Using Automation to Improve Plant Heat Rate
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Heat rate is a key metric for power plants and helps determine profitability. By understanding where improvements can be made there are incremental opportunities for savings. This white paper explains the concept of heat rate and shows how savings can be realized and processes optimized through automation.

What is heat rate?

To measure the efficiency of a power plant, the term heat rate is commonly used. Heat rate is the measure of energy put into a system, commonly measured in Btu/kWh, divided by electricity generated, measured in kW.

\[
\text{Heat rate (Btu/kWh) = Input energy (Btu/hr) / Output power (kW)}
\]

The plant’s heat rate is calculated from the combined performance of all auxiliaries in the plant. The input energy is the chemical energy in the fuel and the power generated is the gross or net generation in kW. Heating value is the amount of heat that is released during the combustion of a specified amount of fuel. The higher heating value, or higher calorific value, is determined by the fuel’s original pre-combustion temperature when the water is in a liquid state, and is a quantity that is used when latent heat or vaporization of water is present. Lower heating value is calculated when the water is in its vapor state, by removing the heat of vaporization of water from the higher heating value. By doing this the energy needed to vaporize the water is not released as heat. The higher heating value is used when calculating gross energy for a plant. The lower heating value is used for net unit calculations.

Chemical Energy of Fuel = Total Fuel Used (scf/hr) x Higher Heating Value (BTU/scf)

By combining this with the previous formula, the following can be constructed to understand the net unit heat rate:

\[
\text{Net Unit Heat Rate (Btu/kWh) = Total Fuel Used by Unit (scf/hr) x Lower Heating Value (Btu/scf) / Net Output Power (kW)}
\]

The amount of input energy (fuel), which is turned into thermal energy (heat) driving the plant, will in the end determine plant efficiency and profitability. Improving fuel usage and optimizing the system will reduce heat rate and eventually lead to a more profitable operation.
Why is heat rate important?

For power plants, fuel cost reductions and increased availability are key improvement areas for cost containment. For some plants, fuel expenditure constitutes a large part of the total operating budget. Even a 1% improvement in heat rate impacts plant profitability.

By improving heat rate the plant reduces emissions, and by doing so will have a lower operating cost for air quality control systems. Better heat rate also implies lower CO₂ emissions.

Cost of a higher heat rate

Most plants have a design heat rate based on when the plant was built. The difference between the actual heat rate and this designed target is the deviation. These deviations are often small but represent real opportunities for improvement.

Heat rate example

In order to understand the financial impact of this, the formula below helps to translate changes in heat rate into its impact on annual fuel costs.

\[
\text{HRD/BE} \times \text{FC} \times \text{CF} \times \text{UGC} \times \text{T} = \text{change in annual fuel cost (}\$/\text{year})
\]

<table>
<thead>
<tr>
<th>Table 1. Heat Rate Glossary</th>
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<tbody>
<tr>
<td>HRD</td>
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<tr>
<td>BE</td>
</tr>
<tr>
<td>FC</td>
</tr>
<tr>
<td>CF</td>
</tr>
<tr>
<td>UGC</td>
</tr>
<tr>
<td>T</td>
</tr>
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</table>

A typical power plant may have a boiler efficiency of 85%, fuel costs at $2 per million Btu, and a plant capacity factor at 80%. Given these circumstances, a 500-MW coal-fired power plant operating for the full year could reduce fuel cost by at least $8,000/year for each unit (Btu/kWh) of heat rate reduction.

\[
\frac{1}{0.85} \times \frac{2}{1,000,000} \times 0.80 \times 500,000 \times 24 \times 365 = 8,245 \text{ /year}
\]

This formula will be used later in the paper to show how more substantial savings can be made.
Feedwater heater application

For power plants, small investments can often improve unit heat rate and provide cost savings. The feedwater heater is an area where such investments often repay themselves quickly.

The objective for the feedwater heater is to pre-heat water that will be delivered to a boiler. This improves the thermodynamic efficiency of the plant and results in a reduction in fuel.

Within a power plant there may be many feedwater heaters in a system. Each will have different temperatures and pressures and will take energy from different stages of the turbine. The feedwater heaters are often classified as low, intermediate or high pressure.

The feedwater heating process goes through three stages. The first step is the desuperheating zone. Superheated steam is cooled and becomes saturated steam. It then goes through the condensing zones, where energy is extracted from the steam/water and used to preheat feedwater inside a tube that is on its way to the boiler. The last step is a drain cooler which captures additional energy from the water. These three steps take place in any standard high pressure heater. In low pressure heaters the first step is often eliminated.

Figure 1. Horizontal Feedwater Heater

There are three variables that should be monitored when determining the performance of a feedwater heater. The first is the Terminal Temperature Difference (TTD). This measure assesses how close the outlet feedwater temperature is to the feedwater saturation temperature, or in other words, the capability of heat transfer in the feedwater heater. The objective is to achieve a
feedwater temperature as close to the steam inlet temperature as possible because the higher the TTD the poorer the performance of the feedwater heater. A feedwater heater is designed with a target TTD that often is around 5 °F (3 °C).

The next variable to be monitored is the Drain Cooler Approach (DCA) temperature, which is a measure of how close the heater drain outlet temperature is to the feedwater inlet temperature. A lower DCA temperature is better than higher, but the feedwater heater is designed with a target DCA temperature for optimal performance. If the DCA temperature is too high, it can lead to damaged tubes, as well as drain cooling zone end plates and baffles. Destructive velocities and rapid erosion in the drain cooling zone are probable outcomes of running the DCA temperature too high.

The last variable to be monitored is the feedwater Temperature Rise (TR). The difference between the feedwater outlet and the feedwater inlet is measured and the goal is to hit the specified target.

For a 500 MV plant a 1°C increase in a heater’s TTD can mean as much as a 0.033% increase in heat rate, which represents a substantial increase in fuel cost. A 1°C increase in DCA drives a 0.01% increase in heat rate. To monitor the TTD and DCA temperatures is therefore important since non-optimal TTD and DCA will increase heat rate and reduce electrical output.

There are many factors that can cause the feedwater temperature to be maintained at sub-optimal levels and thus affect the TTD, DCA and TR measurements, for instance tube fouling, plugged tubes, inadequate venting and tube leakage. The feedwater level inside the feedwater heater has a significant impact on the end temperature of the feedwater, and can be controlled and optimized. In Table 2 the effects of level changes can be seen.

### Table 2. Effects on Feedwater Heater Measures due to Feedwater Level

<table>
<thead>
<tr>
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<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Feedwater level is higher than target</td>
<td>Lower than target</td>
<td>Greater difference</td>
<td>DCA temperature decreases</td>
</tr>
<tr>
<td>Feedwater level is lower than target</td>
<td>Higher than target</td>
<td>Smaller difference</td>
<td>DCA temperature increases</td>
</tr>
</tbody>
</table>

A lower than designed final feedwater temperature will affect the plant negatively. When the level in the feedwater is not at the designed target, the result is always reduced efficiency and increased net unit heat rate. In both conditions the risk of damage to hardware increases and the heat transfer is impaired.

If the level is too high, the condensing zone of the feedwater heater is decreased, and the tubes that should condense the steam sub-cool the condensate instead. This could lead to turbine water induction which would be the worst case scenario.
Turbine water induction can result in water droplets being sent to the turbine, causing substantial damage.

Running the level too low also comes with risks. The drain cooler will be exposed to high temperature steam which causes the condensate to flash to steam. This can result in heater damage. When the level is too low, this also reduces the heat transfer, due to the mix of steam and water blowing through the heater.

There are two probable operator responses to a decreased feedwater temperature:

- If the level is too high or the feedwater heater is out of service, the operator can over-fire the boiler to increase the temperature.
  
  This will increase the fuel consumption and emissions. It will also increase the gas temperature exiting the furnace, which in turn increases the reheat and superheat spray (used for live steam temperature control) resulting in steam that is too hot. This steam increases the steam flow in the turbines and can cause damage to the drain cooler section and possibly also thermal damage to the tubes.

- If the level is too high the operator may open emergency drains to lower the level.
  
  This will cause immediate loss of plant efficiency and can possibly cause damage due to water induction into the turbine, which, as described above, could have catastrophic effects.

**Level measurement in high pressure and high temperature applications**

The importance of measuring the level in high pressure and high temperature steam applications, such as the feedwater heater, cannot be stressed enough. However, it comes with many challenges and puts high demands on measurement technologies. The application will experience both varying temperatures and pressures, especially during startups. The media changes density over the process and this can cause measurement errors of as much as 30% at the highest temperatures. All density based measurement devices, such as displacers and differential pressure transmitters, will need to compensate for these changes to show the true level. To do this there are algorithms that help the control system account for density changes, but the operating pressure must also be known to be able to measure the level.

The media’s dielectric properties will change during the phase change from liquid to steam. When steam is under high pressure, the dielectric of the steam increases and the propagation speed of the microwaves will slow down. This can cause up to 20% error in the level reading if not compensated.

At a high enough temperature and pressure (702°F/372°C and 3120 psi/215 bar), the dielectric constant of the steam increases to the extent that there are no
distinct phases between liquid and steam. At this point the guided wave radar gauge will not be able to identify any surface.

The guided wave radar transmitter directly measures the surface of the liquid. This means that it provides a level measurement that is completely independent of density, thus eliminating the need for any manually programmed settings for the compensation relating to density changes. The transmitters makes these calculations automatically.

Guided Wave Radar is able to compensate for the vapor dielectric in two ways:

- Static vapor compensation
- Dynamic vapor compensation (DVC)

The compensation occurs in the transmitter’s electronics and the correct level is then sent to the control system. For static vapor compensation, the expected operating pressures and temperatures are manually entered when the transmitter is configured and the dielectric changes are compensated for.

With increased use of renewable power, coal plants are changing load more often and the feedwater heater experiences more variation. Because of this, Dynamic Vapor Compensation is a better option since it continuously compensates for changes in the dielectric constant in the vapor space. Dynamic Vapor Compensation (DVC) works by having the target at a fixed distance to measure the vapor dielectric continuously. The transmitter knows where the target is and will expect a corresponding pulse at this location when there is no vapor present. When vapor is present the pulse appears to move further away. The transmitter determines the difference between where the pulse should occur and where it actually occurs, to back-calculate the dielectric constant of the vapor space. This calculation is performed within the transmitter, not in the DCS, and is based on the physical property of the probe. The onboard compensation is therefore always performed in the same way and makes the compensation more accurate and repeatable.

Figure 2. Feedwater Heater with Level Technology
Level monitoring and heat rate

When measuring level in high pressure and high temperature applications, error levels can be high. With Dynamic Vapor Compensation, error levels can be reduced down to 2% or less. Even small deviations can have a major effect on heat rate and profitability. The example below, taken from the field, explains how deviations in final feedwater affect heat rate and annual fuel costs.

Table 3. Temperature Deviations Example

<table>
<thead>
<tr>
<th>Feedwater heater data</th>
<th>Temperature (°F/°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Outlet temperature target</td>
<td>438.4/225.8</td>
</tr>
<tr>
<td>Actual temperature</td>
<td>417.4/214.1</td>
</tr>
<tr>
<td>Difference</td>
<td>-21.0/11.7</td>
</tr>
<tr>
<td>Temperature rise target</td>
<td>81.0/27.2</td>
</tr>
<tr>
<td>Actual temperature rise</td>
<td>64.0/17.7</td>
</tr>
<tr>
<td>Drain cooler approach target</td>
<td>10.0</td>
</tr>
<tr>
<td>Actual drain cooler approach</td>
<td>3.0</td>
</tr>
<tr>
<td>Terminal temperature difference target</td>
<td>10.0</td>
</tr>
<tr>
<td>Actual terminal temperature difference</td>
<td>19.5</td>
</tr>
</tbody>
</table>

By decreasing the level in the tank and restoring the feedwater temperature to the target, the plant was able to improve their heat rate by 47 Btu/kWh, reducing their annual fuel costs by $243,000. By using technology that shows the true level, the application can be tuned to perform optimally and maximal profitability can be reached.
In cases where the final feedwater temperature did not deviate as much from the specified target temperature there were still opportunities for savings. After installing automatic measurement transmitters with dynamic vapor compensation, heat rate improvements from 0.2% up to 1% were reported. This may not seem like much, but for a 500 MW power plant this can mean up to $70,000 in fuel cost savings per year.

In a report from the Electric Power Research Institute (EPRI) it was found that by increasing monitoring of the feedwater heater, the average improvement in heat rate was 30-60 Btu/kWh. The monitoring included measuring of the TTD and DCA, both directly connected to the level in the tank. With these numbers and the formula that was presented earlier, it can easily be calculated that there is a potential of annual fuel savings in the range of between $240,000 to almost $500,000. Accurate level measurements and automated and reliable technology can in the long run yield huge savings.
Safety concerns

Due to the risk for turbine water induction, feedwater heaters have been identified as sources for potential major damage to both turbines and associated drains. It is therefore very important to monitor water level in feedwater heaters to ensure safe and reliable operations. For this critical measurement, it is recommended that multiple devices should be used to provide redundancy in the measurement. According to the America Society of Mechanical Engineers (ASME) at least two separate level control loops should be used on the feedwater heater.

Table 4. Control Loops for Level Measurement Using Three Transmitters\(^{(1)}\)

<table>
<thead>
<tr>
<th>Transmitters Failed</th>
<th>Action Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>0 transmitters failed</td>
<td>Median or all three determines level</td>
</tr>
<tr>
<td>1 out of 3 transmitters failed</td>
<td>High select of remaining good signals (one of three trip signals)</td>
</tr>
<tr>
<td>2 out of 3 transmitters failed</td>
<td>Select remaining transmitter and two out of three protective trips signals</td>
</tr>
<tr>
<td>All transmitters failed</td>
<td>Level controllers revert to manual and hold last good input</td>
</tr>
</tbody>
</table>

Safe operations should always be the first priority for all applications. Following standards and recommendations is strongly advised. Using reliable technology is another measure that will ensure fewer accidents.

Figure 4. Approved Installation

Emerson™ recommends using a SIL2 certified safety system to ensure correct level measurements even in the toughest conditions.

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1. Source: Recommended Practices for the prevention of water damage to steam turbines used for electrical power generation, The American Society of mechanical Engineers.
For more information on Rosemount 5300 GWR Level Transmitters, see EmersonProcess.com/Rosemount/Guided-Wave-Radar/5300