ON-LINE LASER MEASUREMENT OF COAL PROPERTIES DEMONSTRATED AT POWER PLANT

Coal-fired power plants, which experience frequent changes in coal quality due to inherent variations in coal composition, switching of coal suppliers and/or coal blending, are subject to unexpected changes in coal higher heating value, moisture, ash content and amounts of specific elements in the coal such as sulfur. This can lead to operational difficulties due to factors such as changes in furnace and convective pass slagging/fouling patterns and changes in emissions. Carlos Romero of Lehigh’s Energy Research Center and Robert De Saro from the Energy Research Company of Staten Island, New York, have been leading a research effort to develop a laser spectroscopy approach for on-line coal analysis. Their joint University-Industry team has just completed the successful deployment and testing of a commercial on-line coal property measurement system at PPL’s Montour Power Station.

Romero explains, “We are using a measurement technology referred to as Laser Induced Breakdown Spectroscopy (LIBS) along with artificial intelligence techniques to determine the composition of the coal ash and relate the composition measurements to parameters such as ash slagging potential and higher heating value. The LIBS System consists of a pulsating laser, optical spectrometer, supporting optics and a signal processing computer. The laser vaporizes a small sample of the coal and the resulting plasma is analyzed to determine the composition of the coal ash.”

USING HEAT EXCHANGERS TO CAPTURE MOISTURE FROM FLUE GAS AND IMPROVE UNIT HEAT RATE

With increasing competition for water from farms, manufacturing facilities and cities and towns, some coal-fired power plants are finding it increasingly difficult to obtain the large flow rates of water needed for power plant cooling. At the same time, with rising fuel costs and concerns for global warming, there is renewed emphasis on improving power plant heat rate and this has led to interest in technologies which result in increased power plant efficiency. With these factors in mind, researchers from the Energy Research Center (ERC) have just completed a DOE and industry-funded project dealing with the use of heat exchangers to cool boiler flue gas, capture moisture from the flue gas, and use heat from the flue gas to improve unit heat rate. The project was led by Drs. Edward Levy, Harun Bilirgen and John DuPont.

Levy explains, “The moisture content of boiler flue gas ranges from approximately 6 to 17 volume percent, depending on the type of coal and whether or not the unit has a wet SO2 scrubber (FGD). The corresponding values for water vapor dewpoint temperature range from approximately 100 to 135°F. Most of the water consumed in a power plant with an evaporative cooling tower is used for cooling tower makeup water. Coal-fired power plants, equipped with a means of extracting all the flue gas moisture and using it for cooling tower makeup, would be able to supply from 10 percent to 33 percent of the cooling tower water needs by this approach.”

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- Using Heat Exchangers to Capture Moisture from Flue Gas and Improve Unit Heat Rate
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portion of the coal sample, and the resulting measured emission spectrum provides an indication of the relative intensities and wavelengths of the elements which were present in the coal sample. The measured wavelengths and their intensities are then used to identify the elements and their relative concentrations. The following elements can be measured with the type of spectrometer used in the system: Al, C, Ca, K, Mg, Na, Fe, S, Si, and Ti.

The LIBS measurements, which are made on the coal belt, are extremely fast, with data from a coal sample collected in a matter of seconds. However, a much larger number of data points are typically collected to improve the accuracy of each measurement. The measurement system is supported by computer software which allows real-time display of coal properties and provides expert advice to boiler operators for coordination of coal yard operation and modification of boiler operating conditions for efficient fuel combustion and mitigation of slagging and fouling.

Although the project team had demonstrated the ability to use the LIBS technique to measure coal properties at a power plant in 2008 (see Lehigh Energy Update, Vol. 26, No. 2, July 2008), the coal was sampled manually and the LIBS measurements and the artificial intelligence analyses of the LIBS data were made off-line. The recent demonstration at Montour Station involved a fully automated deployment of a full-scale, calibrated LIBS instrument and supporting software, where the coal measurements were made on one of the coal transfer conveyor belts between the coal crusher and the coal bunkers. PPL’s Montour Station is located in Washingtonville, Pennsylvania. The plant, which has two 775 MW coal-fired units, fires bituminous coals which arrive via rail trains from a range of suppliers. An important problem with the plant feedstock is fuel variability and delay in obtaining fuel analysis from the on-site laboratory, especially when up to 50 percent of the unloaded coal goes directly to the boilers. Montour faces the increasingly difficult job of maximizing unit generation, while accessing a large number of suppliers to offset the increasing cost of fuel, and maintaining good unit availability by mitigating the undesirable impacts of fuel quality on unit operation.

Evaluation of the LIBS System at Montour Station took place from January to March 2011. Seventy-three hours of run time were conducted with the LIBS System in service to evaluate measurement accuracy and repeatability of the analyzer and associated software in determining iron and sulfur content, coal heating value, and initial deformation ash fusion temperature. Iron is of interest since elevated concentrations of this element promote reductions in minimal ash fusibility temperatures. Sulfur is of interest since the power plant FGD scrubbers require sulfur content for optimal cost-effective operation.

Validation tests were performed with the six bituminous coals most commonly fired at Montour to evaluate the accuracy of the on-line coal analyzer, as well as to identify limitations of the system under dynamic conditions. The validation tests consisted of grabbing reference coal samples using a conventional method, followed by ASTM laboratory analysis and then comparing the laboratory results with data collected and analyzed by the LIBS system. A statistical analysis performed on the data and the results, expressed in terms of the root mean squared difference (RMSD) between the reference and analyzer values, shows close agreement. (see Table). De Saro adds, “With funding from DOE, the Energy Research Company and the Energy Research Center will be conducting a full-scale on-line demonstration of LIBS technology in 2012 at Dayton Power & Light’s Stuart Station.

<table>
<thead>
<tr>
<th>Sample</th>
<th>IDT (°F)</th>
<th>LIBS Results-1</th>
<th>LIBS Results-2</th>
<th>Lab Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal A</td>
<td>1/29</td>
<td>2200</td>
<td>2300</td>
<td>2300</td>
</tr>
<tr>
<td>Coal B</td>
<td>1/31</td>
<td>2200</td>
<td>2300</td>
<td>2300</td>
</tr>
<tr>
<td>Coal C</td>
<td>1/35</td>
<td>2200</td>
<td>2300</td>
<td>2300</td>
</tr>
</tbody>
</table>

On-Line LIBS Data and Laboratory Results for Ash Fusion Temperature. Spread in Laboratory Results Reflects Uncertainty in ASTM Values of Fusion Temperature.

LIBS Measurement Accuracy

<table>
<thead>
<tr>
<th>Element</th>
<th>Accuracy</th>
<th>RMSD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Iron (%)</td>
<td>1.07</td>
<td></td>
</tr>
<tr>
<td>Sulfur (%)</td>
<td>0.14</td>
<td></td>
</tr>
<tr>
<td>Fusion Temp. (°F)</td>
<td>33.16</td>
<td></td>
</tr>
<tr>
<td>Heating Value (Btu/lb)</td>
<td>75.86</td>
<td></td>
</tr>
</tbody>
</table>

This application will evaluate the capabilities of LIBS to confirm the specifications of the incoming coal and to help achieve cost efficient blending of low quality Illinois and Central Appalachia coals. Other LIBS applications currently underway include the use of LIBS for biomass characterization (funded by the New York State Energy Research and Development Authority) and demonstration of the capabilities of LIBS to measure slagging temperature from coal elemental composition measurements for gasification applications (funded by the Electric Power Research Institute).

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Using Heat Exchangers

would be in the 125 to 135° F range. While if installed downstream of a wet FGD, the flue gas inlet temperature would be in the 125 to 135° F range. Cold boiler feedwater is one possible coolant for the heat exchanger, with flue gas flowing around the heat exchanger tubes and boiler feedwater flowing inside the tubes.

Use of heat exchangers in the back end of the boiler to recover water vapor from flue gas also provides opportunities to improve unit heat rate. With boiler feedwater as the coolant, sensible and latent heat transferred from flue gas will preheat the feedwater, thus reducing the steam turbine LP extraction flows to the low temperature feedwater heaters and thereby reducing unit heat rate. Results of turbine cycle analyses made by the project team show predicted reductions in heat rate ranging from 0.45 to 1.9 percent. Improvement in heat rate at a given site will depend on inlet flue gas temperature and moisture content, flue gas exit temperature and feedwater inlet temperature.

Bilirgen adds, “Our condensing heat exchangers are intended for use downstream of an ESP or baghouse. For a unit without a wet FGD, the heat exchanger would operate with a flue gas inlet temperature of approximately 300° F, while if installed downstream of a wet FGD, the flue gas inlet temperature would be in the 125 to 135° F range. Cold boiler feedwater is one possible coolant for the heat exchanger, with flue gas flowing around the heat exchanger tubes and boiler feedwater flowing inside the tubes.”

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Levy continues, “The project involved slip stream tests of a small-scale heat exchanger system at three coal-fired units, laboratory corrosion studies of candidate tube materials, evaluation of condensate treatment options and costs, designs of commercial scale heat exchangers and cost/benefit studies of condensing heat exchangers.”

“The slip stream field tests resulted in important insights on the effects of heat exchanger design and process conditions on heat transfer and water vapor condensation rates. The resulting field test data also made it possible to validate computer software developed by the project team for predicting the effects of heat exchanger design and operating conditions on rates of heat and mass transfer from flue gas. The software was then used to design full-scale heat exchangers for use in coal-fired power plants.”

The field tests were performed at two units without scrubbers and one with a wet FGD, where the unscrubbed units were firing low-sulfur high-moisture coals and the scrubbed unit was firing a high-sulfur bituminous coal. In all cases, the flue gas contained gaseous species such as SO₂, H₂SO₄, and HCl, some of which wound up in the condensed water which formed on the heat exchanger tubes. The condensate was collected and analyzed for contaminants, and this resulted in data on sulfate and chloride concentrations in the condensed water.

DuPont adds, “The field test results were used to specify condensate acid concentrations for the laboratory corrosion studies, which, in turn, identified tube materials which would provide adequate service life for heat exchangers operating at the temperatures and acid concentrations expected with condensing heat exchangers. Based on results from our corrosion studies, we recommend that 304 stainless steel be used for tube material for locations where the tube wall temperature is less than the local water vapor dew point temperature. We also recommend that Alloy 22, a high nickel alloy with excellent resistance to sulfuric acid corrosion, be used in locations where tube temperatures are greater than the local water vapor dewpoint temperature and less than the local sulfuric acid dew point temperature.” (Note: Sulfuric acid dew point temperatures range from approximately 320° F to 250° F for the acid concentrations found in boiler flue gas. Water vapor dewpoints range from approximately 135° F to less than 110° F.)

The cost/benefit studies considered installed heat exchanger cost, condensate water treatment costs, and the costs of fan power to overcome flue gas pressure drop and pump power to overcome cooling water pressure drop. The benefits considered in the analysis included the incremental generated power resulting from using captured heat to preheat boiler feedwater and the value of the recovered water. Using this approach, the analyses concluded that for water recovery applications, condensing heat exchangers installed at units with wet FGD’s would produce the largest flow rates of condensed water and would be the most cost effective to install and operate. Because of higher flue gas inlet temperatures, condensing heat exchangers used in units without scrubbers would result in larger heat rate improvements and incremental increases in power. However, the higher inlet flue gas temperature would make it necessary to use more expensive tube material than is needed downstream of a wet FGD. The research is continuing to develop designs for maximizing percentage water capture and heat rate improvement and minimizing the costs of the heat exchangers.

There are also potential applications of condensing heat exchangers in carbon capture and sequestration systems (CCS).

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Amine and ammonia post-combustion CO₂ scrubbers require inlet flue gas temperatures below 100°F for efficient operation, and the types of heat exchangers described by the Lehigh team are candidates for use in pretreating boiler flue gas before it flows into a CO₂ scrubber. In addition, it is expected that, in most cases, the concentrated streams of CO₂ produced by post-combustion CO₂ scrubber systems and by oxyfuel boilers will be compressed to over 2,000 psia before being transported by pipeline to geologic sequestration sites. These concentrated streams of CO₂ can contain high concentrations of water vapor which should be separated from the CO₂ before compression and here, too, condensing heat exchangers may have an important role to play.

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