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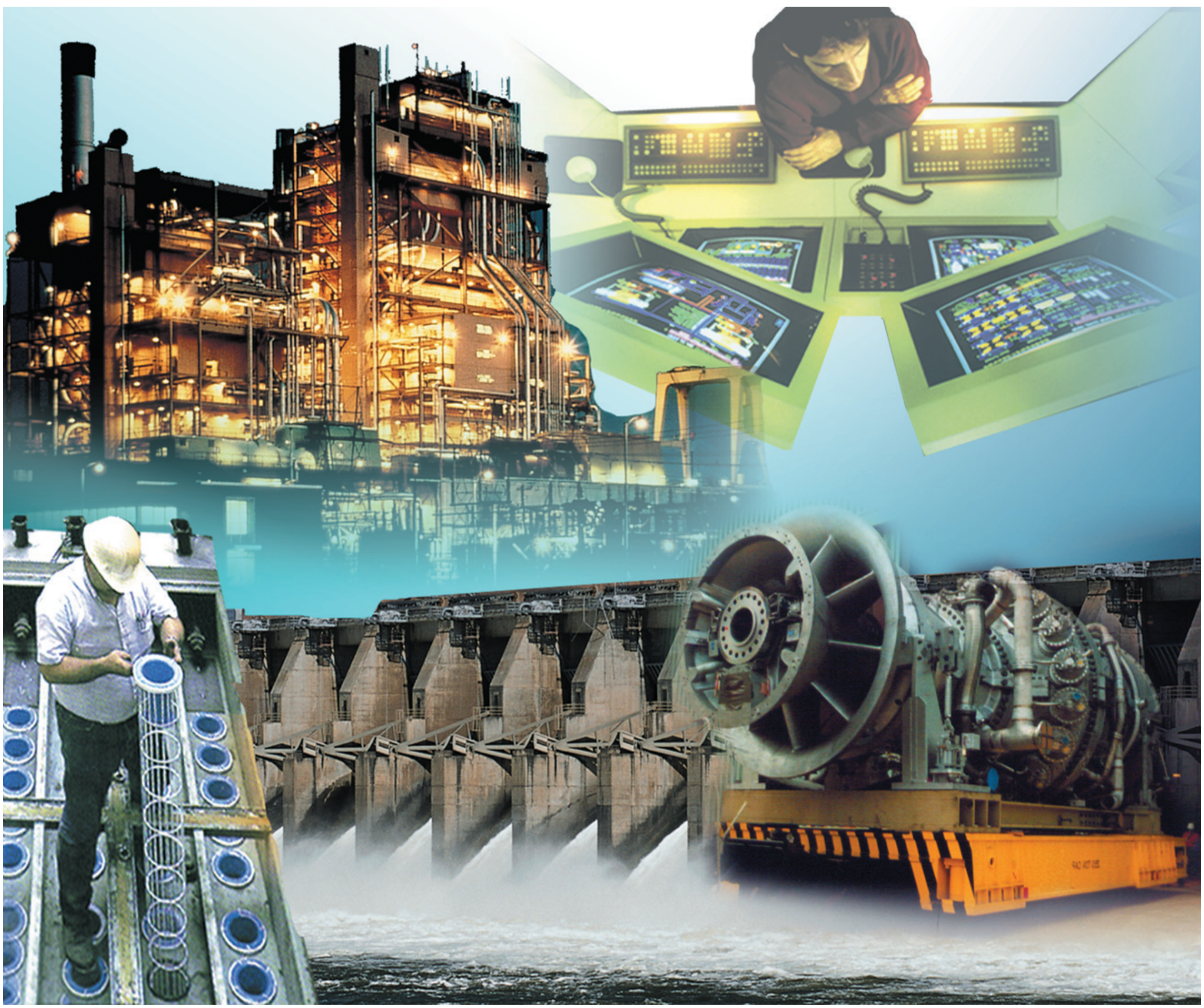
Routine Performance Test Guidelines, Volume 2



Routine Performance Test Guidelines, Volume 2

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Interim Report, August 2010

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REPORT SUMMARY

With the rising cost of fuel and the strong possibility of CO_2 emissions regulations and limitations in the near future, utilities and power generation companies are focusing on power plant heat rate and performance. Improvements in heat rate, which lower fuel costs and decrease emissions, can make a difference in the financial health of a power plant, a power company, and the power industry as a whole. A set of 10 routine test guidelines were developed in 2009; this report provides another set of routine test guidelines, which were developed using the same methodology, for the periodic performance testing of power plant components and systems. Nine separate test guidelines are presented in this report.

Background

Good plant performance programs include testing for determining the health of its components and systems, troubleshooting problems, and optimizing performance. However, due to both cost and staff reductions, testing in power plants has become less frequent despite the importance of optimizing plant heat rate and performance in an era of rising costs and looming CO_2 emission regulations. ASME Performance Test Codes (PTCs) provide procedures for the rigorous tests typically used for acceptance testing of new equipment, but such testing is conducted very infrequently because of its very high cost. In order to provide its members and the industry as a whole with another tool to improve plant performance, the Electric Power Research Institute (EPRI) undertook the development of routine test guidelines, providing less expensive tests that produce results with more uncertainty than the PTCs tests but that can be used more frequently.

Objective

- To provide a set of routine test guidelines for the periodic performance testing of power plant components and systems

Approach

In cooperation with interested EPRI members, the project team developed a list of routine tests of plant performance for which guidelines have been developed over a two-year period and defined a standard outline for test guidelines. As the first part of a plan to produce a full set of 15–20 guidelines over two-year period, in 2009 the team developed routine test guidelines for 10 separate actions or tests based on industry experience and best practices. In this second year of this effort, the team developed draft routine test guidelines for another nine different separate actions or tests. As in 2009, a large group of utility engineers and industry experts from EPRI members reviewed these drafts and provided recommendations for the fine tuning needed to maximize their usefulness.

Results

These guidelines were developed to permit reliable testing of power plant components that can produce repeatable results. These routine tests can be conducted without major financial or time investments. They are designed to be conducted with a minimal number of people and to produce results that can be used for trending, analyzing, troubleshooting, and optimizing the performance of individual pieces of power plant equipment. Power plant personnel can use the guidelines to conduct tests using common test instruments to generate the primary data with process instruments meeting the remainder of the data requirements.

The procedures in this document are designed for long-term trending of key performance parameters, identifying problems, troubleshooting component or system problems, and optimizing component or system operation and performance. It should be noted that these guidelines are not intended for establishing baseline performance and boundary conditions for retrofit projects or for evaluating contract performance guarantees.

EPRI Perspective

Conducting routine performance tests is an important component of a good plant performance program. The information contained in this report represents a significant collection of information and instructions, including techniques and good practices, related to conducting routine performance testing of power plant components and systems. The components and systems that can be evaluated by this set of tests include:

- Centrifugal pumps
- Coal pipes
- Coal pulverizers
- Fans
- Feedwater heaters
- Steam generators
- Steam jet air ejectors
- Steam turbines

Through the use of these guidelines, EPRI members should be able to conduct routine tests more frequently, improve the results of those tests, and ultimately improve component performance and unit heat rate.

Keywords

Coal pulverizers	Performance test
Pumps	Steam generators
Steam jet air ejectors	Steam turbines

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1
INTRODUCTION AND OVERVIEW

1.1 Background

With the rising cost of fuel and the strong possibility of CO_2 emissions regulations and limitations in the near future, utilities and power generation companies are focusing on power plant heat rate and performance. After deregulation drove cost cutting measures, the recent uncertain financial markets are providing further impetus for power plant owners and operators to focus on optimizing their costs. Since the cost of fuel is 60-80% of the overall cost of producing electricity, improvements in heat rate, which decrease emissions in parallel, can make a difference in the financial health of a power plant, a power company, and the power industry.

Due to both cost and staff reductions, testing in power plants has become less frequent. ASME Performance Test Codes (PTCs) provide procedures for rigorous tests typically used for acceptance testing of new equipment. Because of the costs involved in those tests, they are conducted very infrequently.

Good plant performance programs include testing for determining the health of its components and systems, for troubleshooting problems, and for optimizing performance. EPRI undertook the development of these routine test guidelines to provide their members and the industry another tool to improve plant performance.

1.2 Purpose

The purpose of this report is to provide a set routine test guidelines for the periodic performance testing of power plant components and systems. This report describes the common bases and similarities of the accompanying test guidelines. Current ASME PTCs provide absolute test results with minimal uncertainty, but at a very high cost. These guidelines provide for tests with greater amounts of uncertainty in their results, but as a trade-off can be used on a regular frequency, since the cost of testing would be greatly reduced.

1.3 Key Definitions and Glossary of Terms

1.3.1 Key Definitions

System, component, or test specific terms are defined within guideline for that specific test.

Test Guideline– the outline of a method to determine the relative performance of a component or system

Routine Performance Test – an action that may be employed regularly, without great cost or large labor requirements, to determine the relative performance of a power plant component or system

Test Run – one complete set of data collected as part of a test

Test – a series of test runs sufficient to describe the performance of a system or component

Optimization – the action(s) to identify the settings to attain the operating point where a system achieves its maximum effectiveness

Calibration – the actions to determine or adjust, by comparison to a standard, the relationship of the output of an instrument to a known value

Cycle Alignment – setting of valves and flow paths to ensure the fluid and steam in the steam power cycle is routed in the intended manner

Measurement Uncertainty – the estimated error of a measurement; it defines a band in which the true value probably lies

1.3.2 Glossary of Terms

Performance Test Code – An ASME standard that provides a detailed procedure for the conduct of precision tests providing results with minimal uncertainty. These codes may be referenced in contracts other legal documents.

Centrifugal Pump – a mechanical device that facilitates the movement of a liquid (in power plants, typically water) by imparting energy to the fluid by means of a rotating impellor which typically greatly increases the fluid’s pressure.

Coal Pipe – the system that transports the pulverized coal from the mill to the burner utilizing air as the transport medium.

Coal Pulverizer – a mechanical device that grinds the coal into the consistency of dust.

Fan – a mechanical device that moves large volumes of gas, including air, by means of a rotating impellor but does so with a relatively small increase in gas pressure.

Feedwater Heater – a shell and tube heat exchanger that receives extraction steam drawn from the steam turbine to increase the temperature of the feedwater in advance of the feedwater entering the boiler.

Steam Generator – creates large volumes of steam by heating water in its walls constructed of tubes surrounding a furnace in which fuel(s) are combusted. It may include additional heat transfer surfaces to superheat the steam and pre-heat the feedwater as it enters.

Steam Jet Air Ejector – a device with no moving parts that draws air and non-condensibles from a steam condenser. The device is feed by high pressure steam which flows through converging, diverging nozzles creating an aspiration effect.

Steam Turbine – a mechanical device consisting of rotating and stationary vanes that extracts energy from steam and through an attachment to an electrical generator converts that now rotational energy into electrical energy.

1.4 Acronyms

ABP – Absolute Back Pressure

ASME – American Society of Mechanical Engineers

EPRI – Electric Power Research Institute

PTC – Performance Test Code

RTD – Resistance Temperature Detector

1.5 Unit Conversions

US customary engineering units were used in these guidelines. Please use the following table for conversion to Metric units.

US Customary Units		Metric Units
1 foot	=	0.3048 meter
1 inch	=	2.54 centimeters
1^{o}F	=	0.556^{o}C
1 pound mass (lbm)	=	0.454 kilogram (kg)
1 inch water	=	0.249 kilopascal (kpa)
1 inch Hg	=	3.386 kpa
1 pound per square inch (psi)	=	6.895 kpa
1 pound per cubic foot	=	1.602 kg/m^3

1 British thermal unit (Btu) / lbm	=	2.326 joule/kilogram (J/kg)
1 horsepower (hp)	=	746 Watts (W)
1 horsepower (hp)	=	0.746 kilowatts (kW)
1 Btu/lbm/^{o}F	=	4.187 kJ/kg/^{o}C

2 DEVELOPMENT PROCESS AND DESCRIPTION OF GUIDELINES

2.1 Overview of the Guideline Development Process

The following steps outline the process used to develop the routine test guidelines that accompany this report.

- Testing Needs Identified by EPRI Members
- Develop a List of Components and Systems that should be Tested Routinely
- Develop a Standard Outline for All Routine Test Guidelines
- Write up Draft Guidelines
- Forward the Drafts to Interested EPRI Members and Experts for Review
- Incorporate the Recommendations Received into the Guidelines
- Write this Report, Attaching the Completed Guidelines
- Edit and Publish the Report

The same process was employed last year to develop and publish ten routine test guidelines as the first part of this set of routine plant performance testing guidelines.

2.2 Outline for These Routine Test Guidelines

The following outline was used for all routine test guidelines developed as part of this effort.

1. Purpose
2. Applicability
3. Data Requirements
    - Primary
    - Secondary

4. Test Pre-requisites
   - Instrument Installation
   - Instrument Calibration
   - Stability
   - Cycle Alignment / Operation
5. Test Methodology
   - Data Collection Actions
   - Documentation
6. Determination of Results
   - Data Reduction
   - Methodology and Equations
7. Interpretation of Results
8. Post Test Actions
9. Appendices
   - Definition of Terms
   - References and Sources
   - Options to Reduce Uncertainty
   - Options to Expedite Results

2.3 Information Applicable to These Guidelines

These Test Guidelines were developed to permit reliable testing of power plant components producing repeatable results. These routine tests can be conducted without major financial or time investments. They are designed to be conducted with a minimal number of people and produce results that may be used for trending, analyzing, troubleshooting, and optimizing the performance of individual pieces of power plant equipment.

These guidelines were written to permit power plant personnel to conduct tests utilizing common test instruments for primary data and process instruments for the remainder of the data requirements.

The following paragraphs summarize the information that is generic or applicable to all these guidelines.

2.3.1 Calibration

Some assurance of reliable measurements is necessary to ensure meaningful results. The portable test instruments should have been calibrated at some point in their life. More recent calibration improves the accuracy of the results, but is not necessary. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. He or she may substitute data from a backup source, e.g. the process computer, if a primary value is suspect. Pre and post test calibration of the process data source(s) are not required.

2.3.2 Data Requirements

The data for these routine tests will be acquired from process and test instrumentation. To simplify the tests, these test guidelines strive to use most of the data from process instruments and only the most crucial, key inputs from test instruments. Duplicate sources of information should be used routinely:

- As a back up in case of suspect information, and
- For future follow-up to ensure the process parameters, including those sometimes used for unit control, provide reasonable indications of reality.

Primary data have been identified as those with the largest effect on outcome of the results or have a history of being difficult to measure. A good example of a primary measurement is that of steam generator exit gas temperature. That temperature has a large effect on boiler efficiency and unit heat rate. Due to the volume of flue gas flow, its potential stratification, and the physical size of the ductwork, the measurement is subject to large uncertainties. Therefore the placement and number of instruments play a significant role in the ability to determine the true temperature.

When multiple sources exist from which to collect a specific piece of operating or performance data, the test engineer needs to designate one as primary and others as back-up. While the primary source usually provides the data used in the calculations and receives the lion’s share of attention, those duplicate, back-up data sources are useful as described above.

Specific instrument accuracies and other similar specifications are not stipulated in these guidelines. The use of instruments with high levels of accuracy and a narrow band of repeatability will provide results with less uncertainty but come with a higher cost. That trade-off is the jurisdiction of the test engineer, based on his or her needs and testing budget.

2.3.3 Trending of Results

One of the purposes of testing in accordance with these guidelines is to provide a historical trend of unit and equipment performance. To make the trend and accompanying analyses meaningful, conduct the tests and analyze the results via standard methodologies. Consistent methods will ensure results that are comparable, independent of the time between test runs. Certain pieces of data should be corrected to reference conditions. The reference conditions are those stated in the manufacturer’s contract, design documents, and turbine-generator vendor’s thermal kit. The thermal kits typically contain the heat rate and output correction curves for operation at off-design conditions. If necessary, correction factors may also be developed thermal performance evaluation models.

The results of these tests may be plotted against time on a graph containing historical data. The trends can then be used to determine the rate of change and expected performance in the future.

The uncertainty of the results may also be plotted as an error bar on the trend plot to aid the analyses and to avoid concern with less than statistically significant variations.

2.3.4 Testing Frequency

Recommended test frequencies were not provided. Since these guidelines were developed to permit the conduct of routine performance tests without major time, money, or personnel commitments, the test frequency may be optimized by the power generating company to fit best into their schedule and needs. For example, tests may be conducted immediately before and after a planned outage where work will be performed on a specific component. Another example is the application of the test results as the basis for a performance monitoring program, where testing is done regularly to ensure the input stream to the trend plots continues. The frequency of conducting these tests is dependent upon the needs and resources of each power generating company’s performance program.

2.3.5 Measurement Uncertainty

Measurement uncertainty provides the range in which the true value probably lies. Measurement uncertainty is not a measured value, but instead determined analytically, based on process stability, test methodology, and instrumentation characteristics. The numerical value of measurement uncertainty is not a tolerance and should not be applied as such. The true value may just as likely lie below the tested value as above it (typically by an amount less than or equal to the measurement uncertainty).

To provide the test engineer an indication of test quality, the overall measurement uncertainty can be calculated for each test run. While no expected uncertainty levels are provided for these routine performance test guidelines, by comparing the results of pre and post test uncertainty analyses, insight can be gained on what portions of the test made the largest contribution to overall uncertainty. The test engineer will then have the information to evaluate enhancements to the test, e.g. instrument upgrades, data collection frequency, instrument redundancy. Each specific guideline contains recommendations to reduce the uncertainty of the results and improve the quality of that specific test.

The overall uncertainty contains the contributions of both the instrument biases and process fluctuations. The details of the method to determine this uncertainty value are contained in ASME PTC 19.1.

2.3.6 General References

Routine Performance Test Guidelines. EPRI, Palo Alto, CA, 2009, 1019004.

Performance Test Code 19.1, Test Uncertainty, American Society of Mechanical Engineers, 2005, New York.

Performance Test Code PM, Performance Monitoring Guidelines for Power Plants, American Society of Mechanical Engineers, 2010, New York.

Heat Rate Improvement Reference Manual: Training Guidelines. EPRI, Palo Alto, CA, 1999, TM-114073.

Turbine Cycle Heat Rate Monitoring: Technology and Application. EPRI, Palo Alto, CA, 2006, 1012220.

Heat Rate Improvement Reference Manual. EPRI, Palo Alto, CA, 1998, TR-109546.

Heat Rate Improvement Guidelines for Existing Fossil Plants. EPRI, Palo Alto, CA, 1986, CS-4554.

3
CENTRIFUGAL PUMP PERFORMANCE

Centrifugal Pump Performance Routine Test Guideline

1. Purpose: To determine the performance of a centrifugal pump

2. Applicability: Feedwater and other centrifugal pumps in steam power plants

3. Data Requirements

    - Primary
        - Pressure rise across the pump
        - Pump suction temperature
        - Pump rotational speed
        - Pump motor power, where applicable
        - Total flow rate through pump
        - Atmospheric (barometric) pressure
    - Secondary
        - Pump suction pressure
        - Pump discharge pressure
        - Pump discharge temperature
        - Pump motor current (amperage), where applicable
        - Pump motor voltage, where applicable
        - Pump motor power factor, where applicable
        - Gross generation
        - Date and time of test
        - Rotational speed of the hydraulic coupling, where applicable
        - Leak off flow rate, where applicable
        - Balance drum pressure, where applicable

- Balance drum flow rate, where applicable
- Seal injection flow rate, where applicable

4. Test Pre-requisites

- Instrument Installation

  The measurements of certain parameters are crucial to the determination of pump performance. Complying with the following recommendations for each will reduce uncertainty and provide meaningful and trendable results. The instruments should be located to measure the conditions of the fluid (water) entering and exiting the pump.

  - Pressure Measurements

    For the measurement of pressures that are greater than atmospheric, the instrument should be located at an elevation below that of the process. The instrument tubing should be sloped continuously from the process to the instrument and should be as short as possible. The pressure taps should be located near the pump, but to avoid dynamic effects, at least two pipe diameters upstream and the other at least 2 pipe diameters downstream.

    Consistently and correctly apply the water leg correction to these pressure measurements i.e., subtract the pressure equivalent of the water leg from the measured pressure. (In practice, since all positive pressure instruments should be placed at or below the centerline of the process, the water leg is applying additional pressure to the instrument causing a falsely high indication.)

  - Differential Pressure

    Two differential pressure measurements are of key importance for this test. The measurement of feedwater flow rate has a large effect on test results. It is usually determined through the measurement of a differential pressure across a flow element. The developed pump head is a key result of this test. It is also the result of a differential pressure measurement. Great care should therefore be exercised in the measurement of differential pressures. A differential pressure measurement should be made with a single instrument. (Utilizing two separate pressure gages doubles the uncertainty and can entirely mask the actual value, often causing negative or physically impossible results.) A water leg correction for differential pressure measurements is only applied when the process connection taps are located at different elevations. The water leg correction applied in this case is equal to the difference in elevation between the taps. The pressure taps should be located near the pump, but to avoid dynamic effects at least two pipe diameters upstream and the other at least two pipe diameters downstream.

  - Fluid Flow Rate

    The measurement of the flow of fluid moved by the pump is needed to evaluate its performance. Many large pumps in modern power plants have a permanent flow meter on the pump inlet or discharge piping. These flow meters are typically either orifices or nozzles that create a pressure drop by temporarily restricting the flow. If the instrument and flow element are properly maintained they will produce a reasonable indication of flow rate. If those meters are not operable or not installed, a strap-on ultrasonic flow meter may be used for the period of the test.

- Temperature Measurements

  For these water temperatures, thermocouples or RTDs (Resistance Temperature Device) should be used in thermowells. The thermowells should be located immediately upstream and downstream of the pump, while avoiding any interference with the taps and instruments measuring pressure and flow. If the reading is suspect, the device should be removed from its well, the well cleaned, and the device re-inserted to a depth ensuring contact with the bottom of the well. All thermowells should be immersed to a depth of ¼-½ of the diameter of the process pipe.

  Some pumps move a high flow rate of water at a relatively high pressure. Long thermowells or sheaths will be subject to significant bending forces and should be designed to survive in that service.

- Input Power (motor driven pumps)

  The input power to the pump can be taken from instrumentation on the motor. Use the existing watt-hour meter, or record motor amps, volts, and power factor. The design motor efficiency will be needed for the calculation of pump input power; it should be available in the specifications or vendor manual.

- Pump Speed

  The pump speed can be acquired from the control system. If using the motor synchronous speed, a slip correction should be determined and used.

- Instrument Calibration

  The portable test instruments should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. He or she may substitute data from a backup source, e.g., the process computer, if a primary value is suspect. Calibration of the process data source(s) is not required.

- Stability

  These tests will provide results with less uncertainty if the pump is operating in a steady state condition. Temperature variations experienced during a transient may cause changes to seal leakage, drum, or injection flow rates by an unknown amount, changing total flow rate passing through the pump. During transients the pressure and temperature in the pump may also be unsteady, which can affect fluid density, the pump’s performance, and the test results by an unknown amount. Therefore the pump should be in manual and the unit should be at steady state for a minimum of 10 minutes prior to commencing data acquisition. To ensure steady state, the following criteria should be met:

- pump tested in manual control, not automatic
- rotational speed changes less than 1% per hour
- pump input power changes less than 1% per hour
- fluid flow changes of less than 1% per hour
- min flow line verified to have no flow or is isolated
- inlet temperature changes of less than 5°F per hour

It is recommended to initiate a trend of those parameters via a plant process computer or historian prior to the test.

- Cycle Alignment / Operation

  These tests can be conducted at any load. The preferred result of this test is a pump performance curve and is constructed over a range of flow rates. Therefore several test runs at part load operation of the pump will be needed to establish that curve. Pumps can experience instability at very low loads. It is recommended to avoid operating or testing at loads where instabilities are observed.

  The system should be operated in a normal line up and manner for the test. The minimum flow and/or recirculation valves should be closed during the test periods.

5. Test Methodology

   - Data Collection Actions

     Pump performance tests can be conducted at any generation level, though the pump's performance and therefore the test results are dependent upon the pump rotational speed and the flow rate. The results are comparable those of other test runs if conducted at similar rotational speeds and flow rate.

     Upon attaining the stability requirements and fulfilling the hold to ensure steady state, data acquisition may commence. Data should be collected for a minimum of ten minutes. A minimum of five complete sets of all other primary data should be recorded. Prior to ending the test period, the unit stability trend should be reviewed to ensure steady state was maintained and if possible a trend of the primary test data should also be reviewed to ensure the values and stability are reasonable.

   - Documentation

     The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original.

6. Determination of Results

- Data Reduction
  The differential pressure measurements used to determine flow rate should be taken to the ½ power prior to averaging. All other measurements of each parameter recorded during the test run should be averaged. Temperatures may only be adjusted for known and documented corrections based on calibration records.

- Methodology and Equations

  The pump's performance is typically described by a set of curves including those of developed head, efficiency, and input power as a function of volumetric flow rate. Some pump vendors call volumetric flow rate "capacity," where 100% capacity is equal to the design or expected volumetric flow rate and plot the performance parameters as a function of that capacity. Pump head is typically expressed in feet of water. The conversion from pressure measured in psi to head is:

  H = P * 144 / RHO

  Where:

  H= head, feet of water.

  P is the measured pressure, pounds per square inch (psi).

  RHO is the specific density of the water in the pump, lb/ft^3.

  - Developed Head

    Developed head is a measure of the energy added to the water by the pump. It is the difference between the discharge pressure and the suction pressure. For simplicity, the developed head does not include a contribution from any changes in water velocity between the suction and discharge of the pump.

    DH = 144 * DPR / RHO

    Where:

    DH = Developed head, feet of water.

    DPR is the pressure rise across the pump, psi.

    RHO is the specific density of the water in the pump, lb/ft^3.

  - Speed Corrected Developed Head

    To permit a comparison of results to expected, design, or previous tests, any differences in rotational speed must be accounted for. Centrifugal pump head is directly proportional to the square of the pump rotational speed. The value for design pump rotational speed can be found in vendor literature, e.g., capability curve, or specification sheet.

DHc = DH * (SPEEDexp / SPEEDact)^2

Where:

DHc = Speed corrected developed head, ft H_2O.

DH is the developed head, ft H_2O.

SPEEDexp is the expected (design) pump rotational speed, rpm.

SPEEDact is the pump rotational speed, rpm.

- Input Power

Pump input power is the amount of power required by the pump during the test period. Motor power is that drawn by the motor. If motor power is measured directly via a watthour meter, the motor efficiency must be accounted for. In equation form:

POWERin = POWERmotor * EFFmotor / 100 / .746

Where:

POWERin = power into the pump (hp)
POWERmotor = power into the electric motor (kW)
EFFmotor = the efficiency of the motor (%)

If motor inputs include voltage and current, the following equation should be used, again accounting for motor efficiency:

POWERin = Imotor * Emotor* EFFmotor / 100 / 746

Where:

POWERin = power into the pump (hp)
Imotor = electric current to the motor (amps)
Emotor = electric potential at the motor (volts)
EFFmotor = the efficiency of the motor (%)

For 3 phase motors, the equation for power is:

POWERmotor = Imotor * Emotor* PF * 1.732 / 746

Where:

POWERmotor = power into the electric motor (hp)
Imotor = electric current to the motor (amps)
Emotor = electric potential at the motor (volts)
PF = power factor (unitless)
EFFmotor = the efficiency of the motor (%)

- Speed Corrected Input Power

  To permit a comparison of results to expected, design, or previous tests, any differences in rotational speed must be accounted for. Centrifugal pump power is directly proportional to the cube of the pump rotational speed. The value for design pump rotational speed can be found in vendor literature, e.g., capability curve, or specification sheet.

  POWERc = POWERin * (SPEEDexp / SPEEDact)^3

  Where:

  POWERc = Speed corrected power, (hp).
  POWERin is the input power (hp)
  SPEEDexp is the expected (design) pump rotational speed, rpm.
  SPEEDact is the pump rotational speed, rpm.

- Water Power

  Water power is that delivered to the water by the pump. The calculation of this value is an intermediate step in the determination of pump efficiency.

  POWERwater = DH * FLOW / 550 * 3600

  Where:

  POWERwater = Pump water power, (hp)
  FLOW = Pump flow, lb/hr.
  DH = Developed head, feet of water.

For pumps with multiple outlet flow streams, such as balance drum flow, spray flow, and min flow line flow, determine the water power for each flow stream and use the sum of total power from all flow streams to determine pump efficiency.

- Pump Efficiency

  The pump efficiency describes how much power is delivered to the water as compared to power drawn by the pump.

  EFFpump = POWERwater *100 / POWERin

  Where:

  EFFpump = pump efficiency (%)
  POWERwater is the water power imparted to the fluid (hp)
  POWERin is the power drawn by the pump (hp)

  Speed corrected values should be used as the inputs to pump efficiency when the resultant value will be compared to design or expected.

- Overall Pump Efficiency

  The overall pump efficiency describes how much power is delivered to the water as compared to power drawn by the motor.

  EFFpump = POWERwater *100 / POWERmotor

  Where:
  EFFpump = pump efficiency (%)
  POWERwater is the water power imparted to the fluid (hp)
  POWERmotor is the power drawn by the motor (hp)

  Speed corrected values should be used as the inputs to overall pump efficiency when the resultant value will be compared to design or expected.

- Net Positive Suction Head

  Net Positive Suction Head is the difference between the total suction head at the pump inlet and the saturation pressure of the fluid at that temperature.

  NPSH = (Ps – Psat) * 144 / RHO + Pb * 13.6 / 12 + Pv

  Where:
  NPSH = Net Positive Suction Head (feet of water)
  Ps is the pressure at the pump inlet (psi)
  Pb is the barometric pressure (in HgA)
  Pv is the velocity head (feet of water)
  Psat is the saturation pressure at the pump suction temperature (psi)
  RHO = Specific density of the water at the pump suction, lb/ft^3

  The velocity head is typically small and may be ignored without adversely affecting the results.

7. Interpretation of Results

   The four parameters that best define pump performance are:

   - developed head,
   - delivered capacity,
   - efficiency, and
   - power consumption.

   If the results from the tests at rated capacity (flow) do not indicate a problem, e.g., head and flow match that of the design curve, typically no additional evaluation is necessary. The causes of poorer than expected performance may be determined through the evaluation of the collected data. The interpretation is usually done with a full set of results, that is, a curve of results as a function of capacity.

The speed corrected parameters, e.g., developed head, power, and efficiency should be plotted as a function of capacity (flow) for the entire test series. This plot can be compared to design conditions or previous tests.

Potential sources or causes of pump performance problems:

- If the difference between the actual and expected developed head increases with increasing capacity, it is an indication of reduced internal pump flow area or obstruction in the pump discharge.
- If key performance parameters (power consumption, efficiency, developed head, and capacity) are all lower than expected; it may be an indication of internal seal problems, including excessive wear ring clearance or excessive wear plate clearance.
- If the developed head and efficiency are lower than expected over the capacity range, but power consumption is normal, then increased roughness of internal surfaces may be the cause. A common cause of increased roughness is cavitation.
- If cavitation noise exists, it is probably due to insufficient net positive suction head. Lower NPSH may be caused by:
  - insufficient suction pressure
  - incorrect suction piping design
  - higher than expected pressure drop in suction piping
  - an obstruction upstream of the pump
  - a clogged or dirty inlet screen
  - improper impellor design
- Reduced maximum capacity may be caused by:
  - an obstruction in the suction or discharge piping
  - a clogged or dirty inlet screen
  - lower than expected rotational speed
  - increased or excessive recirculation
  - worn impellor, diffuser, casing, or seal rings
- If the developed head and power consumption indicated values are lower than expected, ensure the rotational speed is not low. If the speed is not at design correct the head and power values prior to comparing them to expected values.
- If maximum capacity has been reduced, but the developed head matches expected at lower capacity levels, there may be an obstruction upstream of the pump.

If the developed head and power consumption is less than design for entire capacity range, it is an indication of impellor damage or degradation.

8. Post Test Actions

   Pumps typically have a larger effect on unit generating capacity than heat rate. The pumps ability to move sufficient amounts of feedwater or condensate have a direct effect on maximum unit capacity. Pumps used for cooling may have a very small effect on auxiliary power consumption, but insufficient flow for component cooling may make a difference in maximum generating capacity in warmer weather. System effects outside of the performance of the pump are often the cause of poorer than expected pump performance. Those non-pump problems include increased system pressure drop and recirculating flows.

   Indications of cavitation, specifically noise, should be confirmed. If real, actions should be taken to resolve, as cavitation can cause damage to the pump internals in addition to limiting pump performance.

   Power plant pumps are not of sufficient size to permit easy entry for internal inspections. The disassembly of a pump is a complex and time consuming task. Dimensional tolerances and impellor degradation should be checked, whenever the pump is opened for inspection.

   Ensure the pump is rotating in the proper direction prior to any in-depth evaluation of abnormal pump performance.

9. Appendices

   - Definition of Terms
     - Centrifugal pump is a fluid mover where the discharge flow is perpendicular to the rotation of the pump.
     - Capacity is the volumetric flow rate discharged by the pump.
     - Head is the mechanical energy content of the fluid expressed in terms of height above an arbitrary base.
     - Shut-off Head is the head developed by the pump at zero capacity.
     - Run-out occurs when the pump is operated at its maximum capacity, and usually corresponds to a minimal head.
     - Net Positive Suction Head is the difference between the total suction head at the pump suction and the saturation pressure of the fluid at that temperature.

   - References and Sources
     - ASME Documents

       – PTC 8.2 – 1990 Centrifugal Pumps
       – PTC PM – 2010 Performance Monitoring Guidelines for Steam Power Plants

     - EPRI Documents

       – Feedpump Operation and Design Guidelines, EPRI Report TR-102102

– Pump Troubleshooting, Volume 1, EPRI Report TR-114612

– Condensate Pump Application and Maintenance Guide, EPRI Report 1000052

- Other Documents

  – "Advanced Performance Analysis," General Physics, 2001

- Options to Reduce Uncertainty

In general calibrating the instrument prior to the test runs assures one of reduced uncertainty, but is costly. After the test runs, calibrating only those instruments with or having indicated values outside the expect range is another good practice to improve the reliability of the results. If the post-test calibration indicates a problem, the results can be corrected or another test run conducted. Increasing the test duration and the number of data sets collected, while maintaining both the pump and the unit's stability, will reduce the uncertainty.

For pump testing, the pressure measurements are typically the most important and should be focused on first.

Create four pressure taps on each pipe, connect each tap to a root valve, and form a manifold which is connected to the pressure instrument.

Another option is to base all pressures and water leg corrections to the centerline of the pump discharge.

By dampening the pressure measurements to reduce continuous fluctuations, the recording of data are less apt to occur during a high or low point, providing an average result more representative of reality. Great care should be taken if pressure line dampening is used to ensure the accuracy of the reading is not affected.

Use thermopiles for temperature rise, instead of two separate instruments.

A torque meter can be used on the pump shaft for a direct measurement of input power.

A strobe can be used to determine the rotational speed of the pump shaft. An exposed section of shaft must be available, on which a mark or reflective tape is applied.

Account for the change in water velocity in the determination of developed head.

Account for velocity head in the determination of net positive suction head.

Account for hydraulic coupling losses, where applicable, for input power determination.

For pumps driven by steam turbines, if instrumentation exists, one may determine the inlet power with steam flow, inlet and exhaust steam enthalpies. Those parameters require a flow element on the inlet steam, and temperature and pressure measurements of the inlet and exhaust steam. In some cases, the inlet steam is bled from a main turbine extraction which also feeds a feedwater heater, so the inlet extraction steam conditions for that heater may be used.

- Options to Expedite Results

  Reducing the number of data sets will provide results quicker with an increase in uncertainty.

  Some online performance monitoring systems have internal routines that continuously determine pump performance parameters from process data. Sufficient process data, equivalent to the primary data list, would be required.

  Test only at full load or one flow rate and plot the results against the design curve or compare to previous test results. This provides much quicker results, but with potentially insufficient information to conduct any troubleshooting or analyses.

4
COAL PIPE FINENESS AND FLOW

Coal Pipe Fineness and Flow Routine Test Guideline

1. Purpose: To determine the flow rates and the fineness of the grind in the coal transport pipes.

2. Applicability: Pulverized coal fired power plants.

3. Data Requirements

   - Primary
     - Pitot differential pressure
     - Probe differential pressure
     - Temperature of air in the respective coal transport pipe
     - Coal pipe inner diameter
     - Sample probe inlet inner diameter
     - Static pressure in the coal transport pipe
     - Barometric (ambient) pressure

   - Secondary
     - Feeder speed
     - Coal flow indicated by gravimetric feeder
     - Gross generation
     - Date and time of test

4. Test Pre-requisites

   - Instrument Installation

     The quality of flow measurements and sample is dependent upon properly located taps or sample ports on each coal transport pipe. Those ports should be located on a vertically flowing section of pipe to minimize stratification. A minimum of two ports with 90 degrees separation should be used. Those ports should be located a minimum of 10 diameters downstream and 5 diameters upstream of any elbow or other physical flow disturbance. The inner diameter of the piping at the sampling/measurement locations should be determined as accurately as possible.

Following these recommendations for each measurement will reduce uncertainty and provide meaningful and trendable results.

A pitot tube should be used for the determination of clean air velocity. A dirty air probe, designed to accommodate particulate matter in the flow stream should be used for the determination of dirty air velocity. An aspirated iso-kinetic sampler should be used to collect a coal sample from each pipe for the determination of mass flow and grind fineness. The tips of these probes must be protected. Damage to the tips may change the flow area or produce an unexpected, unknown effect on the differential pressure or sampling capabilities.

Manometers or electronic differential pressure sensor may be used for the differential and static pressures. U-tube or inclined manometers are applicable; the range of the measurements will dictate which to use for each application.

- Instrument Calibration

  The portable test instrument should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. The applicable fluid should be used with each manometer. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. If the test data is suspect, the test should be repeated unless sufficient process data is available. Calibration of the process data source(s) is not required.

- Stability

  These tests will provide results with less uncertainty if the unit is operating in a steady state condition. During transients the coal flow through the pulverizer(s) may surge or lag the air flow, causing temporary, but abnormal results in flow rates and fineness. Temperature variations experienced during a transient will cause a variation in air density and will change the grinding capabilities of the pulverizer. Therefore the pulverizer should be at steady state for a minimum of 20 minutes prior to commencing data acquisition. To ensure steady state, the following criteria will be met:

  – the pulverizer supplying the pipe(s) tested is in manual control

  – coal flow to the pulverizer changes less than 2%/hour

  – gross generation changes of less than 10% / hour

  It is recommended to initiate a trend of those parameters via a plant process computer or historian prior to the test.

- Cycle Alignment / Operation

  The unit, coal pulverizers, and coal transport system should be operated in a normal manner for the test except as described in the section on test methodology. Different operational configurations apply to clean air tests as compared to dirty air tests and coal sampling.

5. Test Methodology

- Data Collection Actions

  Coal pipe testing can be conducted at any generation level, though most concerns with pulverizer performance exist at or near full load. Pulverized fuel transport problems can also occur at low or minimum unit load. Air to Fuel Ratios (AFRAT) are of interest throughout a pulverizer's operating range. For trending purposes air flow and fineness data should be collected at similar generation levels. Prior to ending the test period, the trends of both unit and pulverizer stability should be reviewed to ensure steady state was maintained. If possible the primary test data should also be reviewed to ensure the values are reasonable.

  - Clean Air Testing

    These tests are conducted with NO coal flow through the pulverizer and associated coal transport pipes. Once the coal flow has been secured, the temperature of the air in the pipes should be adjusted to a value within ±10^{o}F of the point of normal operation. Twenty minutes of steady state operation after attaining that temperature, the data collection may begin.

    The pitot should be marked to measure the air velocity across each pipe to represent equal-sized concentric flow areas. The number of flow areas is dependent upon pipe diameter. For pipe diameters outside those listed in the following table, the number of points may be prorated up or down accordingly.

Pipe Diameter	Equal area Zones	Sampling Points
8 inches	4	8
10 inches	5	10
12 inches	6	12

    Before inserting the pitot into the pipe, ensure the manometer is level and indicates a zero reading. The differential pressure developed by the pitot should be recorded for each sample point across the pipe. One set of data should be collected for each coal transport pipe, which at a minimum should include: air temperature, static pressure in the pipe, and barometric pressure.

    Proper pitot alignment is crucial to the generation of pressures representative of actual flow conditions. Ensure the pitot is inserted in the correct direction and position.

  - Dirty Air Testing

    These tests are conducted with normal coal flow through the pulverizer and associated coal transport pipes. All adjustable parameters should be brought into the range of normal operation. Twenty minutes of steady state operation after reaching the normal operating range, the data collection may begin.

The dirty air probe should be marked to measure the air velocity across each pipe to represent equal-sized concentric flow areas. The number of flow areas is dependent upon pipe diameter. For pipe diameters outside those listed in the following table, the number of points may be prorated up or down accordingly.

Pipe Diameter	Equal area Zones	Sampling Points
8 inches	4	8
10 inches	5	10
12 inches	6	12

Before inserting the probe into the pipe, ensure the manometer is level and indicates a zero reading. The differential pressure developed by the dirty air probe should be recorded for each sample point across the pipe. One set of data should be collected for each coal transport pipe, which at a minimum should include: air temperature, static pressure in the pipe, and barometric pressure.

Proper pitot alignment is crucial to the generation of pressures representative of actual flow conditions. Ensure the pitot is inserted in the correct direction and position.

The sensor tubing connecting the probe to the pressure instrument should be disconnected and cleaned (blown out) between each test run.

- Coal Fineness Sampling

  The aspirated sampler uses a side stream of air to create a suction sufficient to draw in the sample at the same velocity as the bulk velocity in the pipe. This isokinetic sampling provides a sample that better represents the bulk of the particulate matter in the coal pipe. The sampler will include the following attributes:

  – Sample / probe tip of known geometry

  – Cyclone separator

  – Sample jar

  – Filter

  – Air flow orifice

  – Inclined manometer

  – Aspirator control valve

  As the sample probe is inserted in and traversed through the pipe, the aspirating air is controlled to maintain a differential pressure equal to that required for the sampling point as determined by the preceding dirty air testing. Proper alignment of the sample probe is crucial to the collection representative samples. Ensure the probe is inserted in the correct direction and position.

Using the same sample zones established for dirty air testing, a sample should be collected for 10 seconds at each point. A different collection time may be used as long as the sample time at each point is equal and recorded.

After completing the pipe traverses, the sensor lines should be shaken to remove any residual coal dust and the sample jar should be emptied into a plastic bag. The bag should be sealed and then labeled with the respective pulverizer, pipe number, and time and date of the test. One should attempt to recover any residual dust on the filter and add it to the labeled sample bag.

The bag should be weighed to determine the mass flow rate.

The sampler should be cleared of all dust between test runs. Dry compressed air is recommended.

- Fineness Sieving

  The coal sample may need drying before successfully sieving it to determine fineness. Drying should be done at low temperatures in order not to “cook” the coal. A 50 gram sample should be separated from that collected. It is recommended to use a riffled splitter to obtain the most representative sample. Clean the following set of sieves:

  – 50 mesh

  – 100 mesh

  – 140 mesh

  – 200 mesh

  – Final pan

  The cleaned and empty sieves and pan should be weighed. The set of sieves should be covered and shaken for 30 minutes. Each sieve and pan should be weighed. The amount of coal passing through each sieve can be determined and then plotted on a Rosin & Rammer graph. The points on the graph should lie on a straight line.

- Documentation

  The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original. After the coal samples have been sieved and data recorded, if a mean exists, the samples may be returned to the feeders or pulverizers.

6. Determination of Results

- Data Reduction

  The square root should be taken of the differential pressures from pitots or probes prior to averaging those values. The numerical measurements of all other parameters recorded during the test run should be averaged.

- Methodology and Equations

  The parameters of interest include the flow rate and velocity of clean air, the flow rate and velocity of dirty air, the coal flow rate, the air to fuel ratio, and the fineness of the grind. The following sections contain descriptions and equations to calculate values for each parameter.

  - Clean Air

    The air specific density should be determined based on the air temperature and pressure.

    Rho = 0.075 * (530 / (T +460)) * ((Pstat/13.6 + Pbar)/29.92)

    Where:

    Rho is the specific density of clean air in the pipe (lbm/ft^3).
    T = temperature of the air in the pipe (^{o}F)
    Pstat = static pressure of the air in the pipe (inches of water)
    Pbar = ambient / barometric pressure (in HgA)

    The velocity can now be determined by the following equation.

    V = K * 1096 * (dP)^1/2 / (rho)^1/2

    Where:

    V is the average air velocity air in the pipe (feet/minute).
    K = the unitless flow coefficient of the pitot (typically 1.000)
    dP = is the difference pressure from the pitot (inches of water)
    Rho = the specific density of clean air in the pipe (lbm/ft^3).

    The mass flow rate of air through the pipe can be determined by the following equation.

  Mair = Rho * A * V * 60

    Where:

    Mair is the mass flow rate of air (lbm/hour)
    Rho = the specific density of clean air in the pipe (lbm/ft^3).
    A = the flow area inside the pipe (feet^2)
    V = the average air velocity air in the pipe (feet/minute).

- Dirty Air

  The dirty air flow rate is determined in the same manner as the clean air flow rate. The probe specific coefficient should be used.

  The air specific density should be determined based on the air temperature and pressure.

  Rho = 0.075 * (530 / (T +460)) * ((Pstat/13.6 + Pbar)/29.92)

  Where:

  Rho is the specific density of clean air in the pipe (lbm/ft^3).
  T = temperature of the air in the pipe (^{o}F)
  Pstat = static pressure of the air in the pipe (inches of water)
  Pbar = ambient / barometric pressure (in HgA)

  The velocity can now be determined by the following equation.

  V = K * 1096 * (dP)^1/2 / (rho)^1/2

  Where:

  V is the average air velocity air in the pipe (feet/minute).
  K = the unitless flow coefficient of the pitot (typically 0.90 to 0.95)
  dP = is the difference pressure from the pitot (inches of water)
  Rho = the specific density of clean air in the pipe (lbm/ft^3).

  The mass flow rate of air through the pipe can be determined by the following equation.

  Mair = Rho * A * V * 60

  Where:

  Mair is the mass flow rate of air (lbm/hour)
  Rho = the specific density of clean air in the pipe (lbm/ft^3)
  A = the flow area inside the pipe (feet^2)
  V = the average air velocity air in the pipe (feet/minute).

- Coal Flow

  The coal flow rate is determined by dividing the mass of the coal collected through isokinetic sampling by the duration of sampling. The fuel recovery rate is ratio of the coal flow rate determined by the amount of coal collected through sampling to the coal flow rate as indicated by the feeder. The gravimetric feeder will indicate a coal mass flow rate. If the pulverizer system does not have gravimetric feeders, an approximation of coal flow must be determined volumetrically based on feeder speed. Feeder manufacturer curves and coal density can be used to estimate coal flow through a feeder.

- Air to Fuel Ratio

  The air to fuel ratio (AFRAT) is determined by dividing the dirty air flow rate by the coal mass flow rate.

- Fineness

  Fineness sieving is typically conducted with 50 gram samples. A slightly different amount can be used, as long as the calculations properly account for the initial amount of coal introduced to the set of sieves. The results are stated in terms of percent passing through the different sieves. The following equations can be used to determine the results.

  Percent passing 50 mesh = (Mi - R50) / Mi *100

  Percent passing 100 mesh = (Mi - R50- R100) / Mi *100

  Percent passing 140 mesh = (Mi - R50 - R100 - R140) / Mi *100

  Percent passing 200 mesh = (Mi - R50 - R100 - R140 - R200) / Mi *100

  Where:

  Mi is the initial amount of coal introduced into the top most sieve (grams)
  R50 is the amount of coal remaining on the 50 mesh sieve (grams)
  R100 is the amount of coal remaining on the 100 mesh sieve (grams)
  R140 is the amount of coal remaining on the 140 mesh sieve (grams)
  R200 is the amount of coal remaining on the 200 mesh sieve (grams)

  The fineness data should be plotted on a Rosin & Rammler graph. The quality of the grind is usually defined by two values: the amounts passing through the 50 mesh and 200 mesh screens. A quick recovery check can be made to reduce errors in calculation or weighing prior to disposing of the samples. Check to see if the quantity Mi - R50 - R100 - R140 - R200 is equal to that remaining in the bottom-most pan.

7. Interpretation of Results

   The clean air velocity in any coal transport pipe should be above 3300 feet/minute or the potential exists for some of the coal particles to drop out of the flow. With velocities below that level, coal dust will drop out in some horizontal piping runs. Uneven or chugging flow may occur as the mounds of coal dust are re-entrained into the bulk flow. If the flow rate remains too low for too long, enough coal dust will drop out of the flow to entirely block the pipe, stopping all flow.

   Unsteady velocities may be the sign of instrument problems or low velocities causing occasional coal dust drop out and re-entrainment.

Balanced coal and air flow rates will improve the combustion process. The industry standards for the balance of coal and air flow rates include:

– Clean Air 2%

– Dirty Air 5%

– Coal Flow 10%

These values describe the maximum difference between the average flow rate for the pipes supplied by one mill to the highest and lowest flowing pipes.

The air to fuel ratio should be within specifications for the mills and system testing, e.g., between 1.8 and 2.0 for bowl mills, 1.3 for ball mills. If AFRAT exceeds those values, wear accelerates in the mill, transport piping, and burners and potentially:

– Boiler performance will suffer as dry gas losses may increase

– Higher NOx formation may occur

– Poorer grind will result

– Slagging and fouling may increase

– Fan capacity limitations may be reached

If AFRAT is too low, boiler efficiency will suffer as flame stability is reduced. With low AFRAT, the potential for other problems exist including:

– Windbox fires

– Accelerated fuel nozzle/burner wear

– Increased burner slagging and fouling

– Low mill outlet temperatures

Recovery Rate: If the recovery rate is much greater than one, then the sampling velocity on the average was greater than that in the pipe, potentially drawing in a disproportionate amount of fine (lighter weight) particles. Conversely a recovery rate much less than one may permit the exclusion of some fine particles. Recovery rates should be between 90 and 110%.

With respect to grind fineness, if the points plotted on Rosin & Rammler graph do not form a straight line, the samples were probably not representative of reality. Problems include:

– Non-isokinetic sampling rate

– Sample splitting or sieving provided a sample with a bias (non representative particle sizing)

– Excessive moisture in the sample

– Calculational errors

– Blending of multiple samples from different coal pipes

If the fineness results do not meet those expected, the problems are typically not associated with measurement errors, but instead with hardware problems associated with the pulverizer feeding the pipes tested. Refer to the test guideline on pulverizer performance for additional details.

8. Post Test Actions

   The flow information can be used to balance the air and coal flows between the pipes from each pulverizer. Resizing or replacing orifices and rifflers and adjusting variable orifices are methods to improve the pipe to pipe balance.

   Trending the flow rates and balance over time provides advanced warning of the resulting combustion problems, including slag formation. Causes of abrupt changes in flow rates should be determined and if unexplainable, additional information gathered by close inspection or testing should be considered. In addition to potential coal pipe pluggage, those changes may be indicative of pulverizer performance problems. Internal inspections of the coal transport piping and the associated flow control mechanisms, e.g., rifflers and orifices, can aid in the troubleshooting process.

   Actions for grind fineness below that expected are centered on the pulverizer itself. Refer to the guideline on pulverizer performance for specific actions. Trending the fineness over time provides advanced warning of an increasing problem with pulverizer performance. Causes of abrupt changes in grind fineness should be determined and if unexplainable, additional information gathered by close inspection or testing should be considered. These changes may be indicative of pulverizer performance problems. Internal inspections of the pulverizer can aid in the troubleshooting process.

   If recovery rates are less than 90% or greater than 110%, the sample collection should be repeated with an appropriate adjustment to sampling velocity to approach an isokinetic sampling rate.

   The samples should not be returned to the bunkers after processing the results. If methods exist to re-introduce the sampled coal dust into the feeders or pulverizers, this introduction of a few pounds of coal dust will not cause problems.

9. Appendices

   - Definition of Terms
     - Clean air – the flow of air only in a coal transport pipe
     - Dirty air – the flow of air laden with particulate in a transport pipe
     - Fineness – a system to indicate the material size distribution of pulverized coal
     - Recovery rate – the amount of sample acquired compared to that flowing through the system

   - Rosin & Rammler Graph – a method to state probability and therefore population density of discreetly sized particles in a sample. It is a log –log scale with the log of particle size on the x-axis and the log of the percentage of those particles passing through that size screen on the y-axis.

- References and Sources
   - ASME Documents

     – PTC 4.2 – 1969   Coal Pulverizers

     – PTC PM – 2010   Performance Monitoring Guidelines for Steam Power Plants

   - EPRI Documents

     – Enhanced Fuel Conveyance: The Effect of Fuel Flow Balance on Boiler Performance, EPRI Report 1020702

     – Addendum to Guidelines for Fireside Testing, EPRI Report TR-111663

     – EPRI Coal Flow Loop: Evaluation of Extractive Methods – Addendum, EPRI Report 1010319

     – NOx Reduction Assessment for Tangentially Fired Boilers Burning Powder River Basin Coal, EPRI Report 1020658

   - Other Documents

     – ASTM D197 Standard Test Method for Sampling and Fineness Test of Pulverized Coal

- Options to Reduce Uncertainty

  The tips of the pitot, dirty air probe, and sampler must be maintained to ensure proper indications and sampling. Those tips should be visually inspected to ensure they are free of any roughness, burrs, or deformities. The inner diameter of those tips may be measured every 45 degrees to ensure no deformities exist. The tip or pitot/probe should be replaced if they are found to be out of round or damaged.

  Ensure the proper flow coefficient (K) is used in the velocity calculations. While it is typically 1.00 for impact pitots, coefficients for S-type probes range from 0.85 to 0.95.

  Coal dust deposits can quickly accumulate in the coal sampling lines or sensing tubing used for dirty air testing. Increasing the frequency of clearing those lines will improve the sample flow and the indication of differential pressure.

  Increasing the number of sample and traverse ports will provide an improved measurement and sample. This may be necessary in those cases where the location is less than ideal and insufficient upstream and/or downstream diameters exist without flow directional changes. If additional ports are used, they should be equally separated across one side of the pipe (180 degrees). For example, if 4 ports are used, the separation between each should be 45 degrees.

Doubling the number of traverses and therefore readings and/or samples will improve the quality of the measurement and provide confirmation (or not) if the readings are repeatable and therefore more representative of reality.

Rotating sampling probes can be used to acquire coal samples in areas where a rope or other flow mal-distribution may exist.

Improving the operating stability of the unit and pulverizer associated with the pipes tested will also provide results with less uncertainty.

- Options to Expedite Results

  Where possible, obtaining a coal sample at the exhauster exit instead of the coal pipe is simpler as it does not require the determination of isokinetic sampling rates. It also permits one sampling traverse instead of one per pipe. This action may provide a non-representative sample if heavy roping or stratified flow exists.

  Having a different sample jar for each pipe to be tested can both speed up the process and reduce errors.

5
FAN PERFORMANCE

Fan Performance Routine Test Guideline

1. Purpose: To determine the performance of a fan

2. Applicability: Centrifugal and axial fans in power plants

3. Data Requirements

    - Primary
        - Fan inlet temperature
        - Fan inlet static pressure
        - Fan outlet temperature
        - Fan outlet static pressure
        - Pressure rise across fan
        - Fan rotational speed
        - Fan motor power
        - Gas constituents if not air
        - Velocity pressures

    - Secondary
        - Fan inlet guide vane (IGV) position, where applicable
        - Fan damper position, where applicable
        - Total flow rate through fan
        - Temperature of ambient air
        - Pressure of ambient air (barometric pressure)
        - Fan motor current (amperage)
        - Fan motor voltage
        - Fan motor power factor, if 3 phase
        - Fan blade pitch, if adjustable

- Gross generation
- Date and time of test

4. Test Pre-requisites

- Instrument Installation

  The measurements of certain pressures are crucial to the determination of fan performance. Complying with the following recommendations for each will reduce uncertainty and provide meaningful and trendable results.

  - Pressure Measurements

    Measure the total and static pressure in the fan inlet and outlet ducts with a grid of probes. The grid should be constructed so each probe "represents" equal areas. Each of these areas should be no larger than 4 square feet. Static pressures should be measured in a manner to ensure the velocity component of the flow does not add or detract from the reading. The grids should be placed in ductwork of near equal area.

    The pressures from each of the probes may be measured with a system consisting of one or more pressure sensing devices and a switching valve station enabling each probe a temporary, but individual connection to the pressure sensing device. The pressures will be in the range of inches of water, making a U-tube manometer a preferred choice of pressure instruments. The availability of electronic pressure sensing instruments will permit more frequent measurements and the application of a data acquisition system.

  - Temperature Measurements

    For bulk gas or air temperatures, thermocouples or RTDs (Resistance Temperature Device) should be used. The ducts through which heated air or gas passes are physically large and stratification may exist. To obtain a representative reading several temperature elements should be placed deeply into the flowing stream. Use of multiple sensors in various depths and locations is recommended to best account for any spatial variations in the duct.

    Little or no variations in temperature will exist in the inlet air, placing several temperature measurements equally spaced across each duct are sufficient to determine the actual temperature of the ambient air entering the fan. But the inlet and exit gas streams may contain temperature stratifications.

    Long thermowells or sheaths will be subject to significant bending forces and erosion due to flyash, and should be designed to survive in that harsh service.

- Flue Gas Constituents

  If the fan is not moving pure air, samples should be taken to determine the constituents of the flue gas. It is preferred to sample the flue gas from the same grid used to measure velocity pressures immediately before or after the test run. If that is not possible or feasible, then a bulk sample should be taken at a location where little stratification exists, preferably downstream of the fan exhaust. Once withdrawn from the duct, the samples should pass through an analyzer to determine gas content.

- Input Power

  The input power to the fan can be taken from instrumentation on the motor. Use the existing watt-hour meter, or record motor amps, volts, and power factor. The design motor efficiency will be needed for the calculation of fan input power; it should be available in the specifications or vendor manual.

- Fan Speed

  The fan speed can be acquired from the control system. If using the motor synchronous speed, a slip correction should be determined and used.

- Flow Area

  The flow area at the plane where inlet pressures are recorded is required to determine the total flow rate through the fan. It can be determined using design drawings or measurements taken when the fan is not operating.

- Instrument Calibration

  The portable test instruments should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. He or she may substitute data from a backup source, e.g., the process computer, if a primary value is suspect. Calibration of the process data source(s) is not required.

- Stability

  These tests will provide results with less uncertainty if the fan is operating in a steady state condition. Temperature variations experienced during a transient may enlarge or contract the gaps that cause air inleakage by an unknown amount, changing total flow rate passing through the fan. During transients the pressure and temperature in the fan may also be unsteady, which can affect density and the results by an unknown amount. Therefore the fan should be in manual and the unit should be at steady state for a minimum of 10 minutes prior to commencing data acquisition. To ensure steady state, the following criteria should be met:

– Fan tested in manual control, not automatic

– Rotational speed changes less than 1% per hour

– Fan input power changes less than 1% per hour

– Gross generation changes of less than 10% per hour

– IGV and damper positions fixed

– Inlet temperature changes of less than 2°F per hour

It is recommended to initiate a trend of those parameters via a plant process computer or historian prior to the test.

- Cycle Alignment / Operation

  These tests can be conducted at any load. The fan performance curve, if desired, is constructed over a range of flow rates therefore part load operation of the fan is needed to plot that curve. Fans can experience instability at low loads. It is recommended to avoid operating or testing at loads where instabilities are observed.

  The boiler should be operated in a normal manner for the test. Soot blowing may cause large temporary temperature variations not reflective of steady state performance, so it is recommended not to conduct any boiler or air heater soot blowing during the data acquisition period when testing ID fans.

5. Test Methodology

- Data Collection Actions

  Fan performance tests can be conducted at any generation level, though the fan's performance and therefore the test results are dependent upon the fan speed and the flow rate. The results are comparable those of other test runs if conducted at similar rotational speeds and flow rate.

  Upon attaining the stability requirements and fulfilling the hold to ensure steady state, data acquisition may commence. Data should be collected for a minimum of 20 minutes or the amount of time required to acquire one full set of pressure measurements. A minimum of 5 complete sets of all other primary data should be recorded. Prior to ending the test period, the unit stability trend should be reviewed to ensure steady state was maintained and if possible a trend of the primary test data should also be reviewed to ensure the values and stability are reasonable.

  Acquiring the pressure measurements can be labor intensive and depending up the number of data points, require a significant period of time. In parallel to the pressure measurements, acquire the remainder of the primary data, e.g., bulk fluid temperatures, input power, and rotational speed; and a sample of the bulk fluid if it is not air.

- Documentation

  The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original.

6. Determination of Results

- Data Reduction

  The individual velocity pressures should be maintained separately, and will be used to determine velocities, which are used to determine kinetic energy, and summed to determine total flow rate. All other measurements of each parameter recorded during the test run should be averaged. Temperatures may only be adjusted for known and documented corrections based on calibration records. The subscript $_i$ in the following equations represents the individual data point measured in the duct(s).

- Methodology and Equations

  The fan performance is typically described by a set of curves including those of output power, total pressure, and efficiency as a function of volumetric flow rate. Some fan vendors call volumetric flow rate "capacity," where 100% capacity is equal to the design or expected volumetric flow rate and plot the performance parameters as a function of that capacity.

  The air or gas velocity is first determined from the grid pressure measurements. Those are summed to find the volumetric flow rate. Output power is determined with volumetric flow rate, the total pressure measured, and the gas compressibility factor. Input power may be measured directly or determined from electrical measurements on the fan motor. Fan efficiency is the ratio of output power to input power. The key parameters of flow rate, total pressure, and output power may be adjusted for actual speed and air/gas density.

  - Air or Gas Velocity

    The air or gas velocity is an input to flow rates and kinetic energy. It is determined from the difference between total and static pressures. The velocity at each point in the measurement plane should be calculated individually. In equation form:

    Vi = 1096 * K * ((Ptotal - Pstatic) / RHO) ^ 1/2

    Where:

    Vi = the air or gas velocity at that point (feet/minute)
    K = the probe calibration coefficient* (-)
    Ptotal = the total pressure at that point (inches water, gage)
    Pstatic = the static pressure at that point (inches water, gage)
    RHO is the specific density** of the air or gas at that temperature (lbm/ft^3)

*The probe calibration coefficient may be taken from actual calibration data or estimated for the type of probe employed. Refer to ASME PTC-11 or other flow measurement reference for the estimated coefficients. Some probe coefficients are the function of Reynolds number, which is dependent upon air/gas velocity, so the determination will be iterative.

** The density of air is readily available in industry tables. For other gases, once the constituents are known, density can be estimated from ideal laws.

- Flow Rate

  The volumetric flow rate of air or gas through the fan is the sum of the flow rates in each of the areas represented by a pressure point. In equation form:

  $$Q = \Sigma \quad (Vi * Ai)$$

  Where:
  - Q = the volumetric flow rate (cubic feet / minute)
  - Vi = the air or gas velocity at that point (feet/minute)
  - Ai = the flow area represented by that point (square feet)

- Output Power

  The rate of energy the fan imparts to the gas or air is a function of the pressure, the gas compressibility, and volumetric flow rate. The gas compressibility factor should not be ignored, as it can affect the results by 10%. Consult ASME PTC 11 or air and gas tables for specific values. The output power calculation in equation form:

  $$POWERout = Q * Ptotal * Kcomp / 6354$$

  Where:
  - POWERout = power imparted to the gas or air (hp)
  - Q = the volumetric flow rate (cubic feet / minute)
  - Ptotal = the total pressure at that point (inches water, gage)
  - Kcomp = compressibility factor (-)

- Input Power

  If motor power is measured directly via a watthour meter, the motor efficiency must be accounted for. In equation form:

  $$POWERin = POWERmotor * EFFmotor / 100 / .746$$

Where:

POWERin = power into the fan (hp)
POWERmotor = power into the electric motor (kW)
EFFmotor = the efficiency of the motor (%)

If motor inputs include voltage and current, the following equation should be used, again accounting for motor efficiency:

POWERin = Imotor * Emotor* EFFmotor / 100 / 746

Where:

POWERin = power into the electric motor (hp)
Imotor = electric current to the motor (amps)
Emotor = electric potential at the motor (volts)
EFFmotor = the efficiency of the motor (%)

For 3 phase motors, the equation for motor power is:

POWERm = Imotor * Emotor* PF * 1.732 / 746

Where:

POWERm = power into the electric motor (hp)
Imotor = electric current to the motor (amps)
Emotor = electric potential at the motor (volts)
PF = power factor (unitless)
EFFmotor = the efficiency of the motor (%)

- Fan Efficiency

The choice on calculating and using total or static efficiency is that of the test engineer. Both provide a measure of fan performance and may be trended over time. Using the parameter contained in design documents or curves will be most useful for comparisons.

The fan total efficiency is based on the total pressure developed. In equation form:

EFFtotalfan = POWERout *100 / POWERin

Where:

EFFtotalfan = fan total efficiency (%)
POWERout = power imparted to the gas or air (hp)
POWERin = power into the fan (hp)

Account for any losses associated with hydraulic coupling if in use, by subtracting those losses from the input power term.

The fan static efficiency is based on the pressure developed referenced to static pressure. In equation form:

EFFstaticfan = EFFtotalfan * Pstatic / Ptotal

Where:

EFFstaticfan = fan total efficiency (%)
EFFtotalfan = fan total efficiency (%)
Pstatic = the static pressure at that point (inches water, gage)
Ptotal = the total pressure at that point (inches water, gage)

- Fan Laws

Fan performance is a function of rotational speed and density. To ensure the results are comparable between test runs conducted at different rotating speed or air/gas density, one may adjust the results in accordance to the following equations:

Qadj = Qact * SPEEDexp / SPEED

Where:

Qadj is the adjusted volumetric flow rate (cubic feet / minute)
Qact is the actual volumetric flow rate (cubic feet / minute)
SPEEDexp is the expected rotational speed (rpm)
SPEED is the actual rotational speed (rpm)

Ptadj = Ptotal * (SPEEDexp / SPEED)^2 * (RHOexp / RHO)

Where:

Ptadj = the adjusted total pressure (inches water, gage)
Ptotal = the total pressure (inches water, gage)
SPEEDexp is the expected rotational speed (rpm)
SPEED is the actual rotational speed (rpm)
RHOexp is the expected specific density of the air or gas (lbm/ft^3)
RHO is the actual specific density of the air or gas at test temperature (lbm/ft^3)

Input power can not be adjusted for rotational speed or air/gas density. To adjust to output power:

POWERadj = POWERout * (SPEEDexp / SPEED)^3 * (RHOexp / RHO)

Where:

POWERadj = adjusted outlet power (hp)
POWERout = actual power imparted to the gas or air (hp)
SPEEDexp is the expected rotational speed (rpm)
SPEED is the actual rotational speed (rpm)

RHOexp is the expected specific density of the air or gas (lbm/ft^3)
RHO is the actual specific density of the air or gas at test temperature (lbm/ft^3)

7. Interpretation of Results

Three parameters best define fan performance: efficiency, capacity, and total pressure. If one deviates from the norm, the others typically follow. The problems are usually related to one or more of the following areas:

– Geometry

– Fouling

– Damage

– Leakage

The fan’s characteristic curve will change, if the geometry of the fan blades or housing changes. Power plant fans are typically optimally designed, so changes to blade dimensions or shape will cause a detrimental effect on fan performance. Erosion and a shortening of the blade tips will reduce capacity and total pressure. Other geometry changes, e.g., to the shroud or housing will cause changes in the flow pattern, reducing the fan efficiency.

In addition to the fan’s rotating speed, outlet dampers and inlet guide vanes (IGV) are used to control the flow through the fan. Their positions have large effects on the fan’s performance. Poor fan performance may be attributed to misaligned dampers or vanes or sets of damper or vanes that are not in sync with each other.

The analogy for axial fans relates to variable pitch fan blades. Fan performance will suffer is the pitch is not controlled correctly or if the set of blades do not move or stay in sync.

In the cases of an over-sized fan for a specific application, operating at a low point on its characteristic curve will result in lower fan efficiency.

If the fan inlet or inlet ductwork is modified, the flow profile entering the fan will change, which may have an effect on fan performance. If that physical modification changes the system pressure drop, the fan will operate at a different point on its characteristic curve.

If the outlet or outlet ductwork is modified, that physical modification may change the system pressure drop, the fan will operate at a different point on its characteristic curve.

If the blade themselves are fouled, the aerodynamics of the fan will be adversely affected and all three performance parameters will decline. If the inlet or outlet ductwork becomes fouled, the additional friction will cause the system pressure drop to increase and the fan will operate at a different point on its characteristic curve.

Refer to the problems related to geometry if the rotating element of the fan is damaged.

A decrease in fan efficiency may be due to:

– Fouling of the blades

– Blade damage / deterioration

– Seal leakage

A decrease in capacity or maximum flow may be due to:

– Increased air inleakage

– Fouling of the blades

– Blade damage / deterioration

– Seal leakage

– Temperature changes driving density changes

– Drop in rotational speed

– Fouling or increased pressure drop in either upstream or downstream components

– Increased wheel to housing clearance

A low or decreasing total pressure indicates:

– Increased air inleakage

– Fouling of the blades

– Blade damage / deterioration

– Seal leakage

– Temperature changes driving density changes

– Drop in rotational speed

– Increased wheel to housing clearance

If the combination of results does not correlate to any of the aforementioned scenarios, check for proper rotation and openings in the ductwork, e.g., manways.

8. Post Test Actions

Fans typically have a larger effect on unit capacity than heat rate. The fans ability to move sufficient amounts of air or gas have a direct effect on maximum unit capacity. System effects outside of the performance of the fan are often the cause of poorer than expected fan performance. Those non-fan problems include increased air inleakage for ID fans, system resistance increases due to fouling or slagging, and higher than normal air or gas temperatures due to either ambient or degraded heat transfer equipment upstream of the fan.

Power plant fans are of sufficient size to permit entry for internal inspections. Inspectors should use all appropriate safety precautions. The inspection can be used to check or verify the dimensions of blades and clearances, inleakage sources, and fouling of the fan rotating element. Cleaning the fan is recommended to improve its performance, though after cleaning, the fan may exhibit increased vibration, due to imbalance.

9. Appendices

- Definition of Terms
  - Axial fan is an air or gas mover, where the flow is parallel to the axis of rotation. Its blades are roughly propeller shaped.
  - Centrifugal fan is an air mover where the discharge air flow is perpendicular to the rotation of the fan. Its rotating element resembles a squirrel cage.
  - Static pressure is pressure of the air or gas after removing the effect of its movement. In a motionless fluid, the static pressure equals the total pressure.
  - Total pressure is also called the stagnation pressure and includes the effect of the movement and the static pressure of the air or gas.
  - Velocity pressure is also called the dynamic pressure. It accounts for the motion of the gas or air and is essentially the kinetic energy per unit volume.
- References and Sources

  - ASME Documents

    – PTC 11 – 2008 Fans

    – PTC PM – 2010 Performance Monitoring Guidelines for Steam Power Plants
  - EPRI Documents

    – Investigation of Field Test Procedures for Large Fans, EPRI Report CS-1651

    – FMAC Forced Draft and Induced Draft Fan Maintenance Guide, EPRI Report 1009651

    – Operation and Maintenance Guidelines for Draft Fans, EPRI Report TR-101698
  - Other Documents

    – US Department of Energy and Air Movement and Control Association (AMCA) “Improving Fan System Performance, a sourcebook for industry” 2003

    – American Society for Heating, Refrigeration, and Air-conditioning Engineers (ASHRAE), “Handbook – Fundamentals,” 2009

- Options to Reduce Uncertainty

  In general calibrating the instrument prior to the test runs assures one of reduced uncertainty, but is costly. After the test runs, calibrating only those instruments with or having indicated values outside the expect range is another good practice to improve the reliability of the results. If the post-test calibration indicates a problem, the results can be corrected or another test run conducted. Increasing the test duration and the number of data sets collected, while maintaining both the fan and the unit's stability, will reduce the uncertainty.

  The air or gas entering the fan can be stratified with respect to temperature. To improve the measurement, increase the number of temperature measurements. Recommendations include:

  – Traverse of the ductwork or

  – Set up a grid of temperature elements to cover a representative sample of the duct

  – Placing thermowells further upstream where the air or gas may be less stratified

  – Measure temperature at the same locations as those used for pressures

  Traversing the duct or increasing the number of points in the pressure grid will provide a data set with much less uncertainty. If traversing the duct, utilizing a 5-hole probe can help account for non-parallel flows.

  By accounting for the width of the tubing in the instrument grid pressure, a more accurate flow area will be determined.

  By dampening the pressure measurements to reduce continuous fluctuations, the recording of data are less apt to occur during a high or low point, providing an average result more representative of reality. Great care should be taken if pressure line dampening is used to ensure the accuracy of the reading is not affected.

  While iterative in nature, the temperature and pressure measurements can be weighted for flow prior to summation or averaging.

  A torque meter can be used on the fan shaft for a direct measurement of input power.

  A strobe can be used to determine the rotational speed of the fan shaft. An exposed section of shaft must be available, on which a mark or reflective tape is applied.

  The area of the plane on which the velocity pressure measurement are made should be equal to that of the entrance (or exit) of the fan.

- Options to Expedite Results

  Reducing the number of data sets will provide results quicker with an increase in uncertainty.

Some online performance monitoring systems have internal routines that continuously determine fan performance parameters from process data. Sufficient process data, equivalent to the primary data list, would be required.

One may measure the pressures and flow in one of two parallel ducts (inlet or outlet), assuming they are equal. Total flow would be double that result. Halving the number of points will reduce the time required for data acquisition.

6 FEEDWATER HEATER LEAK DETECTION

Feedwater Heater Leak Detection Routine Test Guideline

1. Purpose: To confirm or deny the existence of a Feedwater Heater Tube Leak
2. Applicability: All Power Plant Shell and Tube Feedwater Heaters
3. Data Requirements
   - Primary
     - Temperature of feedwater entering the heater
     - Temperature of condensate draining from the heater
     - Pressure of the feedwater entering the heater
     - Heater shell pressure
     - Extraction steam pressure
     - Liquid level in the heater
     - Drain valve position
     - Emergency drain valve position
   - Secondary
     - Feedwater flow rate
     - Gross generation
     - Date and time of test
4. Test Pre-requisites
   - Instrument Installation

   The measurements of certain temperatures and pressure are crucial to the determination of feedwater heater performance. Complying with the following recommendations for each will reduce uncertainty and provide meaningful and repeatable results.

     - Temperature Measurements

       Thermocouples or RTDs (Resistance Temperature Device) should be used in thermowells. If the reading is suspect, the device should be removed from its well, the well cleaned, and the device re-inserted to a depth ensuring contact with the bottom of the well. All thermowells should be immersed to a depth of ¼-½ of the diameter of the process pipe.

- Pressure Measurements

  When measuring steam pressure, a column of liquid (water) will form in the sensor tubing outside the process, above the instrument. The pressure applied by the height of this water leg must be accounted for to determine the process absolute pressure, which is used to determine the steam's thermodynamic properties at that point.

  To minimize the possible errors contributed by water legs:

  – Install the pressure gages to minimize the length of sensor tubing between the process and the instrument.

  – Ensure the water leg has been blown down well in advance of the test to ensure that no air or bubbles exist in the sensor tubing and to ensure the water leg is completely re-established prior to recording data.

  – Measure the difference in elevation between the centerline of the process connection and the instrument.

  – Consistently and correctly apply the water leg correction to all steam pressure measurements i.e., subtract the pressure equivalent of the water leg from the measured pressure. (In practice, since all positive pressure instruments should be placed at or below the centerline of the process, the water leg is applying additional pressure to the instrument causing a falsely high reading.)

  – If the pressure to be measured is less than atmospheric, as it might be for extraction steam for some low pressure heaters, ensure the sensor tubing is sloped towards the process for its entire length. No water leg correction should be applied to these measured pressures. If the instrument indicates vacuum, the atmospheric pressure should be accounted for.

- Instrument Calibration

  The portable test instruments should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. He or she may substitute data from a backup source, e.g., the process computer, if a primary value is suspect. Calibration of the process data source(s) is not required.

- Stability

  These tests will provide results with less uncertainty if the unit is operating in a steady state condition. Unit transients will cause feedwater heater levels to be unsteady. Therefore the unit should be at steady state for a minimum of 10 minutes prior to commencing data acquisition. To ensure steady state, the following criteria will be met:

  – Unit in manual control, not on Automatic Generation Control (AGC)

  – Net generation changes of less than 5% / hour

  – Feedwater or main steam flow changes of less than 5% / hour

  – Extraction pressure variations of less than 5% / hour

  It is recommended to initiate a trend of those parameters via a plant process computer or historian prior to the test.

- Cycle Alignment / Operation

  The extraction steam, heater shell vents, and all cascading drains routed to the feedwater heater should be secured and isolated. Feedwater should continue to flow through the heater. The heater normal and emergency drain valves must be fully functional for this testing. These tests can be conducted at any load. The non-return valve on the extraction steam line should be functional and in service before, during, and after the testing.

5. Test Methodology

- Data Collection Actions

  Feedwater heater tube leak detection can be conducted at any generation, but the leaks will be more obvious with higher feedwater pressure.

  Once extraction steam and all cascading drains are isolated from the heater, temporarily open the emergency drain valve to totally drain all condensate from the heater. After that valve has been closed, a set of data should be recorded every 5 minutes.

  Data collection should continue until:

  – A liquid level change is observed in the heater shell

  – The normal or emergency drain valves automatically open

  – Thirty (30) minutes have passed

  Do NOT permit the liquid level in the heater to reach the alarm point. Quickly rising water level in a feedwater heater may cause water induction and turbine damage.

- Documentation

  The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original.

6. Determination of Results

   - Data Reduction

     All recorded parameters should be plotted versus time. Post test actions will be taken based on these trend plots.

   - Methodology and Equations

     No specific parameters will be calculated for this test. The data collected should be trended as a function of time.

7. Interpretation of Results

   The following conditions if observed during the test period are indications of a tube leak:

   – The heater shell pressure approaches or becomes equal to the inlet feedwater pressure

   – The shell side relief valve(s) open

   – The temperature of the drain is equivalent to that of the feedwater entering the heater

   – The heater level rapidly rises

   – The normal drain valve automatically opens

   – The emergency drain valve automatically opens

   While the heater was in service an increase in terminal difference if observed prior to the testing is indicative of poorer heat transfer, which may be another sign of a tube leak.

   If the heater shell pressure approaches or becomes equal to the extraction steam pressure, the extraction isolation is not secure. If the shell pressure approaches or becomes equal to the pressure of the upstream heater(s) with a cascading drain connection to the heater being tested, the drain line is not secure. The existence of any of these problems does not permit this method to be used for the determination if a tube leak exists or not. If those valves do not maintain the heater in isolation, no conclusions may be drawn from this testing.

8. Post Test Actions

   If a tube leak is confirmed the feedwater should be isolated from the heater as a precaution to prevent the possibility of turbine water induction. Because feedwater pressure is typically high, tube leaks may impinge on adjacent tubes increasing the number of failures over a short period of time. The tube leak(s) should be repaired prior to putting the heater back into service.

If the testing was non-conclusive, perhaps due to the inability to isolate extraction or cascading drain flow, off-line methods may be required to determine if leaks exist and/or their location(s). These methods are briefly described in the section on Options to Reduce Uncertainty.

If no leaks are identified or suspected, the heater may be put back into normal service.

9. Appendices

- Definition of Terms
    - Turbine Water Induction occurs if the water or condensate level in the feedwater heater rises above the heater, into the extraction line, and into the turbine. Severe damage will occur if the turbine rotating buckets impact that column of water.

- References and Sources

    - ASME Documents

        – PTC 12.1 – 2000 Closed Feedwater Heaters

        – PTC 19.3 – 1974 Temperature Measurement

        – TDP-1 – 2006 Recommended Practices for Prevention of Water Damage to Steam Turbines used for Electric Power Generation

        – Heat Exchange Institute, Standards for Closed Feedwater Heaters, 8th Edition, 2006.

    - EPRI Documents

        – Feedwater Heater Technology Conference Proceedings (2007, 2004, 2001…) EPRI Reports 1014165, 10004121, and 1004022.

- Options to Reduce Uncertainty

    To reduce uncertainty, one can use redundant instruments for each primary data point. Calibrating the instrument immediately prior to the test runs assures one of reduced uncertainty, but is costly. One may install a temporary site gage to ensure valid level indication. Increasing the data collection time and the number of data sets collected, while maintaining the heater's stability, will also reduce the uncertainty.

    Another method to check for feedwater heater tube leaks is with water soluble tracer. The tracer chosen should not be soluble in steam and easily detected. The heaters should be in normal operation. To use this method inject the tracer into the feedwater circuit upstream of all the heaters and draw samples from each heater drain. Tracer is found in a drain line indicates a tube or tube sheet leak.

    Conducting testing when the unit is off-line greatly increases the certainty, but costs associated with taking a unit off-line may be prohibitive. A previously planned outage provides a more reasonable window to conduct an off-line test. In those scenarios, it is recommended to repeat the procedure described in section 5 of this document, but with the unit off-line. That ensures no extraction steam or cascading drain flows and the associated potential isolation problems.

- Options to Expedite Results

  Employing all process instruments in the place of field test instruments will decrease the time and labor required for this process. By continuous monitoring of certain feedwater heater operating parameters, one may add or exclude specific feedwater heaters from this testing. Those exhibiting the behaviors that indicate the possibility of a leak should be tested. Those heaters not exhibiting those behaviors should only be tested if confirmation of no leak is requested, as may be done in an acceptance test situation. The indications of the existence of a potential tube leak include:

  – Continuous increase in shell side liquid level while the unit is at steady state operation

  – Continuous increase in the position of the normal drain valve

  – Opening or the increase in the position of the emergency drain valve

  – Increase in terminal difference (TD)

7 HP-IP INTERSTAGE LEAKAGE, LOAD VARIATION METHOD

HP to IP Packing Leakoff Periodic Test Guideline (load variation /slope method)

1. Purpose: To determine the leakage flow rate from the HP turbine to the IP turbine

2. Applicability: Combined HP and IP Steam Turbines in fossil fuel power stations.

3. Data Requirements

   - Primary
     - Main steam temperature
     - Main steam pressure
     - HP turbine first stage shell pressure
     - IP turbine inlet pressure (hot reheat)
     - IP turbine inlet temperature (hot reheat)
     - IP turbine exhaust pressure
     - IP turbine exhaust temperature

   - Secondary
     - HP turbine exhaust pressure (cold Reheat)
     - HP turbine exhaust temperature (cold Reheat)
     - HP turbine first stage steam temperature
     - HP turbine metal temperatures
     - Barometric / local atmospheric pressure
     - Gross generation
     - Main steam or final feedwater flow rate
     - Date and time of test

4. Test Pre-requisites

- Instrument Installation

  The measurements of certain temperatures and pressure are crucial to the determination of IP turbine section efficiency and the leakage between the HP and IP turbines. Following the following recommendations for each will reduce uncertainty and provide meaningful and trendable results.

  - Pressure Measurements

    When measuring steam pressure, a column of liquid (water) will form in the sensor tubing outside the process, above the instrument. The pressure applied by the height of this water leg must be accounted for to determine the process absolute pressure, which is used to determine the steam's thermodynamic properties at that point.

    To minimize the possible errors contributed by water legs:

    – Install the pressure gages to minimize the length of sensor tubing between the process and the instrument.

    – Ensure the water leg has been blown down well in advance of the test to ensure that no air or bubbles exist in the sensor tubing and to ensure the water leg is completely re-established prior to recording data

    – Measure the difference in elevation between the centerline of the process connection and the instrument; and

    – Consistently and correctly apply the water leg correction to all steam pressure measurements i.e., subtract the pressure equivalent of the water leg from the measured pressure. (In practice, since all positive pressure instruments should be placed at or below the centerline of the process, the water leg is applying additional pressure to the instrument causing a falsely high reading.)

  - Temperature Measurements

    Thermocouples or RTDs (Resistance Temperature Device) should be used in thermowells. If the reading is suspect, the device should be removed from its well, the well cleaned, and the device re-inserted to a depth ensuring contact with the bottom of the well. All thermowells should be immersed to a depth of ¼-½ of the diameter of the process pipe.

  - Instrument Calibration

    The portable test instruments should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. He or she may substitute data from a backup source, e.g., the process computer, if a primary value is suspect. Calibration of the process data source(s) is not required.

- Stability

  These tests will provide results with less uncertainty if the unit is operating in a steady state condition. During transients large components in power plants can "store" energy or heat or require additional heat, causing a delay or lag in the steam conditions, which can influence the results by an unknown amount. Therefore the unit should be at steady state for a minimum of 30 minutes prior to commencing data acquisition. To ensure steady state, the following criteria will be met:

  – Unit in manual control, not AGC

  – No control valve movement

  – Gross generation changes of less than 1% / hour

  – Main steam pressure changes of less than 0.5% / hour

  – Feedwater or main steam flow changes of less than 1% / hour

  It is recommended to initiate a trend of those parameters via a plant process computer or historian prior to the test.

  A 2 hour stabilization period is recommended prior to the low load test run.

- Cycle Alignment / Operation

  Two test runs will be conducted at different operating conditions. For the most part the steam generating unit and the main turbine should be operated in a normal line-up/mode of operation during this test. Prior to testing, unit operational system alignments should be set up such that: 1) turbine inlet steam conditions are representative of normal operation or design conditions; and 2) feedwater heater extraction steam supplies operate as close to design conditions of temperature, pressure, and flow as possible. By setting up the unit to operate in this way, the effect on turbine performance by external factors and not associated with the condition of the turbine itself, will be minimized.

  Prior to commencing the test, the turbine and associated feedwater heaters should be walked down to ensure the steam and water systems are properly aligned and the alignment remains unchanged between the test runs. Vent, drain, and bypass valves should be checked to ensure they are in the proper position (e.g., no throttle steam flow is bypassing the HP turbine inlet, and all feedwater heater emergency drains are closed). Abnormal operation of the feedwater system, e.g., leaking emergency drain valves increase the total extraction flow, which can change the downstream turbine pressures and affect the reported section efficiency. If not correctable, these abnormal conditions should be identified; their effect quantified or estimated, and reported with the test results.

The HP-IP packing blowdown valve should be checked to ensure it is not passing flow. Due to the typical inaccessibility of this valve, thermography or other remote temperature sensing methods can be employed to check this valve.

The first test run should be conducted at or near full load conditions with steam temperatures within 3 °F of expected values. Then, unit load should be reduced by at least 30%. All operating parameters should be kept at normal values for this lower unit output test run. Once this operating condition is attained the unit should be held there for 2-4 hours. After the stabilization hold time is passed, a second test run should be conducted. At the conclusion of this test run, normal operation may resume.

5. Test Procedure

- Data Collection Actions

  This guideline presents one of two methods to determine the leakage from the HP to the IP turbines utilizing IP section efficiency data. In this process, the load variation or slope method, the section efficiency test will be conducted at different operating conditions, but under the same instructions provided for these tests in the previously published EPRI guideline. Refer to EPRI Report 1019004, and the guideline for Steam Turbine Section Efficiency.

  The first step is always to determine the IP section efficiency under normal operating conditions. Prior to the second test run reduce unit load by 20-50% and after a 2 hour hold for stabilization, collect the second set of data for the IP turbine.

- Documentation

  The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original.

6. Determination of Results

- Data Reduction

  All measurements of each parameter recorded during the test run should be averaged. All measured pressures shall be converted to absolute values by incorporating the applicable water leg correction and adding atmospheric pressure to gage readings. Temperatures may only be adjusted for known and documented corrections based on calibration records.

- Methodology and Equations

  Actual enthalpies shall be determined for the conditions at the inlet and exhaust of each turbine. An isentropic enthalpy shall be determined using the inlet entropy and the exhaust pressure. IP turbine section efficiency for each test run should be calculated with the following equation:

Eta = (hin – hout) / (hin – houts) x 100%

Where:

Eta is the section efficiency (%)
hin* is the steam enthalpy at the turbine inlet (btu/lb)
hout is the steam enthalpy at the turbine outlet (btu/lb)
houts is the isentropic enthalpy at the outlet pressure and inlet entropy (btu/lb)

*hin is hot reheat enthalpy for the IP turbine section

Then the inlet enthalpy should be changed based on an estimated leakage flow rate. Use a value in the range of 5-10% for the estimated leakage in this next calculation based on the following equation:

hinl = (hhrh + lkg * hl / 100) / (1 + lkg / 100)

Where:

hinl is the steam enthalpy at the turbine inlet accounting for leakage (btu/lb)
hhrh is the hot reheat steam enthalpy measured entering the IP turbine (btu/lb)
lkg is the estimated leakage flow compared to reheat flow in %
hl is the enthalpy of the leakage flow (btu/lb)

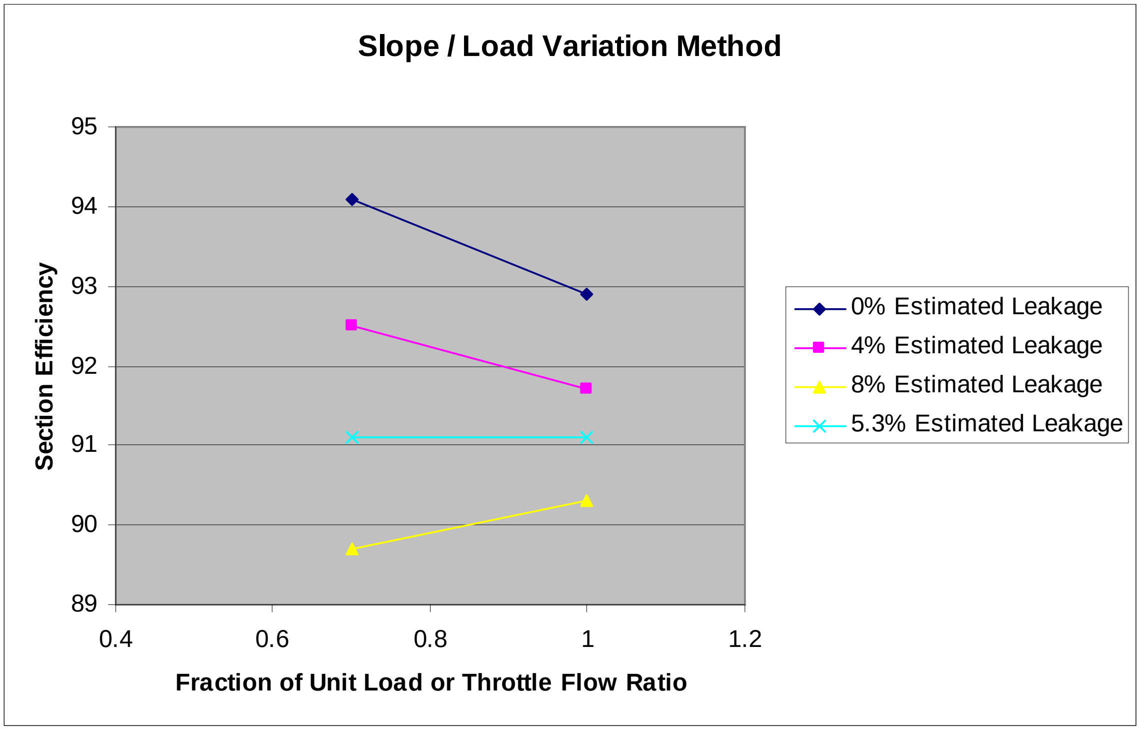
For most instances equating the leakage enthalpy to that of main steam enthalpy will not cause gross errors. For additional precision, refer to the section later in this guideline on methods to reduce the uncertainty.

Substitute the IP inlet enthalpy adjusted for leakage into the standard equation for turbine section efficiency and determine the section efficiency again. Plot the two section efficiencies on a graph as a function unit load or throttle flow ratio and connect the two points with a straight line.

Repeat these steps with the data collected during operation with the load variation. Plot these two points on the same graph and connect them with a straight line. Compare the slopes of those two lines. The goal is to identify a leakage that will produce a line with a 0.0 slope, where the IP section efficiencies at both tested points are equal.

Repeat the steps above, calculating the IP section efficiency at the two throttle flow ratios with different estimated leakages. The estimated leakage used to plot the line with a zero slope denotes the actual leakage.

The following plot contains fictitious data as an example. The results from these fictitious test runs were determined for four different estimated leakages. The estimated leakage of 5.3% resulted in a line with zero slope and indicating that is the leakage rate for this test series.



7. Interpretation of Results

Several iterations may be required to identify the estimated leakage that yields a zero slope. If the estimated leakage has been increased beyond 20% and the slope is still negative, either the turbine leakage is very large or the test results are suspect. Repeat the test to verify the data and/or validate the results.

The leakage rate should be trended over time. Between major turbine overhauls a slow degradation in seal leakage will occur due to normal wear and tear.

A sudden change in seal leakage is an indicator of a mechanical problem. Examples include:

– physically damaged seals caused by events that results in contact with shaft (a rub)

– physically damaged seals caused by solid particle erosion

– physically damaged seals caused by foreign material impingement

– a broken hold-down spring no longer keeping the seal in place

The leakage should decrease dramatically following a turbine overhaul in which seal work was performed. The magnitude of that improvement is a function of the amount of physical work done and the success of those restorations.

Other sources of leakage may include snout rings, the HP turbine inner shell, and the HP turbine horizontal joint.

8. Post Test Actions

   Test results (the HP to IP turbine leakage flow rate) should be trended over time. Causes of abrupt changes should be determined and if unexplainable, additional testing to confirm should be considered. Maintenance or inspection outage scheduling may be based on the trend of leakage rate and an estimated cost of poorer performance as the losses and the outage costs may be compared to the expected recovery and fuel savings to determine the cost-benefit of such actions.

   Records from steam path audits can be used to estimate the losses caused by increased seal clearances.

9. Appendices

   - Definition of Terms
     - Section Efficiency is the amount of energy produced by a section of a turbine compared to the maximum energy that section may have produced.
     - The throttle flow ratio is the throttle flow rate at the test conditions divided by the throttle flow rate at design conditions, typically valves wide open (VWO).
   - References and Sources
     - ASME Documents
       – PTC 6S – 1988 Procedures for Routine Performance Tests of Steam Turbines
       – PTC PM – 2010 Performance Monitoring Guidelines for Steam Power Plants
       – PTC 19.3 – 1974 Temperature Measurement
       – PTC 19.2 – 1987 Pressure Measurement
     - EPRI Documents
       – Turbine Cycle Heat Rate Monitoring: Technology and Application, EPRI Report 1012220
       – Estimating the Leakage from HP to IP Turbine Sections, Booth, J and Kautzman, D, from the 1984 Power Plant Performance Workshop Proceedings EPRI Report CS-4545SR
     - Other Documents
       – A Practical Guide to N2 Packing Testing on GE Combined HP-IP Turbines, Moore, M.S. from the 1992 Heat Rate Improvement Conference Proceedings
       – Recommended Procedures for Measuring HP-IP Turbine Leakage Flow, Haynes, C. J., et.al.

- Options to Reduce Uncertainty

  To reduce uncertainty, one can use redundant instruments for each primary data point. Calibrating the instrument prior to the test runs assures one of reduced uncertainty, but is costly. After the test runs, calibrating only those instruments with or having indicated values outside the expect range is another good practice to improve the reliability of the results. If the post-test calibration indicates a problem, the results can be corrected or another test run conducted. Increasing the test duration and amount of data sets collected, as long as the unit's stability is maintained, will reduce the uncertainty.

  The existence and height of water legs in pressure sensor tubing can be confirmed by the use of portable infra-red or thermography instruments.

  The mass of the turbine is large and metal temperature changes lag behind those of steam temperature. By lengthening the hold time prior to the test run(s) conducted at lower loads, the system may be closer to equilibrium.

  Conducting a third test run at a load much different than the first two, adds a third point to the each plotted line and confirms the slope.

  Taking the temperature measurements on the LP turbine crossover piping instead of the IP turbine exhaust will permit more room for mixing and avoid any effects due to the high temperature of the IP turbine casing.

  While the actual value of the leakage enthalpy has a very small effect on the results, one may use other ways to estimate it more accurately. The first is to locate the value on a design heat balance. Another is to plot the HP expansion on a Mollier diagram to identify the enthalpy at the first stage pressure.

  Substitute throttle flow ratio for load in the graph. To do so determine throttle flow ratio for each test run. The throttle flow is the amount of steam entering the HP turbine first stage. It can be determined by measuring the feedwater or main steam flow rate and accounting for all flows leaving and entering prior to passing through the HP turbine. Depending upon the cycle configuration, flows that should be accounted for may include:

  – boiler blowdown

  – control valve leakages

  – attemperating spray(s)

  – feed pump seal leakage

  – boiler circulating pump seal injection

  – boiler circulating pump seal leakage

Drawing a control volume extending from the measurement point to the HP turbine may help identify the flow paths to be considered. Some of the leakages may be estimated from design documents and the turbine thermal kit.

- Options to Expedite Results

  Employing a spreadsheet with steam table call functions to determine section efficiency from a set of test data, ensures consistency and reduces the time from test run to results. The adjustment to section efficiency for estimated leakage can also be set up into a spreadsheet calculation. Some online performance monitoring systems have internal routines that continuously determine turbine section efficiencies from process data, but will not determine the adjustment.

  Conducting the second test run at a load greater than the recommended 70% may still provide a reasonable estimate of the leakage flow rate, while being easier to achieve. The maximum load for the second test run should be no greater than 80% to provide meaningful results.

8
HP-IP INTERSTAGE LEAKAGE, TEMPERATURE VARIATION METHOD

HP to IP Packing Leakoff Periodic Test Guideline (temperature variation method)

1. Purpose: To determine the leakage flow rate from the HP turbine to the IP turbine

2. Applicability: Combined HP and IP Steam Turbines in fossil fuel power stations.

3. Data Requirements

   - Primary
     - Main steam temperature
     - Main steam pressure
     - HP turbine first stage shell pressure
     - IP turbine inlet pressure (hot reheat)
     - IP turbine inlet temperature (hot reheat)
     - IP turbine exhaust pressure
     - IP turbine exhaust temperature
   - Secondary
     - HP turbine exhaust pressure (cold Reheat)
     - HP turbine exhaust temperature (cold Reheat)
     - HP turbine first stage steam temperature
     - HP turbine metal temperatures
     - Barometric / local atmospheric pressure
     - Gross generation
     - Date and time of test

4. Test Pre-requisites

- Instrument Installation

  The measurements of certain temperatures and pressure are crucial to the determination of IP turbine section efficiency and the leakage between the HP and IP turbines. Following the following recommendations for each will reduce uncertainty and provide meaningful and trendable results.

  - Pressure Measurements

    When measuring steam pressure, a column of liquid (water) will form in the sensor tubing outside the process, above the instrument. The pressure applied by the height of this water leg must be accounted for to determine the process absolute pressure, which is used to determine the steam's thermodynamic properties at that point.

    To minimize the possible errors contributed by water legs:

    – Install the pressure gages to minimize the length of sensor tubing between the process and the instrument.

    – Ensure the water leg has been blown down well in advance of the test to ensure that no air or bubbles exist in the sensor tubing and to ensure the water leg is completely re-established prior to recording data

    – Measure the difference in elevation between the centerline of the process connection and the instrument; and

    – Consistently and correctly apply the water leg correction to all steam pressure measurements i.e., subtract the pressure equivalent of the water leg from the measured pressure. (In practice, since all positive pressure instruments should be placed at or below the centerline of the process, the water leg is applying additional pressure to the instrument causing a falsely high reading.)

  - Temperature Measurements

    Thermocouples or RTDs (Resistance Temperature Device) should be used in thermowells. If the reading is suspect, the device should be removed from its well, the well cleaned, and the device re-inserted to a depth ensuring contact with the bottom of the well. All thermowells should be immersed to a depth of ¼-½ of the diameter of the process pipe.

- Instrument Calibration

  The portable test instruments should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. He or she may substitute data from a backup source, e.g., the process computer, if a primary value is suspect. Calibration of the process data source(s) is not required.

- Stability

  These tests will provide results with less uncertainty if the unit is operating in a steady state condition. During transients large components in power plants can “store” energy or heat or require additional heat, causing a delay or lag in the steam conditions, which can influence the results by an unknown amount. Therefore the unit should be at steady state for a minimum of 30 minutes prior to commencing initial data acquisition. To ensure steady state, the following criteria will be met:

  – unit in manual control, not AGC

  – no control valve movement

  – gross generation changes of less than 1% / hour

  – main steam pressure changes of less than 0.5% / hour

  – feedwater or main steam flow changes of less than 1% / hour

  It is recommended to initiate a trend of those parameters via a plant process computer or historian prior to the test.

  A one hour stabilization period is recommended prior to the temperature drop test run.

- Cycle Alignment / Operation

  Two test runs will be conducted at different operating conditions. For the most part the steam generating unit and the main turbine should be operated in a normal line-up/mode of operation during this test. Prior to testing, unit operational system alignments should be set up such that: 1) turbine inlet steam conditions are representative of normal operation or design conditions; and 2) feedwater heater extraction steam supplies operate as close to design conditions of temperature, pressure, and flow as possible. By setting up the unit to operate in this way, the effect on turbine performance by external factors and not associated with the condition of the turbine itself, will be minimized.

  Prior to commencing the test, the turbine and associated feedwater heaters should be walked down to ensure the steam and water systems are properly aligned and the alignment remains unchanged between the test runs. Vent, drain, and bypass valves should be checked to ensure they are in the proper position (e.g., no throttle steam flow is bypassing the HP turbine inlet, and all feedwater heater emergency drains are closed). Abnormal operation of the feedwater system, e.g., leaking emergency drain valves increase the total extraction flow, which can change the downstream turbine pressures and affect the reported section efficiency. If not correctable, these abnormal conditions should be identified; their effect quantified or estimated, and reported with the test results.

The HP-IP packing blowdown valve should be checked to ensure it is not passing flow. Due to the typical inaccessibility of this valve, thermography or other remote temperature sensing methods can be employed to check this valve.

The first test run should be conducted at or near full load conditions with steam temperatures within 3°F of expected values. Then, main steam temperature should be reduced* by about 50°F. Once this operating condition is attained the unit should be held there for at least one hour. After the stabilization hold time is passed, a second test run should be conducted. At the conclusion of this test run, operating parameters should be returned to normal.

* potential methods include increasing attemperation spray flow rate, reducing burner tilts, temporarily suspending soot-blowing of the superheater elements

5. Test Procedure

- Data Collection Actions

  This guideline presents one of two methods to determine the leakage from the HP to the IP turbines utilizing IP section efficiency data. In this process, the temperature variation method, the section efficiency test will be conducted at different operating conditions, but under the same instructions provided for these tests in the previously published EPRI guideline. Refer to EPRI Report 1019004, and the guideline for Steam Turbine Section Efficiency.

  The first step is always to determine the IP section efficiency under normal operating conditions. Prior to the second test run reduce main steam temperature by approximately 50°F and after a one hour or longer hold for stabilization, collect the second set of data for the IP turbine.

- Documentation

  The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original.

6. Determination of Results

- Data Reduction

  All measurements of each parameter recorded during the test run should be averaged. All measured pressures shall be converted to absolute values by incorporating the applicable water leg correction and adding atmospheric pressure to gage readings. Temperatures may only be adjusted for known and documented corrections based on calibration records.

- Methodology and Equations

Actual enthalpies shall be determined for the conditions at the inlet and exhaust of each turbine. An isentropic enthalpy shall be determined using the inlet entropy and the exhaust pressure. IP turbine section efficiency for each test run should be calculated with the following equation:

Eta = (hin – hout) / (hin – houts) x 100%

Where:

Eta is the section efficiency (%)
hin* is the steam enthalpy at the turbine inlet (btu/lb)
hout is the steam enthalpy at the turbine outlet (btu/lb)
houts is the isentropic enthalpy at the outlet pressure and inlet entropy (btu/lb)

*hin is hot reheat enthalpy for the IP turbine section

Then the inlet enthalpy should be changed based on an estimated leakage flow rate. Use a value in the range of 5-10% for the estimated leakage in this next calculation based on the following equation:

hinl = (hhrh + lkg * hl / 100) / (1 + lkg / 100)

Where:

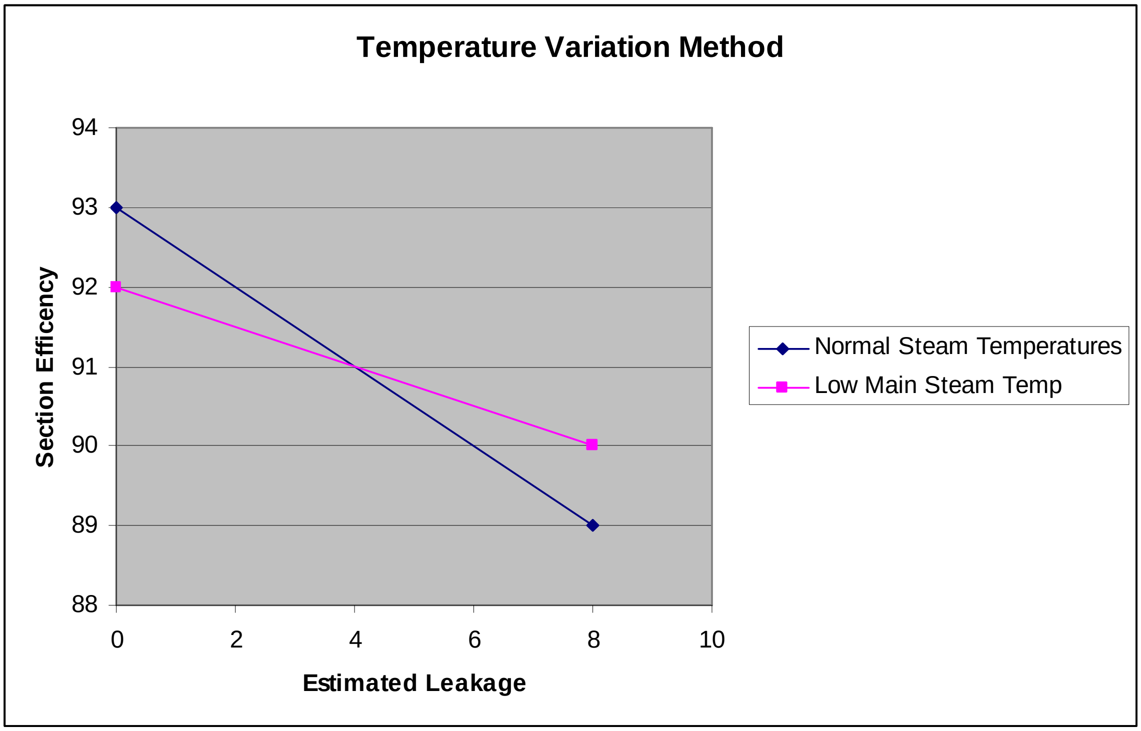
hinl is the steam enthalpy at the turbine inlet accounting for leakage (btu/lb)
hhrh is the hot reheat steam enthalpy measured entering the IP turbine (btu/lb)
lkg is the estimated leakage flow compared to reheat flow in %
hl is the enthalpy of the leakage flow (btu/lb)

For most instances equating the leakage enthalpy to that of main steam enthalpy will not cause gross errors. For additional precision, refer to the section later in this guideline on methods to reduce the uncertainty.

Substitute the IP inlet enthalpy adjusted for leakage into the standard equation for turbine section efficiency and determine the section efficiency again. Plot the two section efficiencies on a graph as a function of leakage and connect the two points with a straight line.

Repeat these steps with the data collected during operation with the temperature variation. Plot these two points on the same graph and connect them with a straight line.

The intersection of the two lines denotes the actual leakage. The following plot contains fictitious data as an example. The results from these fictitious test runs were adjusted for an estimated 8% leakage. These two lines intersect indicating a leakage of 4%.



7. Interpretation of Results

If at first the lines do not intersect, re-calculate the results at a greater estimated leakage. If they do not intersect within 20% leakage, either the turbine leakage is very large or the test results are suspect. Repeat the test to verify the data and/or validate the results.

The leakage rate should be trended over time. Between major turbine overhauls a slow degradation in seal leakage will occur due to normal wear and tear.

A sudden change in seal leakage is an indicator of a mechanical problem. Examples include:

– physically damaged seals caused by events that results in contact with shaft (a rub)

– physically damaged seals caused by solid particle erosion

– physically damaged seals caused by foreign material impingement

– a broken hold-down spring no longer keeping the seal in place

The leakage should decrease dramatically following a turbine overhaul in which seal work was performed. The magnitude of that improvement is a function of the amount of physical work done and the success of those restorations.

Other sources of leakage may include snout rings, the HP turbine inner shell, and the HP turbine horizontal joint.

8. Post Test Actions

   Test results (the HP to IP turbine leakage flow rate) should be trended over time. Causes of abrupt changes should be determined and if unexplainable, additional testing to confirm should be considered. Maintenance or inspection outage scheduling may be based on the trend of leakage rate and an estimated cost of poorer performance as the losses and the outage costs may be compared to the expected recovery and fuel savings to determine the cost-benefit of such actions.

   Records from steam path audits can be used to estimate the losses caused by increased seal clearances.

9. Appendices

   - Definition of Terms
     - Section Efficiency is the amount of energy produced by a section of a turbine compared to the maximum energy that section may have produced.
   - References and Sources
     - ASME Documents
       – PTC 6S – 1988 Procedures for Routine Performance Tests of Steam Turbines
       – PTC PM – 2010 Performance Monitoring Guidelines for Steam Power Plants
       – PTC 19.3 – 1974 Temperature Measurement
       – PTC 19.2 – 1987 Pressure Measurement
     - EPRI Documents
       – Turbine Cycle Heat Rate Monitoring: Technology and Application, EPRI Report 1012220
       – Estimating the Leakage from HP to IP Turbine Sections, Booth, J and Kautzman, D, from the 1984 Power Plant Performance Workshop Proceedings EPRI Report CS-4545SR
     - Other Documents
       – A Practical Guide to N2 Packing Testing on GE Combined HP-IP Turbines, Moore, M.S. from the 1992 Heat Rate Improvement Conference Proceedings
       – Recommended Procedures for Measuring HP-IP Turbine Leakage Flow, Haynes, C J etal

- Options to Reduce Uncertainty

  To reduce uncertainty, one can use redundant instruments for each primary data point. Calibrating the instrument prior to the test runs assures one of reduced uncertainty, but is costly. After the test runs, calibrating only those instruments with or having indicated values outside the expect range is another good practice to improve the reliability of the results. If the post-test calibration indicates a problem, the results can be corrected or another test run conducted. Increasing the test duration and amount of data sets collected, as long as the unit's stability is maintained, will reduce the uncertainty.

  The existence and height of water legs in pressure sensor tubing can be confirmed by the use of portable infra-red or thermography instruments.

  Conduct additional test runs at additional main steam temperatures. Each additional steam temperature will provide another line on the plot. If multiple lines intersect at the same point, the confidence in the results is increased.

  Conduct additional test run(s) with normal main steam temperatures, but with lower than normal hot reheat temperature(s).

  The mass of the turbine is large and metal temperature changes lag behind those of steam temperature. By lengthening the hold time prior to the test run(s) conducted at non-normal steam temperatures, the system may be closer to equilibrium.

  While the actual value of the leakage enthalpy has a very small effect on the results, one may use other ways to estimate it more accurately. The first is to locate the value on a design heat balance. Another is to plot the HP expansion on a Mollier diagram to identify the enthalpy at the first stage pressure.

  Taking the temperature measurements on the LP turbine crossover piping instead of the IP turbine exhaust will permit more room for mixing and avoid any effects due to the high temperature of the IP turbine casing.

- Options to Expedite Results

  Employing a spreadsheet with steam table call functions to determine section efficiency from a set of test data, ensures consistency and reduces the time from test run to results. The adjustment to section efficiency for estimated leakage can also be set up into a spreadsheet calculation. Some online performance monitoring systems have internal routines that continuously determine turbine section efficiencies from process data, but will not determine the adjustment.

  Conducting the second test run at a reduced temperature variation less than the recommended 50°F below normal operating temperature may still provide a reasonable estimate of the leakage flow rate, while being easier to achieve. The temperature variation should be no less than 30°F to provide meaningful results.

9
PULVERIZER PERFORMANCE

Pulverizer Performance Routine Test Guideline

1. Purpose: To determine and evaluate the performance of a coal pulverizer.

2. Applicability: Pulverized coal fired power plants.

3. Data Requirements

   - Primary
     - Temperature of the dirty air leaving the pulverizer
     - Mill motor power or current
     - Barometric (ambient) pressure
     - Coal physical properties
       - Raw coal size entering the pulverizer
       - Hardgrove grindability index
       - Moisture
     - Coal grind fineness (from coal pipe testing, refer to separate guideline)

   - Secondary
     - Feeder speed
     - Coal flow indicated by gravimetric feeder
     - Static pressure in the coal transport pipe
     - Primary air temperature entering pulverizer
     - Primary air flow rate entering the pulverizer
     - Tempering air temperature
     - Tempering air flow rate
     - Voltage in the line to the mill motor, if current readings are taken
     - Mill motor power factor, if three phase

  - Gross generation
  - Date and time of test

4. Test Pre-requisites

- Instrument Installation

  Following these recommendations for each measurement will reduce uncertainty and provide meaningful and trendable results.

  A thermocouple/thermowell combination should be inserted into the dirty air flow for the exit temperature measurement. This should be placed either in a common line, like an exhauster discharge, or each of the coal transport pipes.

  Motor power or current should be measured on the circuit as close to the motor as possible. This is only needed if current measurements are recorded instead of power via a watthour meter.

  A representative sample of the coal entering the pulverizer should be acquired. The sample port should be located downstream of the bunker and upstream of the pulverizer.

  The fineness sampling should be conducted in the coal transport piping in accordance to the guideline on coal pipe testing.

  Manometers may be used for the static and barometric pressures. U-tube or inclined manometers are applicable; the range of the measurements will dictate which to use for each application.

  A thermocouple/thermowell combination should be inserted into the air flows for the hot air inlet and tempering air temperature measurements.

  The flow rates of the two clean air streams entering the pulverizer can be measured by the means chosen by plant operators/owners. Applicable technologies for permanently installed instruments include: converging/diverging nozzles, annubars, and pitots. The ducts can also be traversed with a pitot or probe. With the many physical constraints caused by bends and other flow disturbances, this measurement will probably contain significant uncertainty.

- Instrument Calibration

  The portable test instrument should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. The applicable fluid should be used with each manometer. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. If the test data is suspect, the test should be repeated unless sufficient process data is available. Calibration of the process data source(s) is not required. Gravimetric feeders require frequent calibration and periodic maintenance in order to indicate a reliable coal mass flow rate. Calibrating the weigh cells and ensuring the belt and associated drives are functioning properly will improve the indication.

- Stability

  These tests will provide results with less uncertainty if the unit is operating in a steady state condition. During transients, the coal flow through the pulverizer(s) may surge or lag the air flow, causing temporary, but abnormal results in throughput, flow rates, and fineness. Temperature variations experienced during a transient will cause a variation in air density and will change the grinding capabilities of the pulverizer. Therefore the pulverizer should be at steady state for a minimum of 20 minutes prior to commencing data acquisition. To ensure steady state, the following criteria will be met:

  – the pulverizer tested is in manual control

  – coal flow to the pulverizer tested changes less than 2%/hour

  – net generation changes of less than 10% / hour

  It is recommended to initiate a trend of those parameters via a plant process computer or historian prior to the test.

- Cycle Alignment / Operation

  The unit, coal pulverizers, and coal transport system should be operated in a normal manner for the test.

5. Test Methodology

- Data Collection Actions

  Pulverizer performance testing can be conducted at any generation level, though most concerns with pulverizer performance exist at or near full load. Air to Fuel Ratios (AFRAT) are of interest throughout a pulverizer's operating range. For trending purposes the data should be collected at similar generation levels. Prior to ending the test period, the trends of both unit and pulverizer stability should be reviewed to ensure steady state was maintained. If possible the primary test data should also be reviewed to ensure the values are reasonable.

  If the pulverizer system does not have gravimetric feeders, an approximation of coal flow must be determined volumetrically based on feeder speed. Feeder manufacturer curves and coal density can be used to estimate coal flow through a feeder.

  Upon attaining the stability requirements and fulfilling the hold to ensure steady state, data acquisition may commence. Data should be collected for a minimum of 15 minutes. A minimum of 8 complete sets of primary data should be recorded. Prior to ending the test period, the unit stability trend should be reviewed to ensure steady state was maintained and if possible a trend of the primary test data should also be reviewed to ensure the values and stability are reasonable.

One 500 gram sample of the coal entering the pulverizer should be taken immediately prior or immediately following the data collection. This sample will be used to determine the size, moisture, and hardness of the raw coal entering the pulverizer. Once collected, the sample should be kept in a sealed, air-tight container until the analyses.

Coal pipe testing, e.g., dirty air flow rates and fineness sampling, can be conducted in parallel to the other activities of pulverizer performance testing. Those portions of the testing should occur immediately before, during, or immediately after the primary data acquisition. Please follow the guideline on coal pipe testing for these activities for best results. Clean air tests are not needed in the evaluation of pulverizer performance. They are conducted separately and pertain to the balancing of coal and air flow through the transport piping and not pulverizer performance.

- Documentation

  The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original. After the coal samples have been analyzed or sieved and data recorded, if a mean exists, the samples may be returned to the feeders or pulverizers.

6. Determination of Results

- Data Reduction

  The numerical measurements of each parameter recorded during the test run should be averaged. The results from the analysis of multiple samples may be averaged, but the samples themselves should be kept separate.

- Methodology and Equations

  The parameters of interest include the moisture content, size and grindability of the raw coal, the power consumed by the pulverizer, the coal flow rate through the pulverizer, and the fineness of the grind. The following sections contain descriptions and, where applicable, equations to calculate values for each parameter.

  - Determination of Moisture in the Raw Coal Sample

    This test should be conducted in a lab with personnel acquainted to the ASTM D3302 standard for determining the moisture content of raw coal. Essentially a weighed sample is placed in a desiccating chamber, in which the moisture is drawn out at low temperatures in a controlled (inert) atmosphere, to reduce the loss of volatiles. Upon reaching an equilibrium point, the sample is again weighed; the loss is considered to be equal to the moisture in the sample.

- Determination of the Mean Size of the Raw Coal Sample

  This test should be conducted in a lab with personnel acquainted to the ASTM D4749 standard for determining the size of raw coal. Briefly, a weighed sample of the raw coal is screened or passed through sieves each containing round holes of smaller diameters. The relative particle sizing can be determined by weighing the amount of coal retained on each sieve, as compared to the initial weight of the coal sample.

- Determination of the Hardgrove Grindability Index of the Raw Coal Sample

  This test should be conducted in a lab with personnel acquainted to the ASTM D409 standard for determining the grindability of coal. Briefly, a sample of a specific size, receives a pre-determined amount of grinding in a miniature pulverizer. The size of the resulting pulverized coal sample is determined by sieving. The resultant size is used to assign a relative value to the ease of grinding [Hardgrove Grindability Index (HGI)], where the greater the value of the HGI, the easier the sample was to pulverize.

- Coal Throughput

  The preferred method to determine the coal flow is by direct measurement via a belt scale (gravimetric feeder). For those units without a gravimetric feeder, this determination can be approximated using a volumetric feeder. Outside the test period, the amount of coal that is typically contained in the volume between each of the revolving blades of the feeder should be determined on a mass basis. Assuming those volumes are of equal volume and therefore will contain an equal amount of coal, the flow rate can be determined from the feeder rotating speed, the number of blades on the feeder spool, and its rotational rate.

- Power Consumption

  The preferred method to determine the power consumed by a pulverizer is by direct measurement via a watt-hour meter. For those units without watt-hour meters in place, the current draw of the motor and the line voltage will be measured as part of the test. Those parameters can be used to calculate power by the following equation.

$$\text{POWER} = \text{Imotor} * \text{Emotor} * \text{EFFmotor} / 100 / 746$$

Where:

POWER = power into the electric motor (hp)
Imotor = electric current to the motor (amps)
Emotor = electric potential at the motor (volts)
EFFmotor = the efficiency of the motor (%)

For 3 phase motors, the equation for power is:

POWER = Imotor * Emotor* PF * 1.732 / 746

Where:

POWER = power into the electric motor (hp)
Imotor = electric current to the motor (amps)
Emotor = electric potential at the motor (volts)
PF = power factor (unitless)
EFFmotor = the efficiency of the motor (%)

- Fineness

  In those cases where coal fineness has not been determined in advance, the pulverized coal samples obtained should be subject to the following analysis.

  Fineness sieving is typically conducted with 50 gram samples. A slightly different amount can be used, as long as the calculations properly account for the initial amount of coal introduced to the set of sieves. The results are stated in terms of percent passing through the different sieves. The following equations can be used to determine the results.

  Percent passing 50 mesh = (Mi - R50) / Mi *100
  Percent passing 100 mesh = (Mi - R50- R100) / Mi *100
  Percent passing 140 mesh = (Mi - R50 - R100 - R140) / Mi *100
  Percent passing 200 mesh = (Mi - R50 - R100 - R140 - R200) / Mi *100

  Where:

  Mi is the initial amount of coal introduced into the top most sieve (grams)
  R50 is the amount of coal remaining on the 50 mesh sieve (grams)
  R100 is the amount of coal remaining on the 100 mesh sieve (grams)
  R140 is the amount of coal remaining on the 140 mesh sieve (grams)
  R200 is the amount of coal remaining on the 200 mesh sieve (grams)

  The fineness data should be plotted on a Rosin & Rammler graph. The quality of the grind is usually defined by two values: the amounts passing through the 50 mesh and 200 mesh screens. A quick recovery check can be made to reduce errors in calculation or weighing prior to disposing of the samples. Check to see if Mi - R50 - R100 - R140 - R200 is equal to that remaining in the bottom-most pan.

7. Interpretation of Results

   Pulverizer problems may exist with the following symptoms:

   – Low throughput

   – Poor fineness

   – High power consumption

– Low temperature

– High amounts of rejects

The potential causes of these symptoms are not easily separated.

- Coal Quality

  A low Hard Grove Index correlates to coal that is more difficult to pulverize. High levels of moisture require additional heat to evaporate the water and elevate the temperature. Fineness is typically improved at higher temperatures. If the size of the raw coal fed to the pulverizer is too large additional energy will be spent to crush it. Raw coal size under 1 inch is preferred.

- Classifiers

  If adjustable, the setting on the classifier blades may improve the resulting coal fineness. But even more important, the blades must be in synch, that is they all must be set to the same angle to ensure the clearances are equal, or a portion of the pulverizer may be under-performing.

- Springs

  If the spring force driving the rolls or wheels is less than needed, a poorer grind will occur.

- Rolls and Wheels

  If the rolls and wheels are damaged, worn, uneven, or unmatched; throughput and fineness will be poorer than expected. If grossly worn, the amount of rejects will increase.

- Balls

  If the size and shape of the balls in a ball-mill degrade, the through-put and fineness will degrade. If the number of balls is reduced, performance will be reduced.

- Internal Conditions

  If the clearances and other internal dimensions are not as specified; the pulverizer's performance will degrade. If the inverted cones and other parts have worn or have holes, the flow patterns through the pulverizer will not permit normal performance. Debris lodged inside the pulverizer or other pluggage will degrade performance. If throat areas are too large, the opportunity exists for excessive rejects. Seal ring clearance can affect air flow.

- Hot Air

  If the temperature of the hot air entering the mill is lower than expected, the fineness and outlet temperature will suffer. Low inlet temperature may be an indication of poor air heater performance or too much tempering air flow. If the hot air flow rate is insufficient, the throughput and outlet temperature will suffer. If the hot air flow is too great, fineness will suffer.

- Feed Rate

  If the feed rate is higher than the mill can process, rejects and power consumption will increase and fineness and outlet temperature will suffer.

With respect to grind fineness, if the points plotted on Rosin & Rammler graph do not form a straight line, the samples were probably not representative of reality. Problems include:

– Non-isokinetic sampling rate

– Sample splitting or sieving provided a sample with a bias (non representative particle sizing)

– Excessive moisture in the sample

– Calculation errors

– Blending of multiple samples from different coal pipes

8. Post Test Actions

The test results can be used to guide the post test actions. Since pulverizers performance parameters are interconnected, most of these actions are designed to address multiple issues.

Check the coal quality; size, moisture, and HGI, to ensure they are within specifications. Large differences there will affect pulverizer performance. For example, HGI is proportional to throughput. If raw coal size is a problem, additional crushing may be necessary prior to sending the coal to the bunkers or silos.

Increasing air temperature will improve fineness, but the lubrication for the pulverizer must be able to handle the increase. Increasing the hot air flow rate, while potentially increasing outlet temperature, may be damaging to the fineness due to higher than expected internal velocities. Increasing the air temperature may increase the chance of fires for fuels with significant amounts of volatiles like RPB coal.

Bring the air to fuel ratio into the expected range. This may require an adjustment of control system set points including that for tempering and hot air.

Check spring tension and adjust as needed. In addition to ensuring the magnitude is correct, the setting for all springs on each pulverizer should be equal.

The classifier settings may be adjusted to improve fineness. Some pulverizer designs permit this adjustment without taking the equipment out of service. Other pulverizers may require an equipment outage to enter and adjust. All classifier blades should be in synch with each other, that is their positions or angles should be equal. The air flow rate can be affected if classifier vane angles or vane dimensions are changed. Note: not all pulverizers have classifiers.

Inspect pulverizer internals:

– Ensure classifier vanes are all at the same angle (in synch with each other)

– Check / adjust roll to bowl clearance, where applicable

– Look for any wear or holes in the cones and flow guides and repair as needed.

– Inspect grinding surfaces. They should be smooth and flat where applicable.

– Inspect the rolls, where applicable. Their grinding surfaces should be flat and smooth. They should all be of approximately equal size for each pulverizer.

– Inspect tires, wheels, or balls. They should be smooth, with minimal groves, ridges, or flat spots. They should all be of approximately equal size for each pulverizer. The correct number of balls in each pulverizer should be verified.

9. Appendices

- Definition of Terms
  - Clean air – the flow of air only in a coal transport pipe.
  - Dirty air – the flow of air laden with particulate in a transport pipe.
  - Fineness – a system to indicate the material size distribution of pulverized coal
  - Hardgrove Grindability Index – an arbitrary index used to describe energy required to pulverize coal. A higher value correlates to less energy required and therefore a coal that is easier to pulverize. The range for coal is 40 to 90.
  - Recovery rate – the amount of sample acquired compared to that flowing through the system
  - Rosin & Rammler Graph – a method to state probability and therefore population density of discreetly sized particles in a sample. It is a log –log scale with the log of particle size on the x-axis and the log of the percentage of those particles passing through that size screen on the y-axis.
  - Tempering Air –ambient air drawn into the hot air entering a mill. Used for temperature and flow control.
  - Throughput - the amount of pulverized coal exhausted from a mill.

- References and Sources
  - ASME Documents

    – PTC 4.2 – 1969 Coal Pulverizers

    – PTC PM – 2010 Performance Monitoring Guidelines for Steam Power Plants

- EPRI Documents
  - – Addendum to Guidelines for Fireside Testing, EPRI Report TR-111663
  - – Pulverizer Operational and Performance Upgrades, EPRI Report 1012633
  - – EPRI Coal Flow Loop: Evaluation of Extractive Methods – Addendum, EPRI Report 1010319
  - – Pulverizer and Fuel Delivery Guidelines, EPRI Report 1009490
- ASTM Documents
  - – D197 Standard Test Method for Sampling and Fineness Test of Pulverized Coal
  - – D409 Standard Test Method for Grindability of Coal by the Hardgrove-Machine Method
  - – D3302 Standard Test Method for Total Moisture in Coal
  - – D4749 Standard Test Method for Performing the Sieve Analysis of Coal and Designating Coal Size

- Options to Reduce Uncertainty

  In general calibrating an instrument prior to the test runs assures one of reduced uncertainty, but is costly. After the test runs, calibrating only those instruments with or having indicated values outside the expect range is another good practice to improve the reliability of the results. If the post-test calibration indicates a problem, the results can be corrected or another test run conducted. Increasing the test duration and the number of data sets collected, while maintaining both the pulverizer and the unit's stability, will reduce the uncertainty.

  Increasing the number of raw coal samples will provide a better indication of the coal that passes through the pulverizer during the test period. Acquiring the sample from a flowing stream of coal ensures it is representative of what enters the pulverizer.

  Improving the operating stability of the unit and pulverizer tested will also provide results with less uncertainty.

  The gravimetric feeders require frequent calibration and periodic maintenance in order to indicate a reliable coal mass flow rate. Calibrating the weigh cells and ensuring the belt and associated drives are functioning properly will improve the indication.

  For recommendations with respect to coal pipe testing, please refer to that specific guideline.

- Options to Expedite Results

Raw coal samples may be taken from the belt feeding that bunker in advance of the test. Uncertainty of the flow rate of coal through the bunker may introduce different coal in the pulverizer during the test, potentially causing an error.

For fineness, obtaining a coal sample at the exhauster exit instead of the coal pipe is simpler as it does not require the determination of isokinetic sampling rates. It also permits one sampling traverse instead of one per pipe. This action may provide an unrepresentative sample if heavy roping or stratified flow exists.

Reducing the number of data sets will provide results quicker with an increase in uncertainty.

10
STEAM GENERATOR EFFICIENCY (COAL FIRED)

Coal-Fired Steam Generator (Boiler) Periodic Test Guideline for Efficiency

1. Purpose: To determine the performance of a coal-fired steam generator

2. Applicability: Steam generators (boilers) firing coal

3. Data Requirements

   - Primary
     - Fuel properties (HHV, elemental composition and moisture)
     - Percent carbon in the flyash
     - Exhaust gas constituents (O_2, CO)
     - Exhaust gas temperature
     - Air heater inleakage
     - Inlet air temperature
   - Secondary
     - Temperature of the air entering and exiting the air heater
     - Temperature of the flue gas entering and exiting air heater
     - Temperature of the air entering and exiting pre-heater, if applicable
     - Exhaust gas constituents (CO_2, N_2)
     - Gross generation
     - Main steam temperature
     - Main steam pressure
     - Main steam flow
     - Final feedwater temperature
     - Final feedwater pressure
     - Final feedwater flow
     - Reheat steam flow
     - Superheat spray pressure

- Superheat spray flow
- Reheat spray temperature
- Reheat spray pressure
- Reheat spray flow
- Barometric / local atmospheric pressure
- Boiler blowdown flow
- Unit make-up flow
- Date and time of test

4. Test Pre-requisites

- Instrument Installation

  The measurements of certain parameters are crucial to the determination of boiler efficiency. Following the following recommendations for each will reduce uncertainty and provide meaningful and trendable results.

  - Fuel Properties

    Fuel should be sampled from a flowing stream of the material just prior to entering the pulverizers. In the cases where no pulverizers exist, e.g., cyclone or stoker units, the fuel should be sampled as close as possible to the steam generator. If there is no access to the fuel stream prior to it entering the bunkers, the transport time should be estimated to determine how long before the coal entering the bunker reaches the burner. Accounting for this transport delay time, sampling of the fuel should be timed to ensure the fuel sampled is representative of that fired during the data collection portion of this test.

    Both proximate and ultimate analyses should be conducted on the coal sample. The fuel properties required for this test include:

    – Ash content

    – Carbon content

    – Higher heating value (HHV)

    – Hydrogen content

    – Moisture content

    – Sulfur content

  - Ash Properties

    Flyash should be sampled during the test run, directly from the boiler exhaust. Collecting the sample isokinetically provides a representative sample. The flyash collected should be analyzed to determine the amount of unburned carbon remaining in the ash sample.

- Temperature Measurements

  Thermocouples or Resistance Temperature Devices (RTDs) should be used in thermowells. If the reading is suspect, the device should be removed from its well, the well cleaned, and the device re-inserted to a depth ensuring contact with the bottom of the well. One primary temperature measurement is of flue gas in a large duct. Those thermowells should be inserted as deeply as possible into that space. Use of multiple sensors in various depths and locations is recommended to best account for any spatial variations in the duct. The measurement of ambient or inlet air temperature should be conducted as close as possible to where the air enters the boiler system, e.g., the forced draft (FD) fan inlet.

- Flue Gas Constituents

  It is preferred to sample the flue gas as is exits the economizer. If that is not possible or feasible, then the sample should be taken downstream of the air heater. In the second case, any air inleakage to the air heater must be accounted for in the calculations. In either case, samples should be taken from various locations and depths across the ductwork to ensure the overall sample is representative of the actual exhaust gases. Once withdrawn from the duct, the samples should pass through an analyzer to determine O_2 and CO content. If not measured directly, CO_2 content can be determined using the pivot chart in ASME PTC 4 based on O_2 and CO content. If appropriate, advanced methods, e.g., line of sight, lasers, etc, may be used to determine the flue gas constituents.

- Instrument Calibration

  The portable test instruments should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. He or she may substitute data from a backup source, e.g., the process computer, if a primary value is suspect. Calibration of the process data source(s) is not required.

- Stability

  These tests will provide results with less uncertainty if the unit is operating in a steady state condition. During transients large power plant components like the steam generator can “store” energy or heat or require additional heat, causing a delay or lag in the steam conditions, which can influence the results by an unknown amount. Therefore the unit should be at steady state for a minimum of 30 minutes prior to commencing data acquisition. To ensure steady state, the following criteria will be met:

  – unit in manual control, not on AGC

  – fuel flow (feeder) variations of less than 1% / hour

  – ready and ample supply of fuel

  – net generation changes of less than 1% / hour

– main steam pressure changes of less than 0.5% / hour

– feedwater or main steam flow changes of less than 1% / hour

– reheat temperature variations of less than 3°F / hour

– main steam temperature variations of less than 3°F / hour

It is recommended to initiate and monitor a trend of those parameters via a plant process computer or historian prior to the test.

- Cycle Alignment / Operation

  The steam generating unit should be operated in a normal line-up/mode of operation during this test. The determination of boiler efficiency can be conducted at any generation level.

  Prior to commencing the test, the unit should be walked down to ensure the steam and water systems are properly aligned. Vent, drain, and relief valves should be checked to ensure they closed and not passing flow. Leaking valves, or other abnormal flowpaths or conditions, should be corrected where possible. If not correctable, these abnormal conditions should be identified; their effect quantified or estimated, and reported with the test results.

5. Test Procedure

- Data Collection Actions

  Boiler efficiency can be determined at any generation level. If the results will be used for historical comparisons, conditions external to the boiler should be similar or accounted for.

  Upon attaining the stability requirements and fulfilling the hold to ensure steady state, data acquisition may commence. Data should be collected for a minimum of 45 minutes. A minimum of 2 complete sets of flue gas and fuel samples should be collected. A minimum of 10 complete sets of data should be recorded. One complete set of fly ash samples should be collected. The actual length of the test period will probably be dependent upon the time required to collect flue gas samples. Prior to ending the test period, the unit stability trend should be reviewed to ensure steady state was maintained and if possible a trend of the primary test data should also be reviewed to ensure the values and stability are reasonable.

- Documentation

  The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original.

6. Determination of Results

- Data Reduction

  All measurements of each parameter recorded during the test run should be averaged. Temperatures may only be adjusted for known and documented corrections based on calibration records. Fuel and ash samples should be placed in sealed containers immediately following the test period and sent to a lab for analysis.

- Methodology and Equations

  Boiler efficiency should be determined by the heat loss method which was standardized in ASME PTC 4.1-1964. Individual heat losses and credits will be based on the heating content of the fuel and the reference inlet temperature. For US based coal plants using this procedure, the coal Higher Heating Value (HHV) is used for the heat content of the fuel. Typically the reference temperature is that of the air entering the air heater or the forced draft (FD) fans.

  The most significant losses will be described in the following paragraphs. Some of the losses and credits that typically result in very small values will be described in the section on Options to Reduce Uncertainty as steps that may be taken in addition to the steps in this procedure to fine tune the final results.

  - Dry Gas Losses

    A heat loss occurs due to sensible heat in dry flue gas exiting the steam generator through the stack to the atmosphere. Typically, these dry gas losses amount to about a third of the total boiler losses or about 5% of the total heat input. Moisture in the flue gas also contains heat, but its loss is computed separately as shown below. Sensible heat in the dry flue gas leaving the boiler is a function of exit gas temperature and the total flue gas flow. The magnitude of this loss is potentially controllable by operator actions.

    The dry gas loss is determined by these equations:

    $$Ldg = Wdg * Cpg * (Tgnl – Tref) / HHV * 100$$

    Where:

    L_{dg} Loss due to sensible heat in dry gas, (%)
    W_{dg} Weight of dry flue gas, lb/lb_{fuel} (see equation below)
    C_{pg} Specific heat of dry flue gas (use 0.25), Btu/lb°F
    T_{gnl} Temperature of exit flue gas corrected for air inleakage, °F (see equation below)
    T_{ref} Temperature of air entering the air heater, °F
    HHV Fuel higher heating value, Btu/lb_{fuel}

The dry gas flow is determined by:

$$Wdg = (44^* CO_2 + 32^* O_2 + 28^* (N_2 + CO)) * (C + 0.375^*S) / (12^*(CO_2 + CO)$$

Where:

W_{dg}	Weight of dry flue gas, lb/lb_{fuel}
CO_2	Volume of CO_2 in flue gas, %
O_2	Volume of O_2 in flue gas, %
N_2	Volume of N_2 in flue gas, %
CO	Volume of CO in flue gas, (%)
S	Percent by weight of sulfur in fuel, (%)
C	Weight of carbon burned, (lb/lb_{fuel})

The gas outlet temperature should be corrected using the following relationship.

$$Tgnl = Tg + AIL / 100 * (Tg - Tref)$$

Where:

T_{gnl}	Temperature of exit flue gas, corrected for leakage, °F
T_g	Temperature of exit flue gas, measured, °F
T_{ref}	Temperature of air entering the air heater, °F
AIL	Air heater leakage expressed as percentage of gas entering air heater, % (Refer to the guideline on the determination of air heater air inleakage.)

Air heater leakage is expressed as a percentage of the flue gas mass flow rate entering the air heater. The outlet temperature should be corrected to reflect a non-leakage value to properly account for the heat remaining in the flue gas prior to it exiting the boiler control volume. If the outlet temperature was not corrected for air inleakage the boiler efficiency would be falsely high.

- Moisture Losses (fuel)

A heat loss occurs as the moisture in the fuel is evaporated during the combustion process. That latent heat is not recovered as that moisture does not condense prior to exiting the control volume. Moisture losses are typically 2-4% and directly proportional to the moisture content of the fuel. With this fuel dependency moisture losses are not operator controllable.

The loss due to moisture in fuel is calculated with the following equation:

$$Lmf = M * (hv - hl) / HHV * 100$$

Where:

Lmf	Loss due to moisture in fuel, (%)
M	Weight of moisture in fuel, lb/lb_{fuel}

hv Enthalpy of vapor at 1 psia and corrected exit gas temperature (T_{gnl}), btu/lb
hl Saturated liquid enthalpy at temperature of air entering air heaters (T_{ref}), btu/lb
HHV Fuel higher heating value, btu/lb_{fuel}

- Hydrogen Loss

Similar to the loss brought on by the moisture in the fuel, the combustion of hydrogen produces water. Hydrogen related moisture heat losses may account for about a third of the total boiler losses or approximately 4% of the total heat input. The amount of hydrogen in the fuel is outside operator control.

The loss due to moisture formation from combusting the hydrogen in the fuel is calculated with the following equation:

Lh = 8.9 * H * (hv – hl) / HHV * 100

Where:

Lh Loss due to moisture from combusting the hydrogen in fuel, (%)
H Weight of hydrogen in fuel, lb/lb_{fuel}
hv Enthalpy of vapor at 1 psia and corrected exit gas temperature (T_{gnl}), btu/lb
hl Saturated liquid enthalpy at temperature of air entering air heaters (T_{ref}), btu/lb
HHV Fuel higher heating value, btu/lb_{fuel}

- Unburned Carbon Loss

The loss due to unburned carbon is caused by incomplete combustion. It is a function of the quality of the grind or pulverizer performance, fuel type, and homogeneousness of the air and fuel mixture in the boiler. This loss can be controlled by plant operations to a certain extent. This loss can be kept under 1%.

The loss due to unburned carbon, Luc, is calculated with the following equation:

Luc = A * Wca * 14500 / HHV *100

Where:

Luc Loss due to unburned carbon, (%)
A Weight of ash in coal, lb/lb_{fuel}
Wca Weight of carbon per pound of fly ash, lb/lb_{ash}
HHV Fuel higher heating value, Btu/lb_{fuel}
14,500 Heating value of pure carbon, Btu/lb

- Radiation Losses

  The radiation heat loss encompasses all the lost heat that travels through the boiler casing. It is typically under 0.5% and is not operator controllable, though maintaining the boiler casing and accompanied insulation can minimize the loss. The loss in percent may be read off the ABMA Standard Radiation Loss Chart available through the American Boiler Manufacturer Association or ASME. The loss is a function of boiler rating and operating level.

- Unaccounted for Losses

  The unmeasured or unaccounted for loss includes several losses that are small in magnitude, which can include heat loss in pulverizer rejects, radiation loss to the ash pit, sensible heat loss in bottom ash, sensible heat loss in fly ash, and latent heat of fusion in slag. Although all these losses combined account for only a small portion of the total losses, boiler manufacturers generally include their margin in the unmeasured loss and historically used 1.5% for this value. It is crucial for the reliable trending of the test results to keep this value constant. Determine a value, based on the specific boiler and/or fleet considerations and do not change it from test to test. This loss is considered a constant and not operator controllable.

  The boiler efficiency is then the sum of the losses minus the sum of the credits in total subtracted from 100. In equation form:

  BE = 100 – Sum of Losses (%) + Sum of Credits (%)

  Where BE is boiler efficiency in percent.

  Refer to the section on Options to Reduce Uncertainty for potential credits.

7. Interpretation of Results

   The boiler efficiency should be trended or compared to the expected values based on unit load. If a significant difference exists, further evaluation into the causes may lead one to the potential solutions. If the analysis was conducted via the heat loss method, comparing the actual heat losses to those expected or experienced historically can help to identify the specific areas for further evaluation. As noted in the following paragraphs, furnace exit gas temperature is an indication of combustion performance, but is not a piece of data collected for this test. A strong inter-relationship exists between the performance parameters. For example furnace exit gas temperature directly affects steam temperatures and fouling and therefore boiler efficiency.

   A common problem identified in many boiler efficiency tests is that of high dry gas losses. If the cause is high air heater exit gas temperature, the moisture and hydrogen losses will also be increased. High dry gas losses may be caused by:

– Poor heat transfer due to insufficient soot blowing

– Poor heat transfer due to waterwall fouling

– Poor heat transfer due to superheater or reheater slagging

– High furnace exit gas temperature

– Higher than necessary primary or secondary air flow rates

– Burner tilts set too high (on tangentially fired units)

– Excessive or un-needed use of steam driven air pre-heaters

Higher than expected dry gas losses may be masked by high air inleakage to the air heater which reduce the exiting flue gas temperature by dilution.

Another problem identified in many boiler efficiency tests is that of high steam temperatures. The causes include:

– Poor heat transfer due to insufficient water wall soot blowing

– Poor heat transfer due to waterwall fouling

– High furnace exit gas temperature

– Higher than necessary primary or secondary air flow rates

– Burner tilts set too high (on tangentially fired units)

– Insufficient attemperation flow

Another problem identified in many boiler efficiency tests is that of low steam temperatures. The causes include:

– Poor heat transfer due to insufficient soot blowing

– Poor heat transfer due to superheater or reheater slagging

– Burner tilts set too low (on tangentially fired units)

– Excessive attemperation flow

Many of the prior mentioned problems can be caused by convective pass slagging or fouling. This excessive fouling or slagging may be caused by:

– Poor grind (coal fineness from pulverizers)

– Imbalanced air or fuel flow to the burners

– Unexpected change in fuel composition

– Increased unburned carbon in the ash

– High furnace exit gas temperature

– High boiler air inleakage upstream of O_2 sensors

With proper combustion practices, unburned carbon in the fly ash can be less than 1% for sub-bituminous coal and less than 5% for other coals. Causes of higher than expected unburned carbon levels include:

– Combustion staging used for NOx emissions reduction

– Poor grind (coal fineness from pulverizers)

– Imbalanced air or fuel flow to the burners

– Burner tilts set too high (on tangentially fired units)

– Low primary or secondary air flow rates

– Unexpected change in fuel composition

– High boiler air inleakage upstream of O_2 sensors

High furnace exit gas temperature (FEGT) is an indication of combustion related problems. Causes of high FEGT include:

– Excessive combustion staging for NOx emissions reduction

– Poor heat transfer due to insufficient water wall soot blowing

– Poor heat transfer due to waterwall fouling

– Higher than necessary primary or secondary air flow rates

– Burner tilts set too high (on tangentially fired units)

– High boiler air inleakage upstream of O_2 sensors

Operating with off-design excess air, as indicated by the oxygen level in the convective pass is a detriment to good boiler performance. It can be caused by:

– High boiler air inleakage upstream of O_2 sensors

– Higher than necessary primary or secondary air flow rates

– Higher or lower than expected steam temperatures

Boiler efficiency is a function of unit load; trends and comparisons to historic values should be made with results at similar unit loads.

8. Post Test Actions

The steam generator performance has a direct effect on heat rate. Boiler efficiency as determined above should be trended over time. Causes of abrupt changes should be determined and if unexplainable, additional data collection or testing to confirm should be considered. Internal inspections can aid in the troubleshooting process. Fouling and corrosion of the heat transfer surface areas is a common problem and if encountered should be resolved by cleaning. Intelligent soot blowing strategies may be employed on waterwalls and convective pass element to improve boiler performance. Maintaining a low level of air inleakage will improve air heater performance on both an immediate and longer term basis. Air inleakage can be the cause of localized fouling and corrosion and result in erroneous oxygen measurements that may drive the combustion process to fire super sub-stoichiometrically. Coupled with reliable and accurate process indications, an online combustion optimizer can improve boiler efficiency and maintain low levels of NOx emissions. By maintaining the pulverizers in good working condition, the grind or coal fineness will be within specifications, reducing any potential performance problems therein. Excessive primary air is an industry problem with many causes. Most coal fired steam generators perform best with a primary air to fuel ratio of 1.8 to 2.0

9. Appendices

- Definition of Terms
    - Boiler Efficiency is the measure of how much heat energy, released by the combustion of coal, is transferred to the water and steam entering the steam generator.
    - Air heater inleakage is the amount of air leaking into the gas side of the air heater as a fraction of the total gas flow entering the heater.
- References and Sources
    - ASME Documents
        - PTC 4.1 – 1964 Steam Generators
        - PTC 4 – 1998 Fired Steam Generators
        - PTC PM – 2010 Performance Monitoring Guidelines for Steam Power Plants
        - PTC 19.3 – 1974 Temperature Measurement
        - PTC 19.2 – 1987 Pressure Measurement
        - PTC 19.5 – 2004 Flow Measurement
    - EPRI Documents
        - 2009 Heat Rate Improvement Conference Proceedings, EPRI Report 1017546, 2009
        - 2007 Heat Rate Improvement Conference Proceedings, EPRI Report 1014799, 2007
        - Guidelines for Fireside Testing in Coal Fired Power Plants, EPRI Report CS-5552, 1998
        - Addendum for Guidelines for Fireside Testing, EPRI Report TR-111663, 1987
- Options to Reduce Uncertainty

  Steam generator efficiency can be a function unit load. For most comparable results, efforts can be taken to ensure the unit load matches the last test run.

Generically, to reduce uncertainty, one can use redundant instruments for each primary data point. Calibrating the instrument prior to the test runs assures one of reduced uncertainty, but is costly. After the test runs, calibrating only those instruments with or having indicated values outside the expect range is another good practice to improve the reliability of the results. If the post-test calibration indicates a problem, the results can be corrected or another test run conducted. Increasing the test duration and amount of data sets collected, as long as the unit's stability is maintained, will reduce the uncertainty.

Traversing the duct work with a portable probe will provide a more representative value for the flue gas temperature. Some stratification is normal and a variation of 20 to 50°F can exist. Increasing the number of data points will improve the reliability of flue gas temperature measurement.

Traversing the duct work with a portable probe will provide a more representative value for the flue gas constituents. Some stratification and variations are normal. Increasing the number of data points will improve the reliability of flue gas sample and final indication measurement.

The chart used to estimate the radiation losses from a steam generator is old and the results may be refined by an indepth analysis. By determining a site specific value for radiation and convection losses from the external surfaces of the steam generator, the overall uncertainty of the results will improve.

By analyzing bottom ash for the unburned carbon, one may account for any difference that exists between the carbon content of the fly ash and the bottom ash. In addition to sampling and analyzing the bottom ash, one must then estimate the resulting distribution of ash between fly ash and bottom ash to complete this calculation.

The equation in section 6 to determine the dry gas losses used a typical value of 0.25 btu/lb°F for the specific heat of the dry flue gas. A more precise specific heat value may be determined with the actual fuel carbon to hydrogen ratio and flue gas temperature.

By accounting for the following heat credits and losses a more accurate value for boiler efficiency can be determined.

A heat credit can be determined for any pre-heating of the air prior to it entering the air heater or FD fans. This is only applicable in those cases when a separate air pre-heating system is in use that does not utilize any waste heat from the combustion process. The equations to determine this credit can be found in ASME PTC 4. The results depend upon the dry gas flow, calculated in the steps above, the nitrogen in the fuel, and the air temperature entering and leaving the pre-heater.

A heat credit can be determined for the moisture in the combustion air in those cases when a separate air pre-heating system is in use. The equations to determine this credit can be found in ASME PTC 4. The results depend upon the dry gas flow, calculated in the steps above, the relative humidity of the air entering the pre-heater, and the air temperature entering and leaving the pre-heater.

A heat loss or credit can be determined to account for the temperature difference between that of the fuel entering the pulverizer and the reference air temperature. This value is typically very small. The equations to determine this credit can be found in ASME PTC 4. The results depend upon the specific heat of the fuel and that temperature difference.

A heat loss can be determined for the moisture in the combustion air entering the boiler. The equations to determine this credit can be found in ASME PTC 4. The results depend upon many of the parameters that constitute the moisture loss calculated in the steps above and the relative humidity of the air entering the steam generator.

A heat loss can be determined for the formation of carbon monoxide (CO) in the combustion process. This loss is only significant in those cases with substantial amounts of CO in the flue gas. The equation for this loss is:

$$Lco = 10{,}160 * C * (CO / (CO + CO_2) / HHV * 100$$

Where:

Lco	Loss due to carbon monoxide, (%)
10,160	A constant representing the heat of formation for CO
C	Weight of carbon burned, lb/lb_{fuel}
CO	Volume of CO in flue gas, %
CO_2	Volume of CO_2 in flue gas, %
HHV	Fuel higher heating value, Btu/lb_{fuel}

A heat loss can be determined to account for the heat lost in the bottom and fly ash. This is applicable only in those cases when the temperature of the ash is significantly above that of the flue gas exiting the steam generator. The equations to determine this credit can be found in ASME PTC 4. The results depend upon the amount of ash in the fuel, its specific heat and temperature upon leaving the steam generator control volume.

- Options to Expedite Results

A steam generator efficiency test is not a simple endeavor. All shortcuts have the potential to greatly increase the uncertainty of the results, up to the point of making the results worthless. Employing a spreadsheet with steam table and psychometric chart call functions to determine interim results from a set of test data ensures consistency and reduces the time from test run to results. Some online performance monitoring systems have internal routines that continuously determine boiler efficiency from process data.

One great simplification that be employed if the fuel flow measurement is accurate is the use of the input-output method. The boiler efficiency as determined by the input-output method is the ratio of the heat input based on fuel flow and HHV to the energy absorbed by the feedwater and steam. The data requirements are greatly reduced compared to the heat loss method. For the input-output method, the following data is needed:

– Fuel flow

– Fuel heating value

– Flow rate, Temperature, and pressure for all streams crossing the control volume…

  - Final feedwater
  - Main steam
  - Hot reheat
  - Cold reheat
  - Attemperation sprays
  - Boiler blowdown flow rate

With the exception of fuel flow, most, if not all of this data is typically available on the unit DCS, historian, or performance monitoring system.

In lieu of continuous or isokinetic sampling, fly ash samples can be taken from ash hoppers. When acquiring an ash sample from a ESP hopper, the carbon content may be lower than that of the ash in the flue gas as ESP do not capture carbon as easily as flyash. The lower than actual carbon content of the ash will provide a falsely high boiler efficiency value for the test run.

11
STEAM JET AIR EJECTORS

Steam Jet Air Ejector (SJAE) Routine Test Guideline

1. Purpose: To determine the performance of a steam jet air ejector
2. Applicability: Steam driven air ejectors in steam power plants
3. Data Requirements
   - Primary
     - Off gas suction pressure
     - Off gas suction temperature
     - Motive steam inlet pressure
     - Motive steam inlet temperature
   - Secondary
     - Temperature rise of coolant passing through the inter-condenser
     - Temperature rise of coolant passing through the after-condenser
     - Temperature of ambient air
     - Pressure of ambient air (barometric pressure)
     - Off-gas flow rate
     - Main condenser pressure (or vacuum)
     - Gross generation
     - Date and time of test
4. Test Pre-requisites
   - Instrument Installation

     The measurements of certain pressures are crucial to the determination of SJAE performance. Complying with the following recommendations for each will reduce uncertainty and provide meaningful and trendable results.

- Pressure Measurements

  The off-gas suction pressure should be measured as close as possible to its inlet to the SJAE. This pressure will be much less than atmospheric, typically less than 5 inches of mercury absolute. Gages with appropriate ranges should be used. Since that pressure is less than atmospheric, ensure the sensor tubing is sloped from the instrument towards the air ejector. No water leg correction should be applied to these measured pressures. If the instrument indicates vacuum, the local atmospheric pressure should be accounted for.

  The motive steam pressure should be measured as close as possible to its inlet to the SJAE. The main steam is usually the source of motive steam and therefore the pressure is high. Appropriate gages and precautions should be employed. For steam pressure measurements of processes operating above atmospheric pressure like this one, a water leg will exist in the sensor tube between the instrument and the process. By always installing those instruments below the process that water leg is continuously maintained and measureable.

  The steam pressure inside the main condenser shell is used for troubleshooting only in this test and may be taken from process data. Follow the same recommendations listed for the off-gas suction pressure measurement.

- Temperature Measurements

  Thermocouples or RTDs (Resistance Temperature Device) should be used in thermowells. If any temperature reading is suspect, the device should be removed from its well, the well cleaned, and the device re-inserted to a depth ensuring contact with the bottom of the well. All thermowells should be immersed to a depth of ¼-½ of the diameter of the process pipe.

  The off-gas suction temperature should be measured as close as possible to its inlet to the SJAE. This pressure may be much close to atmospheric.

  The motive steam temperature should be measured as close as possible to its inlet to the SJAE. The source of motive steam is usually main steam and therefore the temperature is high.

- Instrument Calibration

  The portable test instruments should have been calibrated. More recent calibration improves the accuracy of the results, but is not necessary. Upon receipt of the test data the test engineer should conduct a reasonability check to ensure the values are within an expected range. He or she may substitute data from a backup source, e.g., the process computer, if a primary value is suspect. Calibration of the process data source(s) is not required.

- Stability

  These tests will provide results with less uncertainty if the motive steam pressure can be kept steady, with less than 1% change per hour. For the shut-off test that is the only stability requirement. For the optional troubleshooting portion of the testing, the unit should be at steady state as defined by these parameters:

  – gross generation changes of less than 5% per hour

  – steam pressure changes of less than 3% per hour

  – feedwater or main steam flow changes of less than 3% / hour

  It is recommended to initiate a trend of those parameters via a plant process computer or historian prior to the test.

- Cycle Alignment / Operation

  These tests can be conducted at any load. The SJAE to be tested should be set up as follows:

  – prepare all instruments and data acquisition

  – close and secure the suction connection to prevent any off-gas flow

  – maintain motive steam and cooling water flows at their normal operating settings

  Restore the SJAE to normal operation immediately following the completion of data collection by restoring the connection to off-gas suction.

  Once that test is completed, if the optional testing is to be conducted, keep the SJAE in its normal operating configuration. Ensure the condensate drains from the inter- and after-condensers are routed in their normal configuration and any water legs or loop seals are established to prevent air inleakage or SJAE stalling.

5. Test Methodology

- Data Collection Actions

  The shut-off test quickly determines the steam jet's performance. Additional data collection, an optional test here, can be conducted to better determine the source(s) of any deficiencies.

  SJAE performance tests can be conducted at any generation level, as long as the SJAE may be temporarily removed from service and the motive steam conditions are typical of normal operation. The optional or trouble shooting portion of the testing should be conducted when the unit is at a normal operating load.

  Upon securing the suction flow path and attaining the stability requirements, data acquisition may commence. Data should be collected for a minimum of 10 minutes or the amount of time required for the suction pressure measurement to reach a steady value. A minimum of 3 complete sets of all other primary data should be recorded. Prior to ending the test period, the unit stability trend should be reviewed to ensure steady state was maintained and if possible a trend of the primary test data should also be reviewed to ensure the values and stability are reasonable.

The optional troubleshooting test is conducted while the SJAE is in normal operation. A minimum of 5 complete sets of all data, primary and secondary should be recorded.

- Documentation

The data recorded should be kept in a location and format to permit future accessibility. Immediately following the test period, the complete set of data recorded should be copied and kept separate from the original.

6. Determination of Results

- Data Reduction

All measurements of each parameter recorded during the test run should be averaged. All measured pressures shall be converted to absolute values by incorporating the applicable water leg correction and adding atmospheric pressure to gage readings. Temperatures may only be adjusted for known and documented corrections based on calibration records.

- Methodology and Equations

The key parameter describing SJAE performance is the level of vacuum it can develop. That quantity is measured directly in the shut-off test. The optional testing is focused on troubleshooting and evaluating the portions of the SJAE.

The temperature rise of the cooling water for the inter- and after-condensers is the difference between the respective outlet and inlet temperatures.

  - Motive Steam Flow Rate (optional)

The motive steam is typically a critical flow rate through the inlet nozzle. Since its pressure drop is greater than 55% of its initial value, the steam flows at sonic velocity through the inlet nozzle. The determination of critical flow is simpler than that of sub-critical flow.

In equation form:

Mflow = 1890 * Z * Fa * C * D * D ((Pstmin * RHO) ^ 1/2

Where:

Mflow is the motive steam flow rate (lb/hour)
Z = the compressibility coefficient (-) (0.47 may be used as a default)
C = the nozzle discharge calibration coefficient* (-)
(1 may be used as a default)

D = the diameter of the orifice or nozzle (inches)
Pstmin = the pressure of the motive steam entering the SJAE (psia)
RHO is the specific density of the air motive steam (lbm/ft^3)

7. Interpretation of Results

In the shut-off test, the vacuum developed by the SJAE is the sole parameter of interest.

Less than expected vacuum (a higher absolute pressure) can be the result of:

– Low motive steam pressure

– Low motive steam enthalpy (lower temperature or increased moisture)

– Damaged flow nozzle

– A flow restriction downstream of the SJAE, in its exhaust piping

– Poor loop seal in the inter- or after-condenser drain piping

– Low or no flow from an inter- or after-condenser drain piping

– Tube leak(s) in the inter- or after-condensers

– Leaking suction inlet isolation valves

If the shut-off test provides expected results, but the condenser backpressure and/or the air inleakage flow rate are high, the following problems may exist:

– Poor loop seal in the inter- or after-condenser drain piping

– Air inleakage sources exist in the suction piping to the SJAE

– Unidentified air inleakage sources exist on the condenser shell

– Unidentified air inleakage sources exist in areas that feed to the condenser

In the optional tests:

– If the off-gas flow rate is unsteady, the cooling water temperature may be too high to continuously condense all the steam vapor, causing a chugging flow rate. The cooling water temperature rise would be greater than expected and also unsteady if this condition exists.

– If the cooling water temperature rise is greater than expected or if the condensate flow rates from the inter-or after-condenser are greater than expected, excessive steam vapor may be entrained with the air drawn from the condenser. This is usually caused by a condenser design problem, outside the scope of the SJAE.

8. Post Test Actions

Steam jet air ejectors are often falsely blamed for high air inleakage problems, but are the device that keeps the unit online during those periods of high air inleakage. Their effect on heat rate or capacity is noticed only when the SJAE cannot keep up with the air leaking into the condenser system. The amount of motive steam consumed is a minute fraction of the total main steam for the unit and variations in that steam flow have a negligible effect.

The SJAE play an important support role for the main condenser. The main condenser has the potential to have the largest negative effect on heat rate of any component in a power plant. Causes of abrupt changes in SJAE or condenser performance should be determined and if unexplainable, additional data collection or testing to confirm should be considered.

Flow obstructions and mis-positioned valves cause a majority of the problems for SJAEs. Valve alignment should be one of the first things checked in a post-test evaluation. The two areas to focus on first is the motive steam inlet and the SJAE off-gas discharge.

The SJAE internals can be inspected, but that is usually a last resort. The inlet nozzles and converging/diverging flow sections are usually robustly built, but can be damaged by wet motive steam or entrained particulate matter.

Condensate drain lines and loops seals must be properly designed and maintained to prevent short circuiting of the air between the inter- or after-condenser(s) and the main condenser.

The existence of a proper loop seal on the inter- and after-condenser drain lines can sometimes be observed with thermography. If desired, the drain flow may be measured with an ultrasonic flow meter at a location where the pipe is completely full of water.

9. Appendices

- Definition of Terms
  - Motive steam is sent through the SJAE to create the siphon action or vacuum that draws the air and non-condensibles out of the condenser.
  - Off-gas is the vapor, air, and non-condensibles that are drawn out of the steam space of the condenser.

- References and Sources
  - ASME Documents

    – PTC 24 – 1976 Ejectors

    – PTC 19.5 – 2004 Flow Measurement

    – PTC PM – 2010 Performance Monitoring Guidelines for Steam Power Plants
  - EPRI Documents

    – Condenser Air Inleakage Guideline, EPRI Report TR-112819

  - – NMAC: Condenser Air Removal Equipment Maintenance Guide, EPRI Report 1015058
  - – Air Inleakage and Intrusion Prevention Guidelines, EPRI Report 1014125
  - – Update Report on Condenser Air Inleakage Monitoring, EPRI Report 1015663

- o Other Documents
  - – Heat Exchanger Institute, Standards for Steam Jet Vacuum Systems, 5th Edition, 2000

- Options to Reduce Uncertainty

  In general, calibrating the instruments prior to the test runs assures one of reduced uncertainty, but is costly. After the test runs, calibrating only those instruments with or having indicated values outside the expect range is another good practice to improve the reliability of the results. If the post-test calibration indicates a problem, the results can be corrected or another test run conducted. Increasing the test duration and the number of data sets collected, while maintaining both the SJAE and the unit's stability, will reduce the uncertainty.

  In the optional troubleshooting tests, additional or refined information could assist the analysis of problems. The additional data includes:

  – A measurement of cooling water flow rates. The cooling flow passing through the inter- and/or after-condensers is usually not the entire amount of condensate flow so pump discharge meters will not suffice. These flows may be measured with a strap-on ultrasonic meter.

  – A measurement of motive steam flow rate. This measurement can be made with a nozzle or orifice in the steam piping, but that device will cause an unrecoverable pressure drop that ultimately decreases the SJAE's capacity.

  – A measurement of inter- and/or after-condenser drain flow rates. These flows may be measured with a strap-on ultrasonic meter at a location where the pipe is completely full of water.

  Calculate motive steam flow. This can be done assuming it is a critical flow, occurring when the pressure drop through a restrictive orifice is greater than 55%. The basic equation is in section 6. The detailed flow equations are contained in the ASME and HEI references. The absolute value of this calculated flow can be improved by determining the actual compressibility of the steam, accounting for the nozzle expansion due to temperature, and determining the actual discharge coefficient.

- Options to Expedite Results

  Reducing the number of data sets will provide results quicker with an increase in uncertainty.

If condenser backpressure is at its expected value and the dissolved oxygen in the hotwell is at or below standards, then the air removal system is probably operating as expected and frequent testing is unnecessary.

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