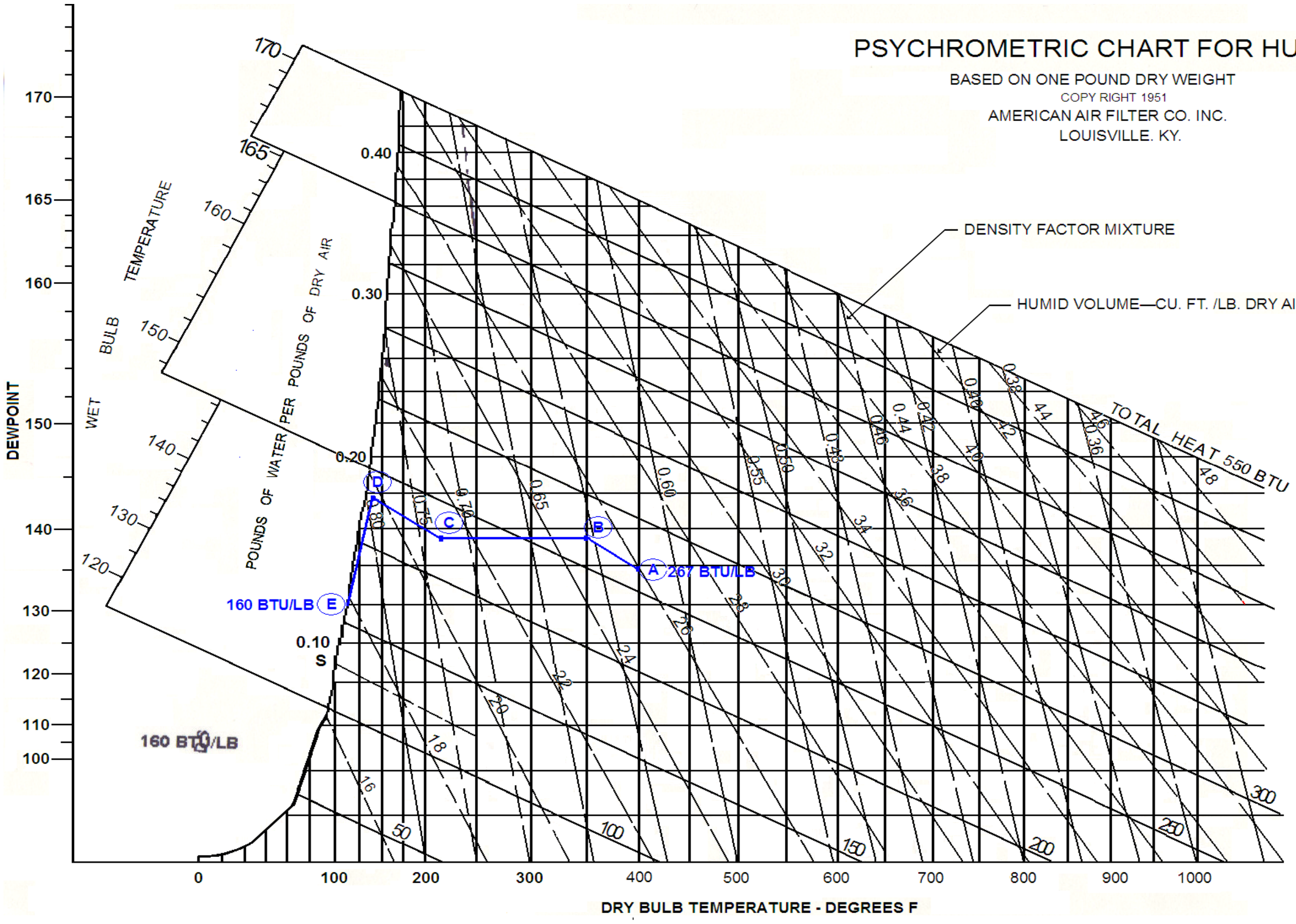

Figure 1: Process description with the help of psychometric chart.

While the proposed application to reduce emissions is recent, the system components like foggers, coils, fans, cooling towers, pumps, etc. are proven technologies that have been in use over decades. Yet several design challenges were encountered initially that took several years of R&D work to overcome and make the system practical for industrial and utility applications.

FUNDAMENTALS

To fully understand the methodology requires an appreciation of the fundamental principles of stoichiometric combustion wherein a fuel is burned in air at 100% efficiency.

For most commercial fuels excluding coal, approximately fifteen pounds of combustion air is required to burn one pound of natural gas (methane) or equivalent liquid fuel to produce sixteen pounds of flue gas hereafter referred to as POCs (products-of-combustion). The burning of methane produces approximately 1.02 kg (2.24 lb) of water as superheated steam. Liquid fuels produce substantially less moisture, about 0.64 kg (1.42 lb) of water per 0.45 kg (1 lb) of fuel depending on the hydrogen content of the fuel. In similar fashion the carbon content of the fuel produces primarily carbon dioxide. Carbon monoxide occurs through incomplete combustion and mainly from poorly controlled quantities of oxygen within the process. It is excessive CO accompanied by UHCs that result in cold, smoky flame.

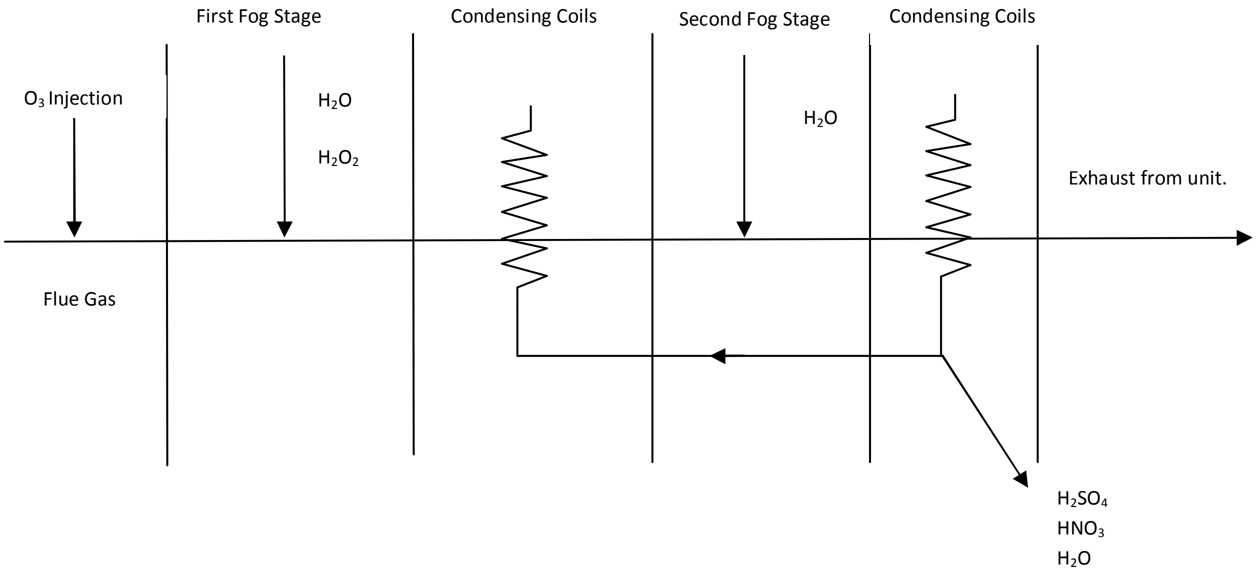

Figure 2: Schematic illustrating process in the unit with ozone injection for NO_x control and hydrogen peroxide spray for SO_2 control.

It is the burning of the hydrogen component of the fuel that contributes to the presence of moisture present in the POCs. This component is what gives rise to the wet bulb temperature measurable within the POC, as the amount of moisture introduced with the combustion air supply is trivial by comparison.

The heat in the POCs is utilized by most modern and efficient boilers to remove as much heat as necessary and economical through radiative and convective heat transfer surfaces resulting in exhaust temperatures near 149°C (300°F). Older, less efficient units may have temperatures significantly higher than these, thereby offering opportunities for additional heat recovery along with emission reductions.

Thermal NO_X emissions are about 150 ppm, although modern installations utilizing low-NO_X burners are capable of reducing the generation of these unwanted emissions to about 25 ppm for gas firing and 42 ppm for distillate fuel. The higher NO_X limit for distillate fuel firing is to allow for nitrogen content of the fuel that appears as NO_X.

Distillates also produce sulfur dioxide, SO_2, due to oxidation of sulfur present in the fuel. The sulfur content of the fuel can vary anywhere from ½ to 6% depending upon the grade of the fuel.

The POCs emerging from the boiler are classified into two categories - dry gas and moisture present as superheated steam. The term superheated steam refers to steam well above its saturation temperature because of its presence in essentially dry gas mixture at high temperatures. The dry gases have a specific heat value of about 1.05 kJ/kg-K (0.25 Btu/lb-°F) while the steam has a specific heat of about 2.01 kJ/kg-K (0.48 Btu/lb -°F) which makes increased moisture content a valuable additive in the heat transfer process from the POCs. As an example, a 75% /25% gas steam mixture has an aggregate and advantageous specific heat of 1.3 J kJ/kg-K (0.31 Btu/lb-°F).

The added benefit of condensing the wet component of POC is heat recovery from exhaust gases which otherwise is wasted to the atmosphere. As an example, 1.02 kg (2.24 wet lb) of POC per 0.45 kg (1 lb) of methane burned has potential of 2,109 kJ (2,000 Btu) for additional recovery at 60°C (140°F) condensing temperature. While 0.45 kg (1 lb) of methane releases 24,672 kJ (23,400 Btu) when burned, about 3,585 kJ (3,400 Btu) in superheated steam is often wasted.

This technology captures additional heat to essentially increase utilization of a natural gas fired system by an additional 10%. When applied to distillate fuel, about 1,265 kJ (1,200 Btu) of the 19,716 kJ (18,700 Btu) heat released per 0.45 kg (1 lb) of fuel can be recovered, increasing utilization of the fuel by over 6%.

The heat recovery process is shown with the help of a psychrometric chart in Figure 1. Although this chart is for air and water as vapor, little if any error, is introduced by applying it to respective dry and wet POC components. Point A shows the initial flue gas entry condition at 204°C (400°F) with a moisture content of 0.14 kg/kg (lb/lb) of dry air. Moisture is added by foggers to cool it to 177°C (350°F) at 15% humidity ratio, Point B. Note that the specific volume has decreased which greatly increases the heat transfer rate when cooled to Point B.

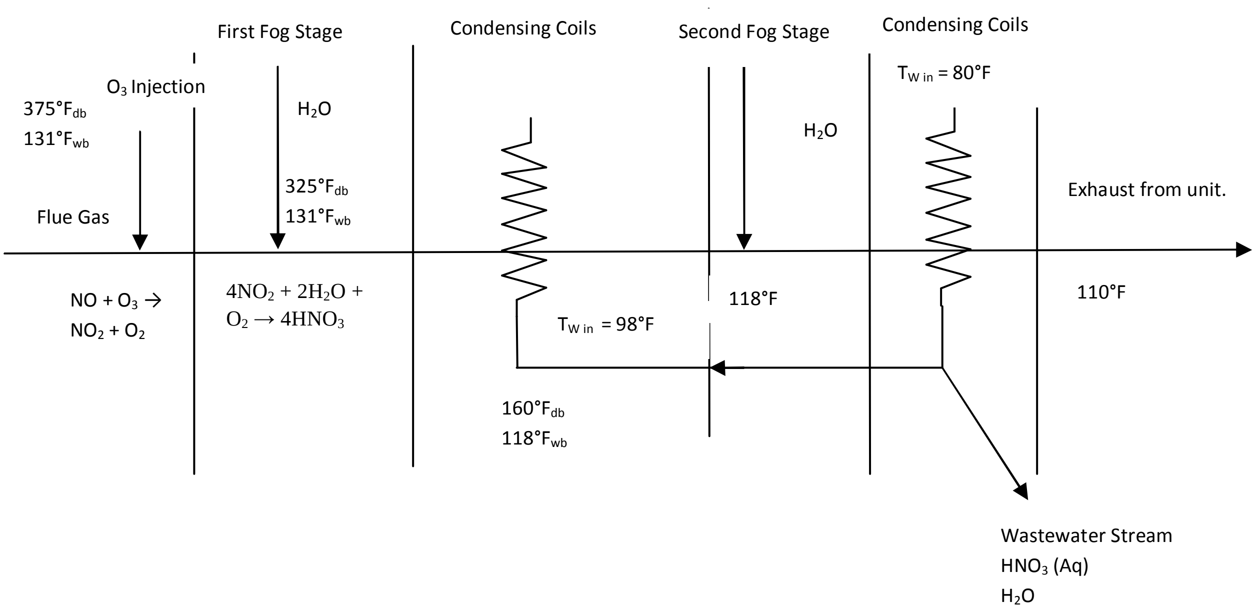

Figure 3: Schematic showing chemical reactions in the unit (ozone injection, no sulfur in fuel).

SYSTEM DESCRIPTION

The unit consists of an enclosure with first stage of fogging arrays followed by condensing coils and then a second stage with similar arrangement. If the objective is to remove NO_x, ozone is added as a reagent upstream of the unit typically in stack breeching through an aspirator at 1.1 stoichiometric concentration. The ozone oxidizes NO to NO_2 as shown in Eq. (1) which is water soluble.

$$NO + O_3 \rightarrow NO_2 + O_2 + \text{light} \qquad (1)$$

The seeded flue gas then enters the unit where it is uniformly sprayed by fogging arrays (see Fig. 2). The purpose of foggers is to uniformly mix ultrafine water droplets with large quantities of induced envelope gas flow to achieve an extremely turbulent and homogenous mixture of superheated steam to achieve a temperature range more suitable for a hydrolysis reaction whereby the gas stream effectively forms acid vapors. See Eq. (2).

$$4NO_2 + 2H_2O + O_2 \rightarrow 4HNO_3 \qquad (2)$$

For SO_2 removal, typically 2% hydrogen peroxide solution is added to water for first stage of fogging sprays at the inlet of the unit as described above. The reaction is as follows:

$$SO_2 + H_2O_2 \rightarrow H_2SO_4 \qquad (3)$$

All chemical reactions that occur within the unit can be readily found in most basic chemistry books.

Water along with hydrogen peroxide solution, if required, is sprayed into the exhaust gas stream entering the unit with the help of nozzles placed in arrays through the cross-section to ensure uniform distribution. The design is such that the entire flue gas stream is exposed to the fogger formed flow streams. In this manner, the widely dispersed 100 to 300 ppm of pollutants which require mitigation, are brought into intimate contact with the fog droplets through kinetic energy entrainment at the fog point of origin. The kinetic energy of the mix is a function of the kinetic energies of its respective components.

Further mixing on a molecular basis is both required and achieved by successful dispersion of unstable large surface area to weight ratio water droplets into hot flue gas. Each droplet, whose size is controlled by liquid pressure and nozzle configuration, requires only a small quantity of heat to vaporize. Vaporization causes the change of state from 0.001 m^3/kg (0.016 ft^3/lb) water to superheated steam having specific volume of about 6.24 m^3/kg (100 ft^3/lb), within the temperature ranges to which the technology is applied. Hence, the volumetric expansion ratio when liquid is flashed into steam is about 6,000:1 (100/0.016) which is an explosive dispersion of water vapor molecules provided that droplet size is tightly controlled for flash equilibrium at vaporization temperature. The technology provides the means to precisely control droplet size which allows the sequential dispersion rate to be expressed as the cross product of the sequential mixing effects, 400:1 times 6,000:1, or about 2.4×10^6. These rates are quite similar to the controlled explosion of fuel molecules in internal combustion engine cylinders.

The induction function assures that not only are the receiving gases well mixed, but the droplets are radically propelled away from each other at high velocities relative to the mainstream flue gas flow in a pattern shaped and controlled by the foggers. In this manner each droplet, upon absorption of its heat of vaporization, flashes into steam. Hence, the mixing process created by the application of high pressure foggers is a sequential one wherein the actual mix is the cross product of the foggers 400:1 mixing rate times the flash rate molecular dispersion of 6,000:1 resulting in a combined mixing rate which approaches 2,400,000:1 and within these sequential mixing zones are the collected POC reactive intermediates.

This dispersion mimics what happens in atmospheric dispersion of stack gases where the hydrolysis reaction of water molecules is known to transform NO into NO_2 and upon sufficient molecular contact with water molecules bond to form nitric acid, HNO_3, in its vapor state. To force the acid gas formation reaction, a near to saturation state is required, which is what the Point C to Point D fogging process assures (see Fig. 1) by providing an abundance of available water molecules so well dispersed as to assure molecular collisions with the reactive NO_X molecules. Point D is designed for a fogging capacity to assure that 15 to 20% (150 to 200,000 ppm) of molecular moisture, as superheated steam, is available to assure adequate contact with all of the 100 to 300 ppm of unstable gas stream NO_X content and in the case of liquid fuel the 5,000 ppm or greater of SO_2 common to the boiler-burner-furnace combustion equipment to which the technology is applicable.

These multipliers of stoichiometric reaction rates are required to offset the slow time constants which govern acid formation within ambient air, sequential dispersion which entails cooling, hydrolysis and condensation process within which acid rain wet deposition conditions occur. As pollutant bearing flue gases disperse into the atmosphere to cool to temperatures near 32°F, even the very small percentage of available moisture is adequate to nearly saturate the air which permits the acidification of reactive POC components.

To enable these reactions to be controlled within a fixed geometry requires a very high moisture concentration and simultaneously lowering of temperature along with the means to condense the gases and entrap the acids within sufficient condensed water quantity to preclude re-evaporation by further cooling the condensate film to well below the boiling point temperature of the liquid phase of the acid gases.

Gaseous phase nitric and sulfuric acid molecules are highly soluble and upon contacting the wet coil film during the gas flow condensation process readily enter solution within the liquid surface of the condensing film to form dilute acids in solution. The condensate over the coils flow to the drain pans mounted at the bottom of the coils by gravity. This condensate is then removed from the drain pans by a condensate collection system. The acidic wastewater including other particulates condensed from the gases along with any heavy metals can then be treated with suitable wastewater treatment.

The system is designed to capture all the pollutants with minimum condensate. This is an important feature of the technology as the contaminated condensate must be subsequently processed as industrial waste to be treated for pH neutralization, clarification for precipitation and treatment by dewatering apparatus for disposal.

Figure 4: Unit used for performance testing.

Another potential advantage of using condensation process as described above is utilization of heat absorbed by circulating fluid within the coils to preheat combustion air or fuel, building heating or in an absorption system to provide cooling during winter or some other useful purpose that would improve plant efficiency. Any remaining heat can then be either rejected to the atmosphere through cooling tower or used to reheat exhaust gases downstream of the condensing coils before discharge to the atmosphere. In this case, reheat coils are placed downstream of the second stage of coils.

PERFORMANCE TEST

The system described in this paper was tested in Brookhaven National Laboratory to verify its performance and effectiveness in reducing emission levels in the exhaust gas stream of boilers targeted under the Federal Clean Air Act. Figures 3 and 4 show schematic and photo of the test unit.
Prior to the start of this test program, an extensive set of exploratory tests were conducted at Brookhaven National Laboratory (BNL). These served to identify the conditions under which high NO_X and SO_2 levels could be achieved. Figure 5 shows one example of some of this preliminary work in which NO_X removal has been evaluated as a function of ozone to NO_X ratio.

DESCRIPTION OF THE TEST SITE

The test site consisted of temporary boiler installation at Brookhaven National Laboratory. All major equipment was installed outdoors, in close proximity to a commercial boiler/economizer test laboratory. A schematic of the test arrangement is included in Figure 6.

Boiler - The boiler was manufactured by EMO-Energetika Ltd. Sentjur, Slovenia; Model W2-450 with a nominal capacity rating of 450KW. It was a horizontal, return flow, firetube design. This low-NO_x boiler had extended heat transfer surface to reduce peak flame temperatures. Some of the hot water from the boiler was dumped to the drain and some returned to a mixing tank where it was combined with cold feed water. In steady state the fraction of the hot water dumped and the cold water feed was manually adjusted. Thermocouples were installed to measure the boiler supply and return water temperatures.

Burner - The burner was a conventional, pressure atomized, two stage unit designed for distillate oil. It was manufactured by R.W. Beckett Corp. Model CF2300A.

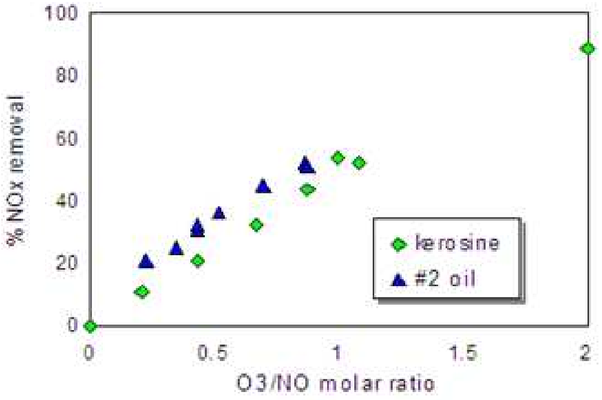

Figure 5: Example of results of preliminary testing showing % NOx removal as a function of ozone to NOx molar ratio.

Test Unit - All of the flue gas from the boiler was directed to the unit through a nominal 8" diameter, uninsulated duct. The control system and variable speed fan on the unit maintained a constant draft level at the boiler exit and performed well during the test program.

Cooling water to the heat exchangers was provided from a common cold water supply line. The water from the heat exchangers was sent to a drain during this test program. At periodic intervals, the mass flow of cooling water was measured by collecting the discharge over a time period.

Ozone Injection Spool - An ozone injection spool was installed in the connecting duct at the boiler exit. This 36" long section includes an arrangement of injection pipes and a static mixing section. Here a mixture of ozone and oxygen was injected into the combustion products.

At the exit of the unit, 100% of the combustion products were exhausted through a short rectangular galvanized steel stack. A polypropylene woven fiber mesh pad was installed to minimize droplet carry over. Condensate from the flue gas and spray water was collected at the bottom of the unit with samples taken during the test program for later analysis. Samples of combustion products were taken for gaseous analysis both at the boiler exit upstream of the ozone injection point and at the exit of the unit.

Ozone for this test program was produced by a high voltage ozone generator manufactured by PCI Ozone and Control Systems, Inc., Model G-7. With air, this unit had a maximum rated output of 3.2 kg (7 lb) of ozone per day. With oxygen, capacity increased to 8.2 kg (18 lb) per day. For both tests included here in which ozone was used, the generator was operated with oxygen at an output setting of 60% of maximum capacity.

For tests in which a solution of hydrogen peroxide was added to water for injection at the foggers, the solution was prepared in an open-top plastic drum and pumped to the foggers.

TEST PLAN

Three specific tests were planned and completed as follows:

1. NO_X Removal - The objective of this test was to demonstrate the capability of the unit as a NO_X capture device only. The test fuel in this case was kerosene, selected as an example of low sulfur content fuel. The rationale was minimization of any possible interference between sulfur dioxide and NO_X capture in the unit. In this test, ozone was injected into the flue gas at the boiler exit at a relatively high rate to ensure conversion of NO_X to nitric acid. Measurements included flue gas oxygen, CO and NO_X at the unit inlet and outlet. Also measured was flue gas ozone concentration at the unit outlet.

2. SO_2 Removal - The objective of this test was to demonstrate the capability of the unit as a SO_2 capture device only. The test fuel in this case was No. 2 distillate fuel oil. The sulfur content of this delivered fuel was reported to be 0.2%. Tertbutyl disulfide was added to this fuel to increase the sulfur content to about 0.3%. A 2% solution of hydrogen peroxide was injected at the fogger nozzles. Flue gas measurements included oxygen, NO_X and SO_2. In addition, particulate sampling trains were run at the unit inlet and outlet simultaneously. These trains are described further in the next section.

3. Combined NO_X/SO_2 Removal - The final test was conducted to evaluate performance of the unit for removing both SO_2 and NO_X simultaneously. The ozone injection conditions at Test 1 were combined with the hydrogen peroxide spray of Test 2. No. 2 distillate fuel oil with 0.3% sulfur was fired. Flue gas measurements included oxygen, NO_X, and SO_2.

MEASUREMENT METHODS

FLUE GAS ANALYSIS - Gas was delivered to rack-mounted flue gas analyzers using a refrigeration drier/gas sampling system. The system suction side was tested for leakage on a regular basis. In addition, calibration gases were periodically sent through the entire sampling system to evaluate possible interference.

Flue gas oxygen content was measured using a Rosemont Model 755 paramagnetic analyzer. Typically, measurements were made using a 0-10% oxygen scale. The analyzer was calibrated before, during, and after test runs using nitrogen (zero gas) and 9.0% oxygen in nitrogen calibration gas.

Flue gas NO_X was measured using a Rosemont/Beckman, Model 951 Chemiluminescent analyzer. Ranges used were 0-100 ppm and 0-250 ppm. The analyzer was calibrated using nitrogen and 100 ppm NO in nitrogen.

Flue gas SO_2 was measured using an ENERAC Model 200 analyzer manufactured by Energy Efficiency Systems, which incorporated an electrochemical cell sensor. This analyzer had a nominal resolution of l ppm and accuracy of 2% of the reading. During test #2, confirmation of SO_2 removal was provided through analysis of particulate train ice bath impingers #2 and #3.

During the test program, two other analyzers were available for SO_2 measurements and were used for confirmation of some tests. Some difficulties arose with these that are worth noting. Prior to the start of these test series some exploratory work was done during which the hydrogen peroxide solution was sprayed in the fogger nozzle and flue gas was sampled from the unit exhaust. Following this sampling system checks indicated very high absorption of SO_2 within the conditioning hardware. The expected cause was un-reacted peroxide within the drier. For SO_2 measurements a parallel sampling system was installed with an easily cleanable cold trap. This new system had a low sampling rate and very slow system response and therefore was not used during the final test runs.

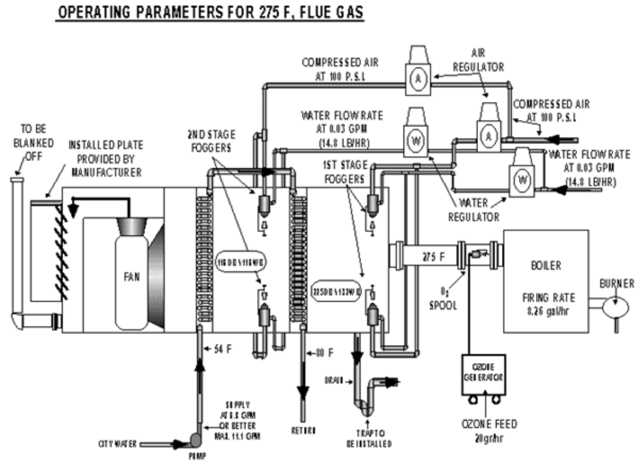

Figure 6: Schematic of test arrangement.

Flue gas ozone was measured by a wet sampling method. A measured volume of gas was bubbled through a 2% solution of KI in deionized water. A calibrated dry test meter was used to determine gas volume and sampling time was normally five (5) minutes. Average sampling rate was 0.7 scfm. The absorber solution was then transferred to a beaker, acidified and titrated with sodium thiosulfate.

The particulate sampling train was operated as a combination of U.S. EPA methods 5 and 8. The filter was maintained at 121°C (250^{o}F). Impinger #1 in the ice bath contained 100 ml of 80% isopropanol in deionized, distilled water. The second and third impingers both contained 100 ml of 3 percent hydrogen peroxide. Approximately 200g of silica gel was placed in the fourth impinger.

At the unit inlet, particulate sampling was done in 202 mm (8”) diameter x 3,048 mm (120”) long duct connecting the ozone injection spool with the unit. The sampling point was 1,981 mm (78”) downstream of the injection spool (L/D=9.75) and 1,067 mm (42”) upstream from the unit (L/D=5.25). A single sampling point was used at the duct center.

At the unit outlet particulate sampling was done in a vertical rectangular duct, 260 mm x 470 mm (10.25” x 18.5”). The sampling location was 674 mm (26.5”) downstream of the mesh pad mist eliminator and 572 mm (22.5”) upstream of the duct exit opening. At this location nine points were included in the sampling traverse.

The flow rate of oxygen through the ozone generator was determined using rotameter integral with the PCI ozone generator and pressure correction factors provided by that manufacturer. The rate of injection of ozone was estimated based only on manufacturer's specifications.

The actual firing rate of the burner was measured for each of the two test fuels in advance by feeding the fuel to the burner from a fuel supply on a weigh scale. The actual rate of injection of water or peroxide solution at the foggers was determined after the performance tests by reproducing the fogger conditions with water only and carefully measuring the water feed rate volumetrically.

RESULTS

Results of the three tests done are summarized in Table 1. Test #1 basically serves to show that the unit can achieve high levels of NO_X removal. In this case the ozone injection rate was high. Based on earlier exploratory tests, it is likely that similar NO_X removal levels could be achieved with lower O_3/NO_X ratios. The ozone level in the flue gas at the unit outlet was measured to be 51 PPM. The manufacturer has plans to eliminate this slip in the future.

Following Test #1 some problems occurred with plugging of the fogger nozzles by contaminants in the feed system. This problem was solved primarily through addition of a filter in the fogger inlet line. As part of solving this operational problem the foggers were changed to increase the size of the internal orifices. This led to the great increase in fogger water flow shown in Tests 2 and 3. In these tests the fogger flows and the peroxide/SO_2 ratios were higher than planned by the manufacturer for commercial operation.

Test #2 serves to demonstrate that the unit can achieve high levels of SO_2 removal. SO_2 measurements made by the electrochemical cell analyzer and analysis of particulate sampling train impingers were nearly in agreement. The apparent increase in particulate emissions across the unit is an interesting test result, although both inlet and outlet particulates were extremely low. A possible source of particulates was corrosion products from the unit internals. This unit had been subjected to extensive exploratory tests prior to this test program and some corrosion of the exhaust fan was observed. An alternative possibility is the collection of high amounts of acid aerosol and peroxide solution aerosol on the filter. In initial tests some problems with rapidly increasing pressure drop across the filter were observed. It was suggested that the filter may have been plugged with water droplets and by increasing the filter temperature to about 135°C (275^{o}F) for a short time, this problem was eliminated. Sampling continued without difficulty after reducing the filter temperature to an average of 121°C (250^{o}F).

Results of Test #3 showed that the unit can simultaneously remove both NO_x and SO_2.

CONCLUSIONS

The effectiveness of proposed system in simultaneous removal of major pollutants present in the exhaust gas stream of boilers was successfully demonstrated with the help of a series of tests conducted at the Brookhaven National Laboratory. Currently a facility is being built in Louisville, Kentucky for demonstration to clients and further improvement in results. In summary, performance of this system combines the performance of several commercially available individual systems that are targeted towards removing specific emissions such as NO_x, SO_2 and particulate. As an added benefit, there is opportunity for heat recovery that would otherwise be discharged to the atmosphere and wasted. These units are commercially available to meet site specific needs and they can either be shop assembled to facilitate installation or field-erected for large boilers depending upon client's preference and needs. There is basically no size restriction on the boilers to which this technology can be suitably applied.

Table 1 – Summary of test results.

		Test 1. NO_x Removal	Test 2. SO_2 Removal	Test 3. NO_x & SO_2 Removal
Fuel fired	-	Kerosene	No.2 fuel oil	No.2 fuel oil
Firing rate	l/hr (gal\hr)	28.3 (7.47)	31.3 (8.27)	31.3 (8.27)
Temperatures:				
Boiler water out	°C (°F)	66.7 (152)	66.7 (152)	60 (140)
Unit, water temp. in	°C (°F)	18.3 (65)	13.9 (57)	13.9 (57)
Unit, water temp, mid	°C (°F)	27.2 (81)	25.6 (78)	26.1 (79)
Unit water temp, out	°C (°F)	41.7 (107)	38.9 (102)	35.6 (96)
Flue gas at boiler exit	°C (°F)	212.2 (414)	215.6 (420)	211.7 (413)
Gas at 1st heat exchanger face	°C (°F)	150.6 (303)	87.8 (190)	-
Gas leaving Unit	°C (°F)	46.1 (115)		
First fogger air	bars (psig)	6.4 (93)	5.3 (77)	4.8 (69)
First fogger water	bars (psig)	5.0 (72)	4.4 (64)	5.0 (72)
Second fogger air	bars (psig)	6.5 (94)	5.2 (75)	4.8 (70)
Second fogger water	bars (psig)	4.9 (71)	4.1 (59)	4.6 (67)
O_2 Boiler exit	%	8.2	7	6.8
O_2 Unit exit	%	11.3	8.2	9.1

NO_x Boiler exit	ppm	46	58	51
NO_x Unit exit	ppm	2	51	1
SO_2 Boiler exit	ppm	-	77	75
SO_2 Unit exit	ppm	-	2.5	6.7
CO Boiler exit	ppm	20	8	10
CO Unit exit	ppm	20	6	10
NO_x Boiler exit	ppm@3%O_2	64.5	72.8	64.8
NO_x Boiler exit	ppm@3%O_2	64.5	72.8	64.8
NO_x Unit exit	ppm@3%O_2	3.9	71.7	1
NO_x Removal	%	94	1.4	98.6
SO_2 Boiler exit	ppm@3%O_2	-	96.6	95.6
SO_2 Unit exit	ppm@3%O_2	-	3.5	15.2
SO_2 Removal	%	-	96.4	89.4
Ozone injection rate	kg/hr (lb/hr)	0.2 (0.45)	-	0.2 (0.45)
Ozone generator oxygen flow	kg/hr (lb/hr)	7.7 (17)	-	7.7 (17)
Water injection rate (in foggers)	kg/hr (lb/hr)	45.3 (100)	-	
Peroxide solution injection rate (in foggers)	kg/hr (lb/hr)	-	136 (300)	136 (300)
O_3/NO_x molar ratio	-	5.1	-	4.5
H_2O_2/SO_2 molar ratio	-	-	55	57
COMPLY 2000 heat exchangers water flow rate	kg/hr (lb/hr)	453 (1,000)	513.7 (1,133)	482.5 (1,064)
Particulates at boiler exit	kg/KJ (lb/MMBtu)	-	0	-
Particulates at Unit exit	kg/KJ (lb/MMBtu)	-	0.017 (0.04)	-
Unit heat exchanger heat recovery	KW (Btu/hr)	12.3 (42,000)	14.9 (50,985)	12.2 (41,496)
Unit heat exchanger heat recovery	% of boiler input	4.1	4.4	3.6
SO_2 at boiler exit based on particulates train impinger analysis	ppm	-	70	-
SO_2 at Unit exit based on particulates train impinger analysis	ppm	-	1	-
SO_2 removal efficiency based on particulates train impinger analysis	%	-	98.4	-