QUICK REFERENCE GUIDE

5th Edition

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Preface

Innovative Combustion Technologies, Inc. (ICT) has prepared this technical reference book for use by its employees, clients and professional associates. The formulas, charts, tables and other reference data are reference information that we use in providing our services of testing, consulting and inspecting large utility boilers. The information contained in this reference guide is believed to be correct. Innovative Combustion Technologies, Inc., or any party or person acting on its behalf, make no warranty, express or implied, with respect to the accuracy or use of any material contained herein. Comments or questions should be directed to:

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Thirteen Prerequisites of Optimum Combustion for Low NOx Burners

1. Furnace exit must be oxidizing, preferably an average of 3.0% with no single point below 2.0%.
2. Individual fuel lines balanced by “Clean Air” test to within ±2% deviation from the mean or better.
3. Fuel lines balanced by “Dirty Air” test, using a Dirty Air Velocity Probe, to ±5% deviation from the mean or better.
4. Fuel line flows balanced to ±10% deviation from the mean or better.
5. Fuel line fineness shall be 75% or more passing a 200 mesh screen. Particles remaining on 50 mesh shall be less than 0.3%.
6. Primary airflow shall be accurately measured & controlled to ±5% accuracy.
7. Overfire air shall be accurately measured & controlled to ±3% accuracy.
8. Primary air/fuel ratio shall be accurately controlled when above minimum line velocity.
9. Fuel line minimum velocities shall be 3,300 fpm or higher (3,300 fpm allows for ± 10% imbalance, 3,000 fpm absolute minimum).
10. Mechanical tolerances of burners and dampers shall be ±1/4” or better.
11. Secondary air distribution to burners should be within ±5% to ±10% deviation from the mean.
12. Fuel feed to the pulverizers should be smooth during load changes and measured and controlled as accurately as possible. Load cell equipped gravimetric feeders are preferred.
13. Fuel feed quality and size should be consistent. Consistent raw coal sizing of feed to pulverizers is a good start.

Procedure for Use of 10” Incline Manometer

1. Remove manometer from carrying case.
2. Rotate stand 90° to support manometer.
3. To open, rotate both valves on top of manometer approximately ½ turn counter-clockwise from closed position.
4. Connect hoses from test probe to valves. The impact or high pressure hose connects to the left valve as you face the manometer, the static or low pressure hose connects to the right valve.
5. Rotate thumbscrew on bottom of manometer until the bubble in the level at the top of the manometer is between the two vertical lines, indicating that the unit is level.
6. Rotate zero-adjustment knob on bottom of manometer until bottom of meniscus is even with the zero mark at the top of the manometer, indicating zero.
7. Leak-check the manometer and tubing by blowing into the high pressure side of the manometer and alternately “pinching,” sealing the high and low pressure tubing.
8. The manometer is now set up, leveled, zeroed and ready to be used in testing.
9. Moving or bumping the manometer can cause it to become unleveled. If during testing the manometer becomes unleveled, simply re-level it according to step 5 above.
10. Reading of the manometer is accomplished by viewing the scale of the manometer at the top of the meniscus.

Calibration Procedures
for ECOM AC Gas Analyzer

1. Check desiccant/filter media.
2. Desiccant/filter media is considered satisfactory if at least half is still pink. If more than half of the desiccant/filter media has turned white then it needs to be replaced.
3. Position water trap in bracket.
4. Plug ECOM in.
5. Turn ECOM on.
6. Ensure screen reads “COAL” or appropriate fuel. If not, use arrows to scroll to the appropriate fuel.
7. Press the button labeled “E.”
8. Screen will display 3 minute countdown for self-calibration cycle.
9. After ECOM has completed 3 minute self-calibration cycle, check flow.
10. Flow is checked by connecting a flowmeter to the bottom port labeled “gas.” Flow is considered satisfactory if flow is between 4 – 6 SCFH (2 – 3 LPM).
11. Press the button labeled “CONTR.”
12. Screen will display “control v1.3” at the top.
13. Place cal magnet on “cal magnet here” area until a beep is heard. It may be necessary to move cal magnet around several times. ECOM will enter calibration mode and calibration screen will be displayed.
14. Verify that the arrow is pointing to the gas being calibrated. *(NOTE: ECOM does not recommend calibrating more than one gas at a time.)*
15. Press button labeled “E.”
16. Hook up gas sample to gas port. (NOTE: It is extremely important that the sensors are not over or under pressurized. The flow of gas must equal the pull of the pump. This can be accomplished by using a gas calibration bag.)

17. If using an oxygen depleted gas, verify that O_2 level drops to ≤ 0.2%. If O_2 does not drop to ≤ 0.2%, check for leaks in water trap connections and tubing. If after eliminating leaks, O_2 still does not drop to ≤ 0.2% return ECOM to vendor to have O_2 cell replaced. **(NOTE: O_2 cannot be calibrated.)**
18. Verify that the gas being calibrated stabilizes.
19. Press enter.
20. Enter concentration of calibration gas.
21. Press “E.” *(NOTE: ECOM must have steady flow of gas up to this point.)*
22. Disconnect gas supply; repeat steps 14 – 21 for other gases.
23. Press “Esc” twice.
24. Verify that O_2 level rises to ≈ 20.9%.
25. Verify that CO level drops below 10 ppm.
26. Calibration complete.

Testing Grids for Ducts and Pipes

Figure 4-1 – Test Grid Layout for Rectangular Ducting

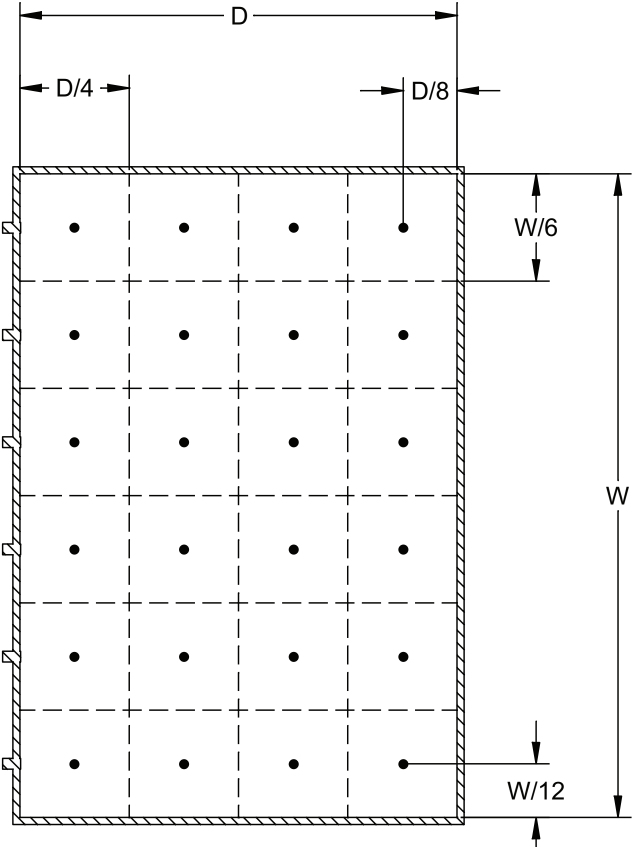


Figure 4-2 – Equal Area Traverse Grid for Circular Ducts and Pipes

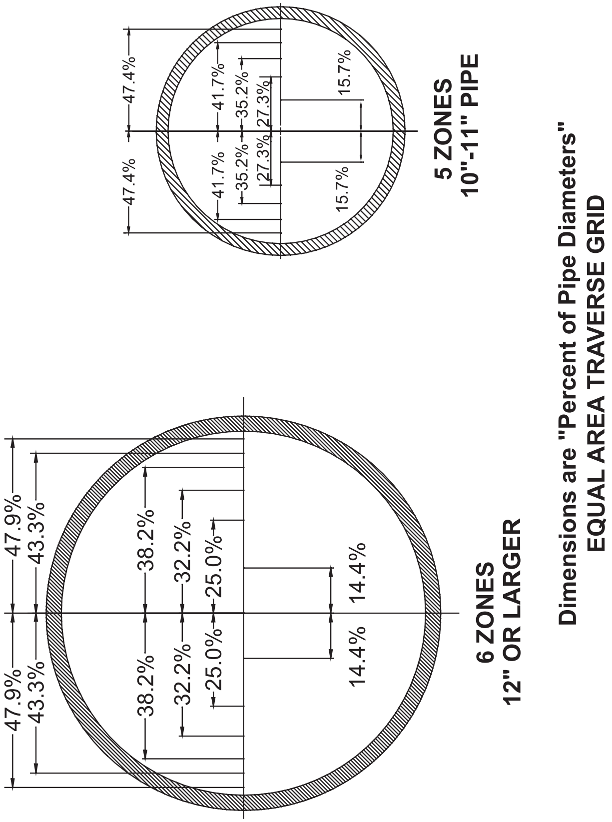


Figure 4-3 – Equal Area Measurements for Standard Pipe

Pipe Size (in)	I.D. (in)	Equal Area Dimension from Pipe Center (8"-11")				
		15.7%	27.3%	35.2%	41.7%	47.4%
8	7.98	1 - 1/4	2 - 3/16	2 -13/16	3 - 5/16	3 -13/16
9	8.94	1 - 3/8	2 - 7/16	3 - 1/8	3 - 3/4	4 - 1/4
10	10.02	1 - 9/16	2 - 3/4	3 - 1/2	4 - 3/16	4 - 3/4
11	11.00	1 - 3/4	3	3 - 7/8	4 - 9/16	5 - 3/16

Pipe Size (in)	I.D. (in)	Equal Area Dimension from Pipe Center (12" or Larger)					
		14.4%	25.0%	32.2%	38.2%	43.3%	47.9%
12	12.00	1 - 3/4	3	3 - 7/8	4 - 9/16	5 - 3/16	5 - 3/4
14	13.25	1 -15/16	3 - 5/16	4 - 1/4	5 - 1/16	5 - 3/4	6 - 3/8
16	15.25	2 - 3/16	3 -13/16	4 -15/16	5 -13/16	6 - 5/8	7 - 5/16
18	17.25	2 - 1/2	4 - 5/16	5 - 9/16	6 - 9/16	7 - 1/2	8 - 1/4
20	19.25	2 - 3/4	4 -13/16	6 - 3/16	7 - 3/8	8 - 5/16	9 - 1/4
22	21.25	3 - 1/16	5 - 5/16	6 -13/16	8 - 1/8	9 - 3/16	10 - 3/16
24	23.25	3 - 3/8	5 -13/16	7 - 1/2	8 - 7/8	10 - 1/16	11 - 1/8
26	25.25	3 - 5/8	6 - 5/16	8 - 1/8	9 - 5/8	10 -15/16	12 - 1/8
28	27.25	3 -15/16	6 -13/16	8 - 3/4	10 - 7/16	11 -13/16	13 - 1/16
30	29.25	4 - 3/16	7 - 5/16	9 - 7/16	11 - 3/16	12 -11/16	14
32	31.25	4 - 1/2	7 -13/16	10 - 1/16	11 -15/16	13 - 9/16	15
34	33.25	4 -13/16	8 - 5/16	10 -11/16	12 -11/16	14 - 3/8	15 -15/16
36	35.25	5 - 1/16	8 -13/16	11 - 3/8	13 - 7/16	15 - 1/4	16 - 7/8
42	41.25	5 -15/16	10 - 5/16	13 - 5/16	15 - 3/4	17 - 7/8	19 - 3/4

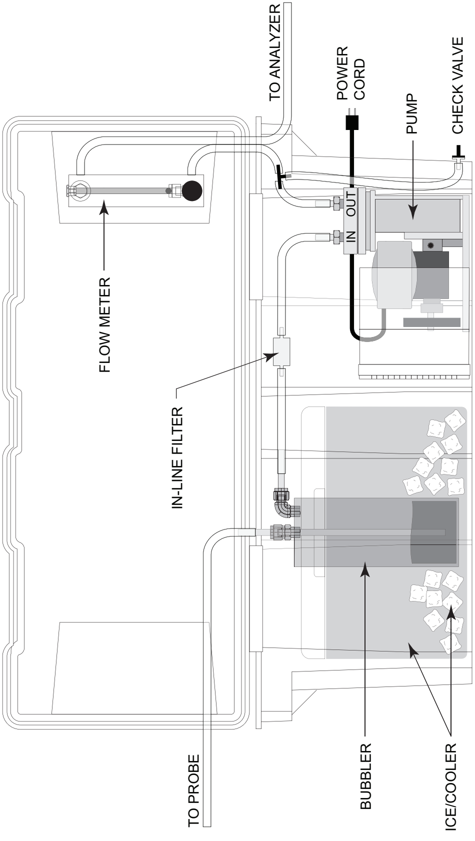
Gas Sampling

Gas sampling and analysis is an extremely important part of ICT's combustion improvement and optimization programs. Flue gas is sampled at various locations throughout the boiler, from the furnace exit using a HVT probe to the I.D. Fan Discharge using a gas sampling static and temperature probe. Gas analysis at the furnace exit provides insight on furnace combustion characteristics, while gas sampling at other locations allows for calculation of area specific air infiltration as well as total unit leakage.

The equipment ICT uses must be highly accurate while still remaining portable. We currently use a portable 5-gas analyzer with an internal pump in conjunction with a gas conditioning system. The analyzer can be configured to measure 4 to 6 gases (O_2, CO, NO, NO_2, SO_2, and C_XH_X). The gas conditioning system is comprised of a booster pump, filter assembly, bubbler/condenser and flow meter. Due to the extremely dirty nature of flue gas on pulverized coal fired units, it is highly recommended that the conditioner be used to filter dust/ash particulate prior to entering the gas analyzer to prolong gas analyzer service intervals. The conditioner also allows for precise metering of flow into the gas analyzer, an important criteria for obtaining accurate data. Another benefit of the ICT gas conditioning system is that it is compatible with all brands of portable gas analyzers.

Testing equipment packages or kits that include the ICT Gas Sampling Conditioner, HVT probes or Gas Sampling Static/Temp probes, as well as the portable gas analyzers are available through ICT. It is believed that the gas analyzers offered by ICT are the best suited for boiler testing. The units are well built, portable, reliable, efficient, light-weight, compact and work quite well in conjunction with the gas conditioning system.

Figure 5-1 – Gas Sampling Conditioner



HVT Probe Procedures

Furnace Exit Traverse

Furnace High Velocity Thermocouple (HVT) traverses are performed to accomplish the following:

1. Quantify furnace exit gas temperatures
2. Ascertain furnace temperature profile
3. Quantify furnace oxygen level
4. Ascertain furnace oxygen profile

The HVT Probe is typically inserted into the furnace at the furnace exit and at the Nose Arch Apex. Temperature at these locations can range between 1500°F and 2800°F (815°C and 1540°C) requiring the HVT Probe to be water-cooled. Water source at the HVT location should be eighty (80) PSI and capable of delivering at least thirty (30) gallons per minute of flow. Figure 6-1 illustrates the HVT Probe design. Figure 6-2 illustrates typical HVT traverse locations on a 500 MW coal fired unit.

Figure 6-1 – HVT Probe

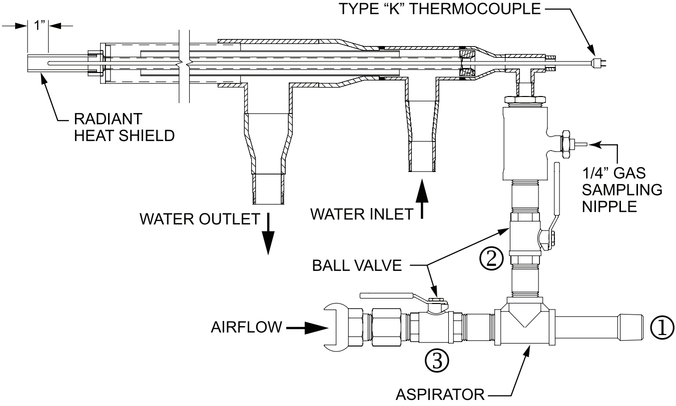
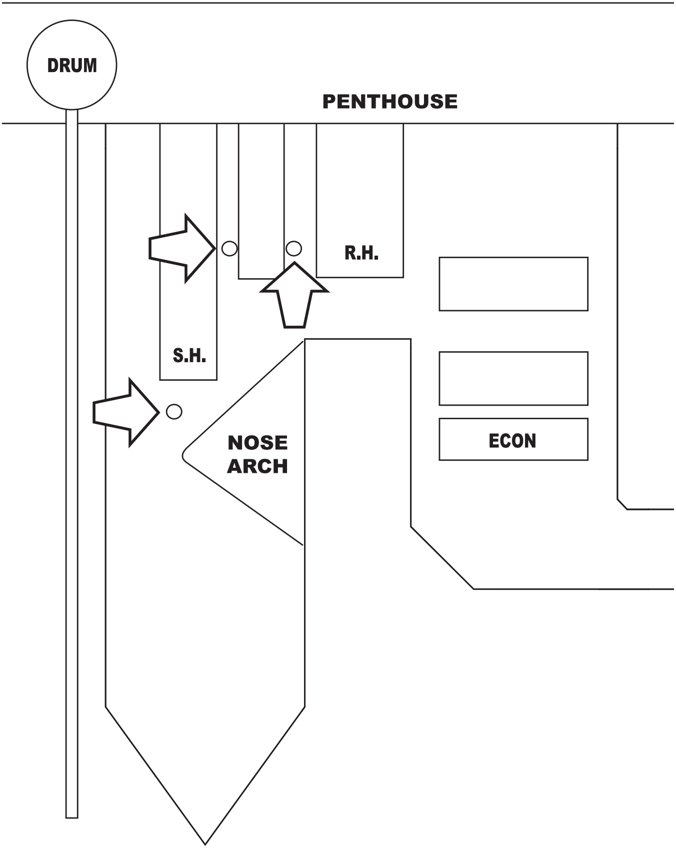


Figure 6-2 – Typical Insertion Points for an HVT Probe



Diagnosis of Combustion Problems by Furnace HVT Traverse

The HVT traverse is, without a doubt, the single most important test in diagnosing combustion related problems. The HVT Probe by design is intended to accurately measure gas temperature, but its greatest importance is the measurement of excess oxygen. Steam generators over ten (10) years old have a common tendency toward high air in-leakage. Air in-leakage through the penthouse, nose arch dead air space, bottom ash hopper dead air spaces, expansion joints and the boiler setting are commonly assigned very low maintenance priority. These items are much more critical to unit performance than most realize. Further complications sometimes include the lowering of excess air to reduce free oxygen and subsequently reduce the formation of thermal NOx to comply with emission levels stipulated by the Clean Air Act. Typically, excess oxygen is controlled by an indication of oxygen level at the economizer exit. High levels of air in-leakage through the areas previously mentioned dilute the flue gas with oxygen prior to its measurement at the economizer exit. It is not uncommon to find total leakage between the furnace exit and the economizer exit in the 20% to 30% range. This results in indicated oxygen of 3% to 4% at the economizer exit and 0% (reducing or sub-stoichiometric atmosphere) at the furnace exit. Temperature is rapidly depressed due to the high density of heating surface following the furnace exit. After the furnace exit, temperature usually falls below the ignition point of carbon very quickly. Without available free oxygen, the carbon fails to combust prior to its quenching below ignition temperature, resulting in high carbon in ash and high carbon monoxide levels.

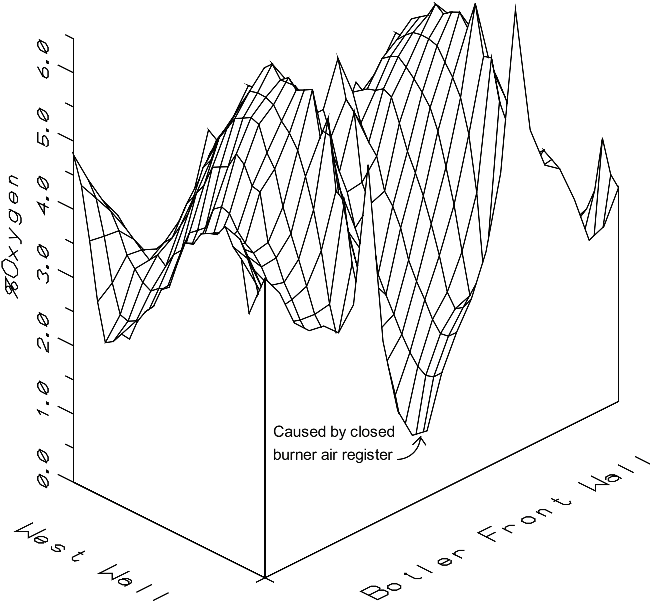
Performing an HVT traverse to determine the presence of oxygen at the furnace exit is a simple, cost effective and efficient method of ascertaining the magnitude of air in-leakage. The absence of an oxidizing atmosphere at the furnace exit is usually the result of high air in-leakage. High air in-leakage will result in increased dry gas loss due to the heat absorption of tramp air which did not pass across the air heaters. If excess air level is raised to obtain an oxidizing atmosphere in the furnace without reducing air in-leakage, higher than design draft losses will be incurred. High air in-leakage will also cause the boiler exit temperature to appear falsely low. The “tempering” effect of the cool ambient air in-leakage will lower indicated boiler exit gas temperature, when in fact, if corrected for leakage, exit gas temperature would be much higher.

Numerous other complications are also the result of this condition, and are as follows:

- Secondary, or delayed combustion, which elevates the combustion zone, reduces waterwall heat absorption and results in high furnace exit gas temperature.
- The resulting high furnace exit gas temperature combined with existence of a reducing atmosphere can lead to the following:
    - Decreased combustion efficiency
    - Overheating of superheat and reheat tubes, which can eventually result in tube failure
    - Combined with the effect of a reducing atmosphere, tube wastage and the subsequent tube thinning can result in future tube failures
    - Aggravation of coal-ash corrosion
    - Increased de-superheating spray flow
    - Serious slagging and fouling of heating surfaces. Reducing ash fusion temperatures are sometimes 250°F (120°C) lower than oxidizing ash fusion temperatures. High exit temperatures combined with lower ash fusion temperatures facilitate a much higher proclivity towards heavy slagging and fouling.
    - Increased cycle losses due to higher soot blowing frequency as a result of increased fouling and slagging of heating surfaces.
    - High boiler exit gas temperature which can lead to accelerated deterioration of air heater heating surface and possible degradation of precipitator performance.
- High leakage can result in reduction in available Induced Draft Fan capacity and subsequent de-rating of unit generation and availability.

Temperature and oxygen profiles obtained by the HVT traverse can also be an indication of imbalances in air and fuel originating in the burner belt zone. Pulverizer fuel imbalances, combustion (secondary) air imbalances, closed air registers, plugged fuel lines, etc. are easily reinforced by the temperature and oxygen profiles determined by an HVT traverse. It is also useful to compare side to side flyash Loss On Ignition (L.O.I.) and slagging tendencies with HVT oxygen profiles. As an example, the figure below illustrates the oxygen profile on a 500 MW wall fired unit. The dip, or cavity, in oxygen level correlates with an air register which was frozen in the closed position.

Figure 6-3 – Oxygen Profile on a 500MW Wall Fired Unit

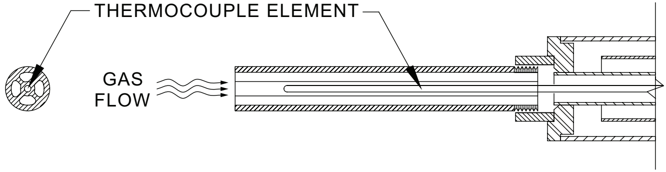


Caused by closed burner air register

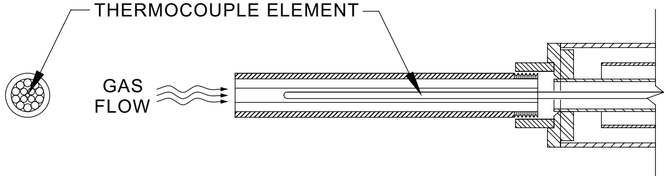
Accurate Determination of Furnace Exit Gas Temperature

Accurate measurement of furnace flue gas temperature requires utilization of a shielded HVT. Bare thermocouples, infrared and other temperature measurement devices will not facilitate accurate measurement of flue gas temperature. New technologies such as acoustic pyrometers, which remain in the early stages of development, have shown some potential, but are not yet consistently reliable or practical. Temperatures measured by bare thermocouples are falsely low due to radiant heat emanated away from the thermocouple. HVTs, also identified by some as “suction pyrometers,” reduce this effect by aspirating flue gas at a high velocity across a shielded thermocouple junction. The multiple shielded thermocouple (MHVT) would eliminate the error between true gas temperature and temperature observed by the HVT. Use of a MHVT in a coal fired furnace is not practical. The small gas lanes of a MHVT radiation shield become fouled with slag, debris and ash in a very short time. A high degree of testing error is caused by high tendency of pluggage of the MHVT radiation shield. Based on experiences over the years, ICT advocates the use of a single shielded HVT. Gas temperatures slightly lower than true gas temperature will be indicated by the single shielded HVT, however, pluggage of the radiation shield and the subsequent testing error is minimized when properly utilized. Figure 6-4 illustrates the single shielded and multiple shielded HVT radiation shields.

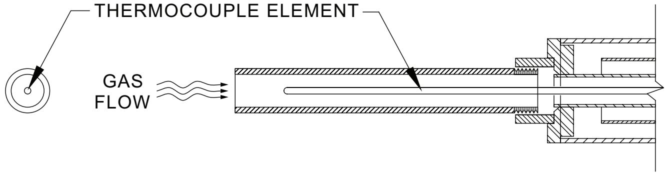
Figure 6-4 – Single Shielded and Multiple Shielded HVT Radiation Shields



TYPE BUREAU OF MINES - MULTIPLE SHIELD HVT RADIATION SHIELD



MULTIPLE SHIELD HVT RADIATION SHIELD

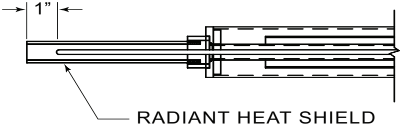


SINGLE HVT RADIATION SHIELD

Performing an HVT Traverse

1. Water supply, water drain and air supply hoses will be required to use the HVT Probe. The number and length of hoses required depends on the location of water sources, drains and air supply. A 1” Ø hose is recommended for both the water supply and drain hose. A water source of eighty (80) PSI and thirty (30) gallon per minute minimum is required. Insufficient water pressure and flow may result in overheating of the HVT Probe during the traverse. Overheating of the probe could damage or destroy the probe and possibly injure personnel using the probe. An air source of eighty (80) PSI is required. Inadequate air pressure will result in lower than optimum aspirating rate which will indicate a lower than actual gas temperature.
2. Hoses should be connected to the probe and arranged in such a manner that easy movement of the probe around all test ports without tension or “kinking” of hoses is facilitated. Care should be taken not to use excessively long water inlet or drain hoses. Excessively long water hoses will result in increased restriction, reducing water flow through the probe.
3. Chicago fittings connecting the water and air hoses to the HVT Probe must be wired or pinned together for safety. Water draining from the probe can be extremely hot at times. If an air or water hose becomes detached during the traverse, injury to test personnel and/ or damage to the HVT Probe may result.
4. Mark the probe at 2’ increments starting from the tip of the radiation shield. Each of these points will be a traverse point where temperature and oxygen are measured.
5. Ensure that the thermocouple is 1” from the tip of the radiation shield. The thermocouple should also be centered and not touching any part of the radiation shield. Figure 6-5 illustrates proper position of thermocouple in relation to the radiation shield.

Figure 6-5 – Correct Installation of HVT Thermocouple



6. Before inserting the probe into the furnace, be confident that the water supply is of adequate pressure, turned on, and that water is flowing through the probe. Do this visually by verifying water is exiting the drain hose. The probe will quickly “melt down” if it is inserted without water flowing through the probe. It is suggested that the drain water flow be verified by filling a five (5) gallon bucket with water flowing from the drain hose exit. Thirty (30) gallons per minute is desired, therefore, a five (5) gallon bucket should be filled in ten (10) seconds.
7. Ensure that the compression fittings on the thermocouple are tight and all other fittings are gas tight. Threaded connections should be sealed with Teflon thread tape and be leak-free.
8. Clear the probe’s sampling line and thermocouple passage. Do this by opening valves (2) and (3), plugging the outlet on the aspirator (1), or using a pipe cap and turning on the air supply to force air through the probe’s sampling line and thermocouple passage. Verify that air is blowing from the tip of radiation shield. (See figure 4-6 for valve designations.) This procedure should never be performed with the probe inserted into the furnace. Performing this procedure with the thermocouple “hot” will accelerate thermocouple deterioration and cause premature thermocouple failure.
9. If aspirating air flow is not adequate, falsely low gas temperatures will be indicated. To ensure sufficient aspirating air flow is obtained, connect a U-tube manometer to the HVT Probe’s ¼” gas sampling nipple, turn on the air supply and begin aspiration. With all valves open and aspirating air on, the U-tube should indicate a suction of 14” w.c. or greater.
10. Typically, temperature measurement is documented traversing “into” the furnace and gas samples are collected as the probe is retracted. Insert the probe into the furnace at the 2’ mark, turn on the air and begin aspirating gas across the thermocouple. Do this by ensuring air is turned on at the source and valves (1), (2) and (3) are open. If using a pipe cap on the aspirator exit, make sure it is removed. Observe the temperature by connecting the thermocouple to a digital thermometer. When the temperature stabilizes, record and move to the next point until the temperature is recorded for all traverse points. Temperatures are sometimes “noisy” and can fluctuate as much as 50°F. This is indicative of secondary combustion and poor mixing in

the burner belt zone. If this occurs, record temperatures on ten (10) second intervals for several cycles and average temperature for that traverse point.

11. Throughout the entire time the HVT Probe is inserted into the furnace, test personnel should keep a bare (un-gloved) hand on the probe to monitor surface temperature. If the probe becomes too hot to touch, remove it from the furnace. Probe overheating is most likely caused by insufficient cooling water flow. Check to ensure water supply is adequate and water supply and drain hoses are not kinked. Verify water is flowing at all times by placing the drain hose in a location that is visible to test personnel conducting the traverse. Test personnel should ensure that hoses do not become “kinked” during the traverse, especially when moving the probe between traverse points.
12. Upon completion of the temperature traverse, turn off air supply and close valves (1), (2) and (3), or replace pipe cap on aspirator exit if not using valve (1). If these valves are not closed, atmospheric oxygen will enter through the aspirator, diluting the gas sample and resulting in falsely high indicated oxygen levels.
13. Prior to beginning an exit gas traverse, the gas analyzer should be calibrated. Standard gas of 2.5% oxygen, 300 PPM carbon monoxide and balance nitrogen should be utilized. If a reducing atmosphere is anticipated or observed during the traverse, additional calibration checks with 0% oxygen, 1000 PPM carbon monoxide gas are recommended. A post-test calibration is also required. Analyzer drift between the pre-test and post-test calibration will be documented on the traverse data sheet.

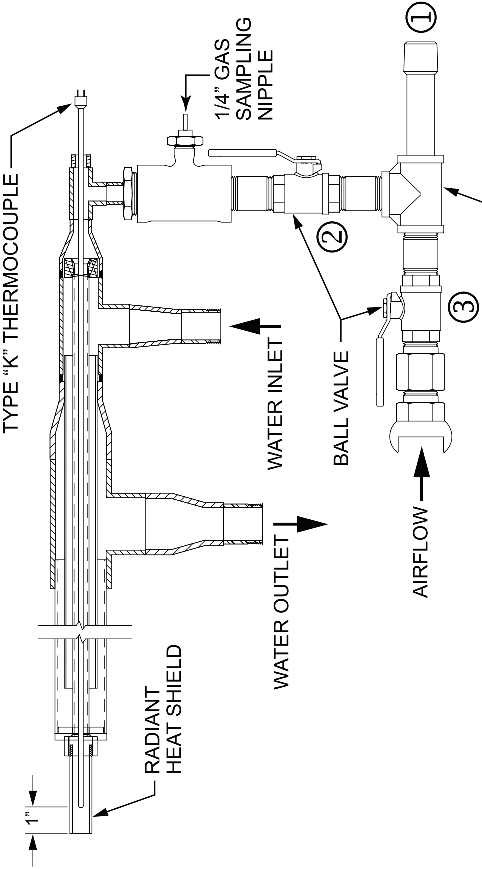
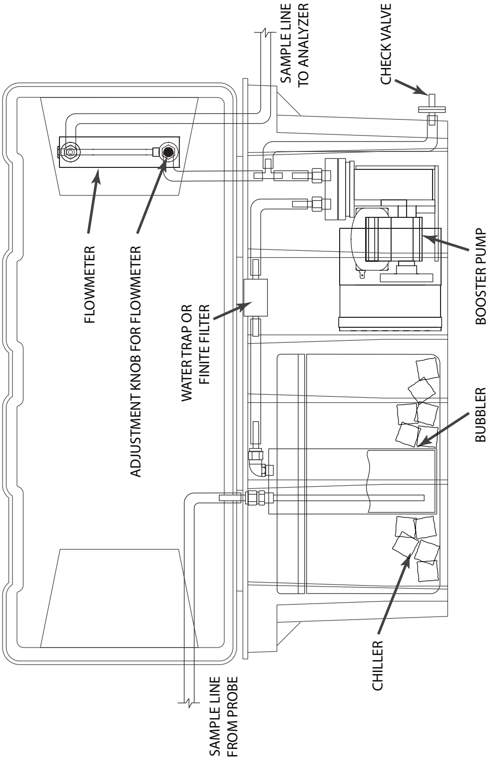


Figure 6-6 – HVT Probe

14. Use of an ICT gas conditioning system (GSC) in conjunction with the HVT Probe and analyzer is preferred. The gas conditioner improves filtration of gas particle constituents, decreases individual sample point collection time and precisely meters flow into the gas analyzer. A schematic of the gas conditioning system is shown in Figure 6-7.

Figure 6-7 – ICT Gas Sampling Conditioner



15. Prior to use, water should be added to the bubbler on the gas conditioner and the fill/drain plug sealed with Teflon thread tape. The bubbler should be filled with 2” to 3” of water or approximately 250 to 300 ml. The bubbler should be placed in the chiller and ice placed around it. Once temperature measurement has been completed and the valves closed, connect the sample line (from probe) to the bubbler inlet. Establish power to the gas conditioner and connect the conditioner discharge (outlet of flow meter) to the gas analyzer. Adjust the flow meter needle valve as necessary to provide the recommended flow.

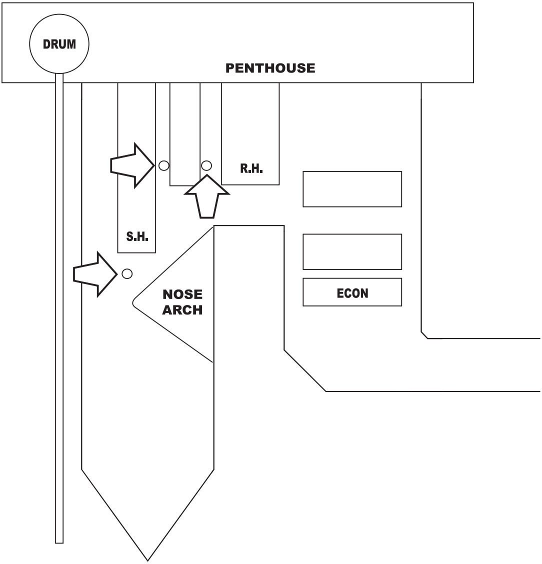
    Note: The gas conditioner should never be connected to the HVT Probe while the aspirating air valves are open. The suction created by the aspiration effect could pull the water from the bubbler and possibly damage the conditioner and analyzer diaphragm pumps.

16. Connect the oxygen analyzer to the probe’s ¼” nipple using tubing.
17. Leave the probe fully inserted into the furnace while the analyzer is pumping a sample for approximately (2-3) minutes or until oxygen indication stabilizes. If an ECOM analyzer is used, it is critical that flow into the analyzer be monitored and maintained at (4-6) SCFH or (2-3) LPM. Record oxygen, carbon monoxide and any other desired gas constituent. Then withdraw 2’ to the next traverse point and repeat the process. If the oxygen reading tends to vary more than 0.5%, it is suggested that the readings be recorded on (30) second intervals and averaged.
18. If at any time throughout the test the probe appears to be plugged, it should be removed from the furnace and back blown. This is accomplished by repeating step No. 8. Once finished, reinsert the probe and resume testing. Make sure the oxygen analyzer shows a steady reading before moving to the next point.
19. At the end of each day of use, the HVT Probe should be flushed with water (thermocouple/gas lane) to remove any deposits of corrosive gases which may have condensed in the center tube. In addition, the chiller and bubbler should be emptied and flushed out after use.

Furnace Exit Traverse

Analysis of flue gas at the horizontal furnace exit (nose arch apex) provides the most accurate indication of combustion conditions, prior to any mixing of the gases that may take place in the convection backpass. This data is gathered with the use of an HVT (High Velocity Thermocouple) Probe. The HVT Probe is a water cooled, stainless steel probe used for measuring flue gas temperature and collecting gas samples at the furnace exit. The sketch below illustrates typical locations for insertion of a HVT Probe.

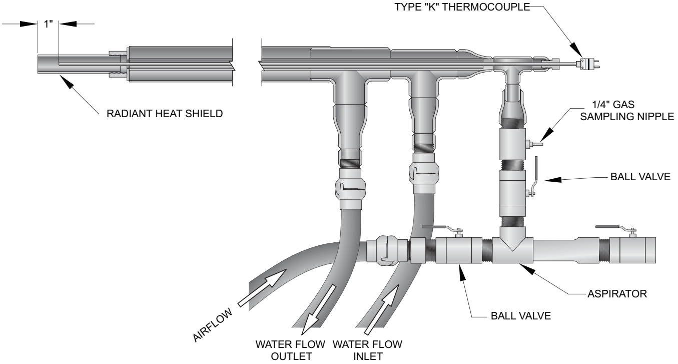
Figure 7-1 – Typical Locations for Insertion of a HVT Probe



HVT Probe

Using existing furnace observation ports, the 2" Ø probe can be used to develop a profile of furnace exit combustion characteristics, namely excess oxygen level and flue gas temperature. ICT has found this to be the quickest and most efficient means of documenting the overall combustion process. The sketch below illustrates an HVT Probe.

Figure 7-2 – HVT Probe



With sufficient water flow (approximately 25 - 30 gal/min. @ a minimum of 80 PSIG) and special thermocouples, the probe is capable of operating in environments of up to 2700°F. Normally, the probe is equipped with a type "K" thermocouple rated to slightly less than 2500 °F. This arrangement is usually quite suitable for units designed with furnace exit gas temperatures in the range of 2200°F. HVT Probes can be manufactured in any length from 4' to 20', however, most applications can be addressed with a standard 12' or 20' long probe.

HVT Troubleshooting

Problem #1

Low Flow: The ECOM AC built-in pump pulls less than two (2) LPM (4 SCFH).

Recommended Action

Check external hoses for holes or pinching. Check pressure drop across the ECOM heater/water trap. Drop should be approximately 0.5 LPM (1 SCFH). Remove hoses from the scrubber canister and gently blow through it to ensure that there is no restriction to flow.

Pump Cleaning: If these procedures are not effective in increasing flow, it will be necessary to access the ECOM AC pump. Remove the screws securing the top panel (screws located around top periphery). Pump is located near the center of the unit. Prior to removing the hoses, label them and look for signs of restriction. Remove the hoses and check the flow through the pump only. The flow should be at least three (3) LPM (6 SCFH). If it is less than this, the pump needs to be cleaned. Once hoses have been disconnected, use a No. 1 Phillips screwdriver to remove the four (4) screws securing the pump diaphragm. Remove all pieces above the pump piston assembly, being careful to retain the proper position and orientation of each piece. Each individual piece should be cleaned using soap and water. Be sure to clear both “flapper” valves (rubber, hour glass-shaped valves secured by metal rings) thoroughly.

Reassemble the diaphragm pieces and place them on the pump base. Rotate the assembly side to side to ensure that the pump piston seats properly. Replace the four (4) screws. Retest the flow. If flow is still low, the pump is either still dirty or there is an internal leak in the pump. Disassemble, clean, reassemble and test again. Once the pump is capable of generating adequate flow, reattach all hoses and replace the analyzer top. The unit should be ready for use.

Problem #2

Flow (by gas conditioner flow meter indications) is unusually steady, O_2 reading extremely consistent and somewhat high, and the tubing “pops” when removed from the probe. Any one of the above conditions could signal a plugged HVT Probe.

Recommended Action

Remove the probe from the furnace and allow it to cool for (2-3) minutes. Try to blow air through the probe by closing valve (1) or using a pipe cap on the aspirator exit and opening valves (2) and (3). If this is unsuccessful, carefully remove the radiation shield. Before removing, check to ensure that the thermocouple has not bonded to the shield. Obstruction of the probe usually occurs in the small opening at the tip of the probe. Use a pick or screwdriver to remove any buildup and clean using air pressure. Replace the radiation shield.

Problem #3

High O_2 readings could be indicative of actual conditions or could be the result of a leak or insufficient flow into the analyzer.

Recommended Action

First, verify that the probe is not plugged. If it is, follow the steps as outlined in Problem #2 to correct. If the probe is clear, check to see if the analyzer is pulling sufficient flow. If not, look for leaks and/or restrictions and clear the pump as described in Problem #1. A quick method to check for leaks across the ICT gas conditioner is to hook the sample line from the probe directly to the gas analyzer and compare the O_2 readings with and without the gas conditioner for several points. If there is a noticeable, consistent difference, check all compression fittings. If the leak persists, a compression/vacuum tester will be required to pinpoint the leak.

Problem #4

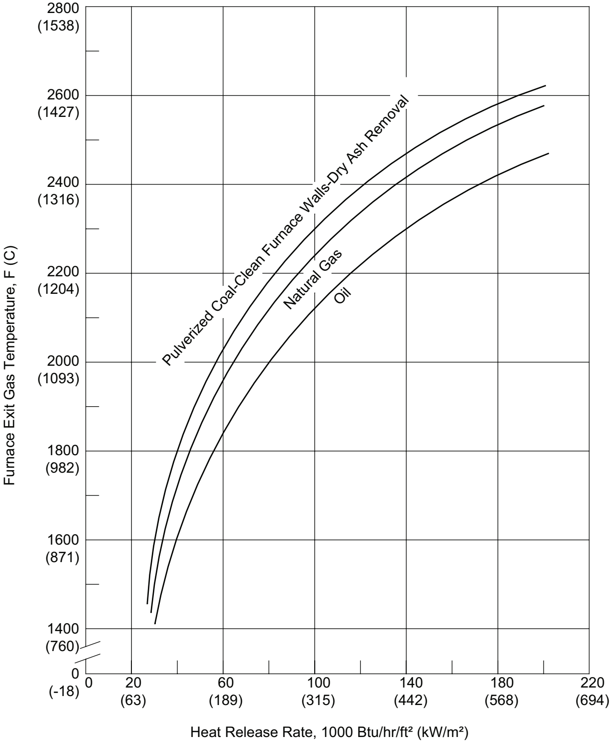
Bubbler overflows into water trap: This condition is indicative of a possible leak or excessive condensation layout in the probe/sample lines.

Recommended Action

To check for a probe leak, initiate cooling water flow and place the probe on an inclined surface in order to view any water exiting the tip. Some occasional escape of water is to be expected, however, a constant flow would indicate a leak. More in-depth leak checking requires pressurization of the probe.

In places with extremely cool water supplies, increased condensation and more rapid filling of the bubbler is to be expected. In such cases, dump/change the bubbler water more frequently.

Figure 8-1 – Approximate Relationships of Furnance Exit Gas Temperature to Heat Release Rate for Various Fuels



Airflow Measurement

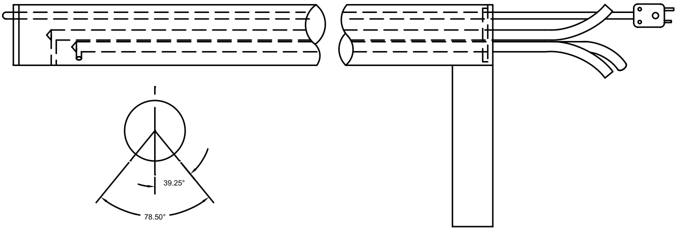
Fecheimer Probe

Proper distribution of combustion airflow is perhaps the single most important variable in combustion optimization. In order to quantify combustion airflow, ICT employs the use of several types of probes to measure airflow at various points throughout the boiler system.

The Fecheimer Probe is an industry accepted three hole probe capable of determining the direction of maximum velocity head. When combined with a protractor, an angular component of the velocity head placed parallel to the ductwork being traversed, velocity can be calculated. This capability is well suited for such applications as fan acceptance tests or when test locations are located near bends or restrictions.

The Fecheimer Probe is designed with the impact hole slightly forward of the two null balance static holes. The static holes are located 39¼° to each side of the centerline of the impact hole. When the static holes are connected to both sides of a U-tube manometer, or similar substitution, the user is able to rotate the probe until a "null" balance is achieved. At this point, the probe is positioned directly in-line with the flow.

Figure 9-1 – Fecheimer Probe

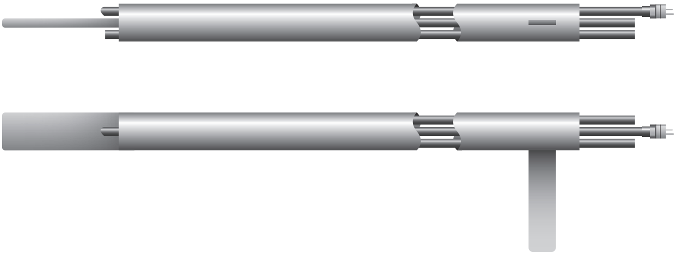


Forward Reverse Probe

The most commonly utilized air flow measuring probe is the billeted head Forward-Reverse Pitot Tube. The probe is similar in design to that of a Stauschiebe Probe. However, instead of having exposed, opposing tubes exiting the probe head, the Forward-Reverse Probe is designed with a machined billeted head that is far more resistant to damage than the Stauschiebe Probe. As with all airflow measurement probes, the forward-reverse is calibrated in a wind tunnel against an accepted bullet-nosed pitot tube with a “K-factor” of 1.0.

The Forward-Reverse Probe is generally used in areas where the test taps have been located in straight runs of ductwork and the flow can be assumed to be parallel to the duct. Typical applications include the measurement of “total” secondary air to the boiler (as measured in venturies or between airfoils), measurement of secondary air at the windbox and primary airflow to the mills.

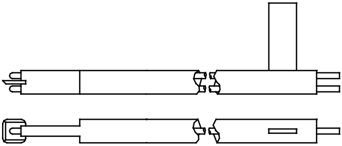
Figure 9-2 – Forward Reverse Probe



Dirty Air Probe

A specialty of ICT is the ability to measure the airflow in individual burner lines while the mill is "in service." This airflow, also known as "dirty" airflow, is useful in determining mill in-leakage values on suction mills, verifying mill heat balance calculations, determining the level of mill performance (airflow balance, minimum line velocity, etc.) and most importantly, establishing the average velocity necessary for collecting an isokinetic coal sample from each individual fuel line, which will be later discussed. The figure below shows a typical Dirty Air Probe.

Figure 9-3 – Dirty Air Probe



Pitot Tube

The last type of airflow measuring probe regularly used by ICT is the widely recognized "L-Shaped" Pitot Tube. This probe is used whenever possible. Typically, this probe is used mainly during "clean air" tests on the individual burner lines to determine airflow balance in the absence of fuel. The probe usually measures 5/16" in diameter. The pitot tube is available in various lengths from 12" to 8' and longer. It is also available in a heavy wall version. The figure below illustrates an L-Shaped Pitot Tube.

Figure 9-4 – Pitot Tube

Procedure for Using a Fecheimer Probe for Air Flow Measurement

Necessary Test Equipment

Quantity	Description
1	Fecheimer Probe of sufficient length.
2	10” Incline Manometers. One manometer will be connected across the differential pressure transmitter for local pressure measurement. The second manometer will be used to record velocity head measurements off the probe.
1	Sufficient length of triple and double strand flexible tubing to use with incline manometers.
2	U-tube Manometers (60” slack tube and 24”). One U-tube to be used for static pressure measurement. The second U-tube will be a “null” balance to help position the probe directly into the air flow stream.
1	Temperature measurement assembly including: one type “K” chrome-alumel thermocouple of sufficient length integrated into the probe, one type “K” lead wire of sufficient length, and one digital thermometer.
1	One pair of hot gloves.
1	One angle finder to be used with the probe.

Assembly of the Test Equipment

The first step is to setup the incline and U-tube manometers, taking special care to ensure that all valves are open, the inclines are leveled and everything is properly zeroed. Connect one incline manometer across the differential pressure transmitter using the double strand of tubing. The “high” side of the transmitter should correspond with the “high” side of the manometer. When valving the incline “in”, it may be necessary to pinch both sides of the tubing and release them simultaneously so that the manometer oil is not blown out.

The triple strand of heavy wall flexible tubing should then be connected to the remaining incline and Fecheimer Probe illustrated in figure 10-1. Attach (1) strand of the tubing and label it No. 1 to the “high” side of the manometer. Label and attach No. 2 to the “low” side of the manometer and label and attach No. 3 to one side of the 60” slack tube manometer. The opposite ends of the triple strand should be connected to the probe. Tubing labeled No. 1 should be connected to the sensing line closest to the thermocouple. Tubing labeled No. 2 and No. 3 should be connected to the remaining SS sensing lines. (Note: It does not matter which is which, as both are low pressure sensing taps.)

Connect the double strand of tubing that is 3-way connected off of the triple strand to the 24” U-tube manometer. This is the “null” balance U-tube. Once again, it does not matter which side is connected where.

Traverse points on the probe are to be marked according to PTC 38 for rectangular ducts if possible. For airflow measurement, ICT typically tries to achieve a minimum of at least one traverse point for every 1 - 2 ft² of duct area. Once this is complete, the probe is ready for use.

Figure 10-1 – Fecheimer Probe

Testing

The first step in testing is to establish steady state conditions for the unit. All soot blowing should be completed prior to commencement of the test. The unit will need to remain steady for the duration of the test.

Insert the probe into the duct and position it on the mark providing the deepest depth. It may be necessary to “pinch” both the “high” and “low” pressure tubing leading to the manometer when inserting or removing the probe from a test port. Extremely high static pressures can cause oil to be blown out of the 24” manometer if not careful. By starting at the deepest mark, the probe has some time to cool as it is worked out of the duct and is generally easier to handle when moving between ports. Be sure to use proper safety equipment and hand protection with an appropriate level of protection for the temperature of the air or gas being measured.

Once the probe is positioned at the first mark, rotate the probe slowly until the “null” U-tube is balanced. This balance is usually no more than 15 - 20° off the centerline of the duct. Take care to make sure that the impact hole, “high” pressure hole, is positioned into the flow as the probe is inserted. An erroneous “null” balance can be achieved with the probe head turned directly away from the flow.

Once the “null” position is established and held, record the velocity head reading off of the incline, the temperature from the digital thermometer, the angle of the probe with relation to the duct and the static pressure off of the slack tube “U-tube” manometer. Move to the next point. Once all points for the test port have been recorded, it is necessary to move to the next port.

Be sure to record the local differential pressure across the transmitter at least three (3) times during the test (at the beginning of test, during the test and at the end of the test). Average these values for use in calculating the measurement device “K factor”.

Calculations used in conjunction with the Fecheimer Probe can be found in Section A of the Calculations and Formulae located in the back of the book.

Clean Air Balancing of Fuel Lines

The "clean air" method of fuel line balancing is the first step in balancing fuel to individual burners. Balancing system resistance of fuel lines on clean air is the first phase of a comprehensive fuel and air balancing program. It is important to remember that clean air balancing is an important factor in optimizing pulverizer fuel and air balance, however, it is only one of many critical parameters which must be addressed. Optimum fuel balance is achieved through a combined effort aimed at improving pulverizer grinding efficiency (improved fineness), riffle distributor condition (where applicable), and classifier timing and condition.

Purpose of Performing a Clean Air Test

Clean air balancing is performed to:

- Establish similar system resistance for each coal line on a balanced air flow basis.
- Provide a correlation between fuel line dirty air and clean air velocities.
- Be an integral part of fuel line air to fuel ratio balancing, which incorporates air as well as fuel balancing.
- Ensure the minimum fuel line velocity is maintained after optimization of primary air flow to improve flame stability at lower loads and reduce fuel line stoppages.

The clean air velocity traverse is very similar to a dirty air traverse. The difference between these two tests is the absence of coal flow during a clean air test. This permits the use of an industry accepted standard 90° Pitot instead of a Dirty Air Probe.

Parameters

A clean air test should consist of two (2) crews working simultaneously on the same pulverizer, starting at opposite sides or corners of the boiler and each crew performing a complete clean air test. This will facilitate collection of two (2) independent sets of data.

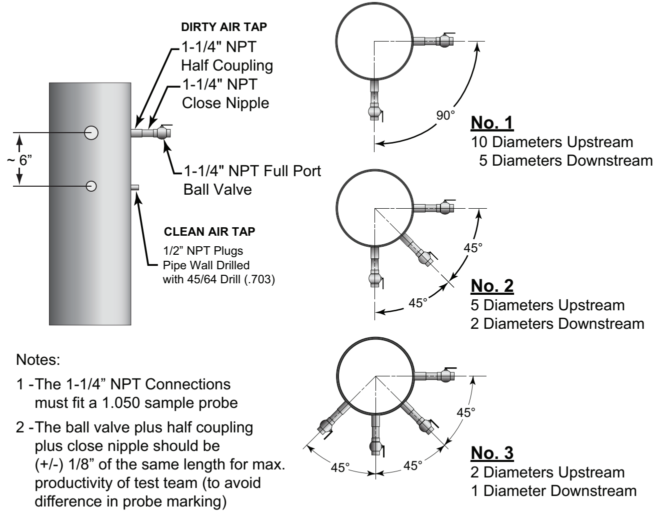
Collected test data should be reduced immediately following completion of the test. Reduction of clean air data will consist of calculation of velocity, mass flow and deviation from the mean velocity for each individual fuel line. The reduced data from each separate team will be compared. Percent deviation between the results of the two separate sets of data should be no more than ±1%. If ±1% repeatability is not obtained, the test is considered invalid and should be repeated. This is required to ensure repeatability, accuracy and validity of the test conditions. If repeatability is not achieved, one or more of the following factors may be the cause:

- Human error.
- Leaking and/or plugged Pitot tube, sensing lines, tubing or manometer.
- Fluctuations in pulverizer air flow or temperature.

Performing a Clean Air Test

1. Install coal line test taps to facilitate insertion of Pitot tubes. Ideally, coal line test taps should be located in a vertical run of piping between five (5) and ten (10) diameters downstream or upstream of the nearest obstruction (i.e. elbow, orifice plate, flange, isolation value, etc.) to ensure a fully developed velocity profile. Two test ports, 90° apart, per pipe are required. Clean air test ports are installed by drilling and tapping ½" N.P.T. holes through the pipe wall and inserting a threaded pipe plug. Figure 11-1 illustrates the correct installation of clean and dirty air test taps based on the available location for drilling and tapping.
2. Traverse points on the Pitot tube are marked on an equal area grid in accordance to ASME Performance Test Code for traversing circular ducts. This ASME standard, for pipes with 10" or larger diameters is illustrated in figure 4-2 and the back cover of this booklet. ICT recommends using a paint pen or permanent marker to make these traverse points on the Pitot tube.

Figure 11-1 – Clean and Dirty Air Measuring Connections



Notes:

1 - The 1-1/4” NPT Connections must fit a 1.050 sample probe

2 - The ball valve plus half coupling plus close nipple should be (+/-) 1/8” of the same length for max. productivity of test team (to avoid difference in probe marking)

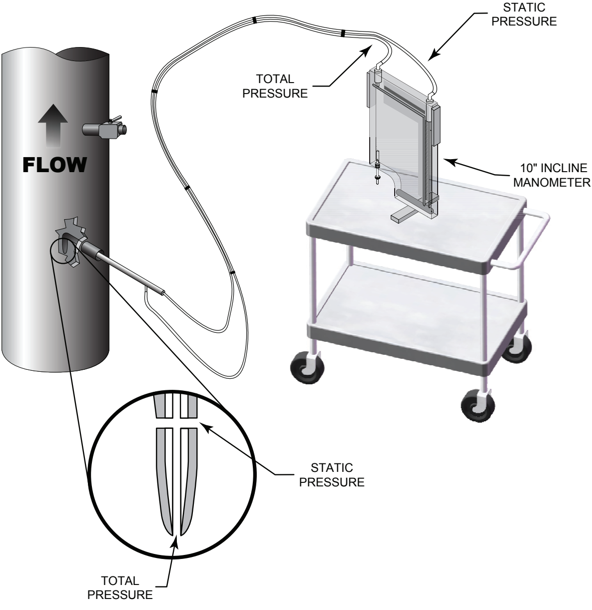
3. Two equal sections of tubing are cut to desired length. The tubing is then taped or bound together and one tube is marked on both ends to identify it as the “high–pressure” or “total” line. The remaining tube, which is unmarked, is identified as the “low–pressure” or “static” line.

4. A 10” inclined-vertical manometer is set up on a level and stable location as discussed on page 8 of this manual. Tubing is attached to the correct taps on the Pitot tube and the manometer. Figure 11-2 illustrates a Pitot tube properly connected to an incline manometer.

5. The following data should be recorded for each test:
    - Coal pipe designation
    - Individual velocity heads for each traverse point [typically (24) points - (12) per port]
    - Temperature and static pressure for each pipe

   (An example data sheet for recording clean air traverse data is illustrated in Figure 11-3.)
6. Prior to inserting the Pitot tube, ensure the incline manometer is level and zeroed.

Figure 11-2 – Pilot Tube and Manometer Setup



7. Insert the Pitot tube to the first mark with the pointer directed parallel into the flow and observe. Allow the incline manometer indication to stabilize, then record and move to the next point. Repeat this process for all (12) traverse points on both ports.
8. After traversing both ports, a static pressure is measured by inserting a ¼" Ø stainless steel tube into the fuel line. Static pressure will be measured using a U-tube manometer connected to the stainless tube by a single piece of tubing.
9. Following static pressure, temperature will be measured by inserting a thermocouple into the fuel line.
10. Calculate velocity in each fuel line and ascertain balance. Balance should be expressed as deviation from the mean velocity of all pipes. The equations utilized to reduce clean air traverse data can be found in Section A of the Calculations and Formulae located in the back of the book.
11. After determination of fuel line clean air balance, the installation of orifices is evaluated. One of the primary reasons for the dual-team approach is to facilitate a high confidence level in the data. Highly accurate, repeatable data is of utmost importance to make informed decisions on changing orifices. Desired clean air balance of ±2% requires data between the two separate crews to be within ±1% before making any orifice changes.
12. Fuel lines are orificed by an iterative process utilizing trial orifices fabricated from 10-gauge carbon steel. After optimum orifice configuration is determined, permanent 304-stainless steel orifices are installed.

Figure 11-3 – Sampling Data Sheet for Recording Clean Air Traverse

Innovative Combustion Technologies, Inc.
Coal Pipe I.D. (inches): __________
Coal Pipe Area (Ft^2): __________
Test Personnel: ______________________

Barometric Pressure ("Hg): __________
Pulverizer: __________
Date: __________
Test No.: __________

Burner No:	Pipe 1	
Point	Port 1	Port 2
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		

K Factor		
Sqrt Vh		"w.c.
Temperature		°F
Static		"w.c.
Density		Lbs./Ft^3
Velocity		Fpm
Airflow		Lbs./Hr.

Burner No:	Pipe 2	
Point	Port 1	Port 2
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		

K Factor		
Sqrt Vh		"w.c.
Temperature		°F
Static		"w.c.
Density		Lbs./Ft^3
Velocity		Fpm
Airflow		Lbs./Hr.

Burner No:	Pipe 3	
Point	Port 1	Port 2
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		

K Factor		
Sqrt Vh		"w.c.
Temperature		°F
Static		"w.c.
Density		Lbs./Ft^3
Velocity		Fpm
Airflow		Lbs./Hr.

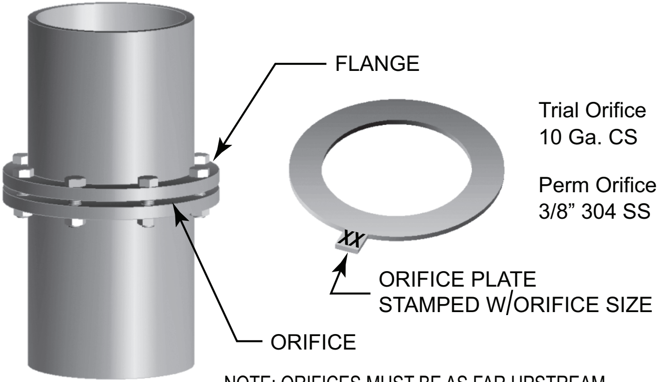
Burner No:	Pipe 4	
Point	Port 1	Port 2
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		

K Factor		
Sqrt Vh		"w.c.
Temperature		°F
Static		"w.c.
Density		Lbs./Ft^3
Velocity		Fpm
Airflow		Lbs./Hr.

Total Dirty Airflow	Lbs.Hr
Average Pipe Temperature	°F
Average Pipe Velocity	Fpm

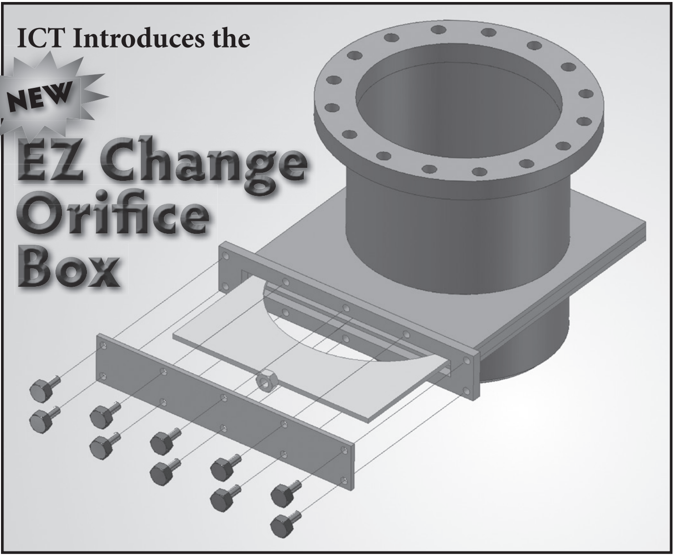
Clean Air Balance (% Velocity Deviation)			
PIPE 1	PIPE 2	PIPE 3	PIPE 4

Figure 11-4 – Flange and Orifice Plate



NOTE: ORIFICES MUST BE AS FAR UPSTREAM OR DOWNSTREAM OF TEST TAPS AS POSSIBLE. >10 PIPE DIAMETERS PREFERED

Figure 11-5 – EZ Change Orifice Box



- Quickly pays for itself by reducing time and expense of performing burner line clean air balancing using conventional methods. Orifice plates can be changed in minutes instead of hours.
- A superior alternative to the “flange-inserted” orifice plates. Eliminates the need for labor intensive orifice changes that require the burner lines to be broken loose. Does not require the complete LOTO (lock-out, tag out) of the pulverizer.
- Dual purpose, as solid blanks can also be fabricated to isolate individual burner lines. This is mandatory for those plants that do not already have independent burner isolation gates.
- Allows personnel to quickly verify orifice wear during scheduled outages. High wear steel will provide superior wear prevention, thus requiring less frequent orifice replacements.

Isokinetic Coal Sampling Equipment

Many OEM boiler designs of the 1960's were based on the single stage combustion theory and were designed with a very conservative furnace. Very little emphasis was placed on mill performance since it was assumed that the turbulent nature of the furnace would be sufficient to adequately mix and combust the coal particles. However, with passage of the Clean Air Act of 1992, many boilers now require strict attention to mill performance in order to meet nitrous oxide, sulfurous oxide and particulate emissions levels while still maintaining acceptable combustion efficiency. As a result, a higher degree of precision in delivery of fuel and air to the furnace is required.

In order to quantify mill performance, ICT uses several pieces of equipment that allows the measurement of individual burner line airflows and extraction of isokinetic coal samples from each pipe. With this data, we are able to accomplish the following:

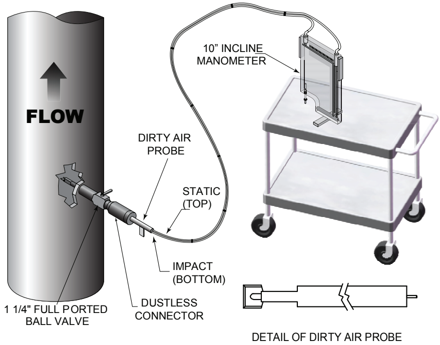
- Quantify pulverizer air to fuel ratio
- Ascertain relative pipe to pipe fuel balance
- Quantify individual fuel line air to fuel ratios
- Quantify individual fuel line velocity and air flow
- Ascertain pipe to pipe air flow balance
- Quantify fuel line temperature and static pressure
- Collect a representative fuel sample from each pipe for coal fineness analysis

Dirty Air Probe

The first piece of equipment used in the isokinetic coal sampling process is a Dirty Air Probe. The Dirty Air Probe, discussed earlier in this guide, is a field proven device which allows measurement of air flow in a dust-laden environment with minimum probe stoppage. The probe measures velocity head differentials across a deflector plate that is positioned between the "high" and "low" pressure taps. Ideally, measurements are taken on a minimum of two axes, 90° apart on a vertical run of pipe. More traverse planes are utilized when test planes are in close proximity to bends or elbows. Traverse points are then selected and marked on the probe in an equal area grid in accordance with the ASME Performance Test Code for traversing circular ducts.

The Dirty Air Probe is used to determine an average velocity for each burner line. With this velocity known, the next step is the collection of an isokinetic coal sample using an air/fuel sampler. The figure below illustrates a typical dirty air traverse setup.

Figure 12-1 – Typical Dirty Air Traverse Setup



Static and Temperature Probe

Once the velocity heads are recorded, a temperature and static pressure (necessary for air mass flow calculation) is documented with the use of a Static and Temperature Probe. The probe combines a type "K" thermocouple for temperature measurement with a ¼" sensing line for static pressure measurement. The Static andTemperature Probe is shown in the following illustration.

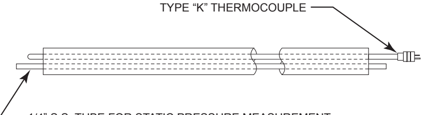
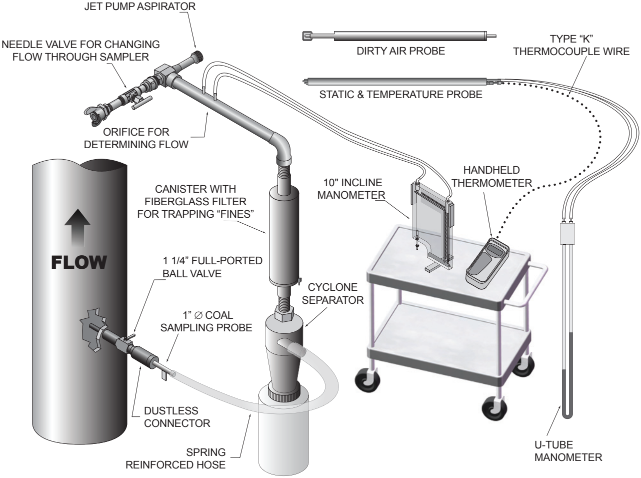


Figure 12-2 – Static and Temperature Probe

Coal Sampler

To collect a representative coal sample, the velocity entering the air/fuel sampler tip must equal the velocity of the airflow in the burner line. An "in-line" orifice with a known area is used to monitor the total flow through the sampler system to ensure that the sampler tip velocities remain at a constant isokinetic rate. An aspirator assembly provides suction to control the flow. The illustration below shows the air/fuel sampler arrangement.

Figure 12-3 – Air/ Fuel Sampler Arrangement



The coal sampling probe is marked in the same manner as the Dirty Air Probe and each traverse point is sampled an equal amount of time. Usually, the total sample time for the entire pipe is four (4) min.

The primary air/coal mixture is collected by the sampler tip and carried through a reinforced, flexible PVC hose to a Cyclone Separator. There, the cyclone separates the coal particles from the air. Fine particles entrained in the airflow leaving the cyclone are captured by the filter canister mounted above the cyclone. Clean air then passes through the orifice assembly and is discharged.

Isokinetic Coal Sampling

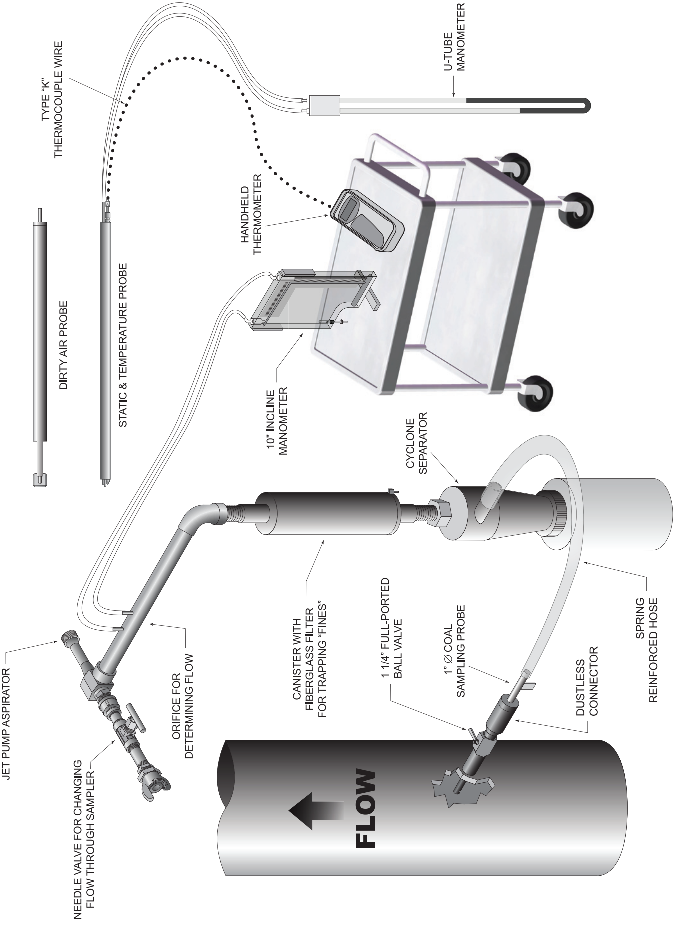
Isokinetic coal sampling is performed to accomplish the following:

1. Ascertain relative pipe to pipe fuel balance.
2. Quantify individual fuel line air to fuel ratios.
3. Quantify pulverizer air to fuel ratio.
4. Quantify individual fuel line velocity and air flow.
5. Ascertain pipe to pipe air flow balance.
6. Quantify fuel line temperature and static pressure.
7. Obtain representative fuel samples for coal fineness analysis.

Quantification of these parameters is required to ascertain pulverizer performance which is paramount in achieving optimum unit performance. Optimum pulverizer performance would require the following parameters to be achieved without compromise:

- Pipe to Pipe fuel balance within ±10% of the mean fuel flow.
- Pipe to Pipe dirty air flow balance within ±5% of the mean air flow.
- Optimized pulverizer air to fuel ratio.
- Minimum fineness level ≥75% passing 200 mesh and ≤0.3% remaining on 50 mesh.
- Pulverizer to pulverizer mass air and fuel balance within ±5% of the mean.
- Pulverizer outlet temperature ≥155°F for eastern coals and >140°F for western coals.
- Minimum fuel line velocity of 3,300 Fpm.

Figure 13-1 – Isokinetic or “Air/ Fuel” Type Sampler



Performing a Dirty Air Test

1. The velocity of "dirty air", or coal/air mixture, must be measured in each fuel line to establish proper sampling rate for the Isokinetic Sampler and to determine air flow in each fuel line. The Dirty Air Probe is a field proven device which allows the measurement of air flow in a dust-laden environment with a minimum of probe stoppage. The Dirty Air Probe is illustrated by figure 13-3. Dirty air velocity and fuel sampling measurements will be on a minimum of two (2) axes 90° apart on a vertical run of pipe. An increased number of traverse planes will be utilized when taps are close to elbows or other flow disturbances. Test taps in horizontal runs are to be avoided. Figure 13-2 illustrates the physical effects of elbows and horizontal pipe runs on coal particles.

Figure 13-2 – Physical Effects of Elbows and Horizontal Pipe Runs

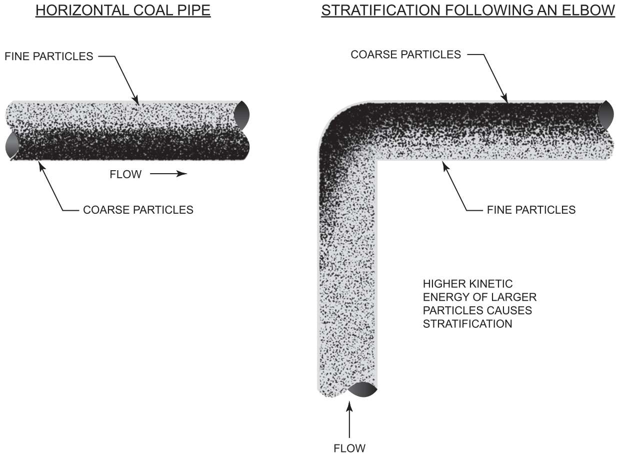
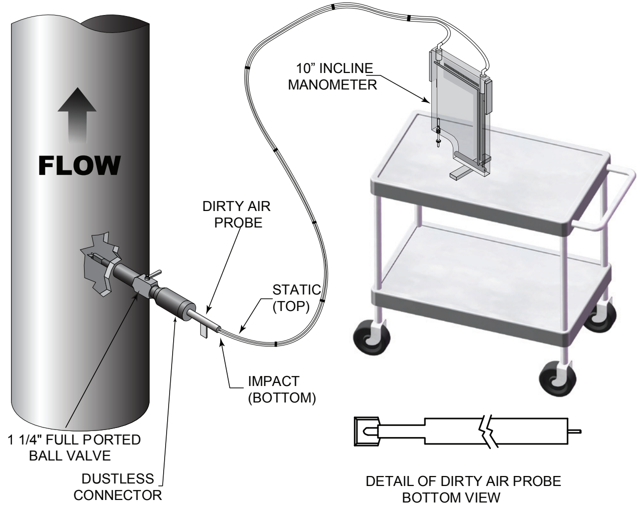


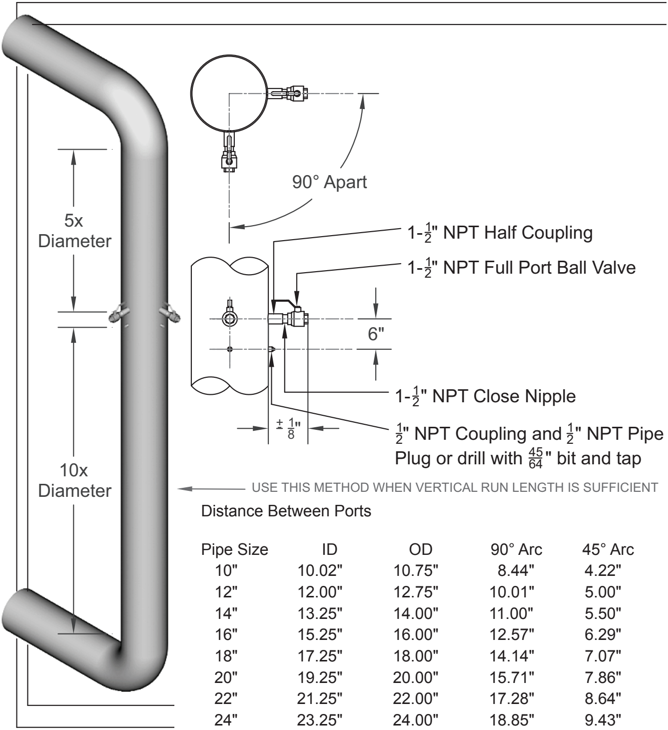
Figure 13-3 – Dirty Air Probe Setup



DETAIL OF DIRTY AIR PROBE BOTTOM VIEW

Coal line test taps, which facilitate insertion of a Dirty Air Probe, require 1¼” full-ported ball valves. Use of a Rotorprobe™ will require installation of 2” full-ported ball valves. A minimum of two (2) ports at 90° apart will be required. Figure 13-4 specifies the number of test ports required, depending on the proximity to elbows or other flow disturbances.

Figure 13-4 – Test Methods for Ascertaining Fineness



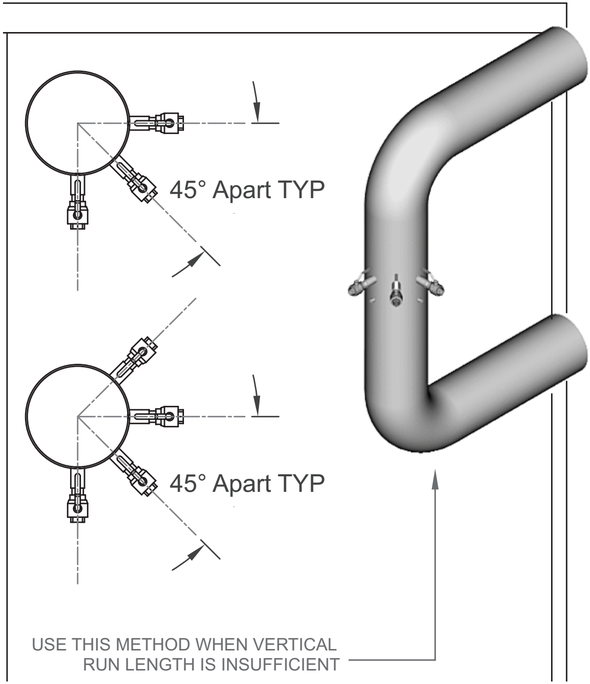
Distance Between Ports

Pipe Size	ID	OD	90° Arc	45° Arc
10"	10.02"	10.75"	8.44"	4.22"
12"	12.00"	12.75"	10.01"	5.00"
14"	13.25"	14.00"	11.00"	5.50"
16"	15.25"	16.00"	12.57"	6.29"
18"	17.25"	18.00"	14.14"	7.07"
20"	19.25"	20.00"	15.71"	7.86"
22"	21.25"	22.00"	17.28"	8.64"
24"	23.25"	24.00"	18.85"	9.43"

Notes

1. The 1-1/4" NPT connections MUST be able to accept a 1.050" diameter sample probe.
2. The 1-1/4" NPT ball valve MUST be a FULL PORTED ball valve.
3. The lengths of the ball valve and fitting assemblies should be within 1/8" in order to avoid multiple probe marking sessions.

Figure 13-4 – Test Methods for Ascertaining Fineness (Cont.)

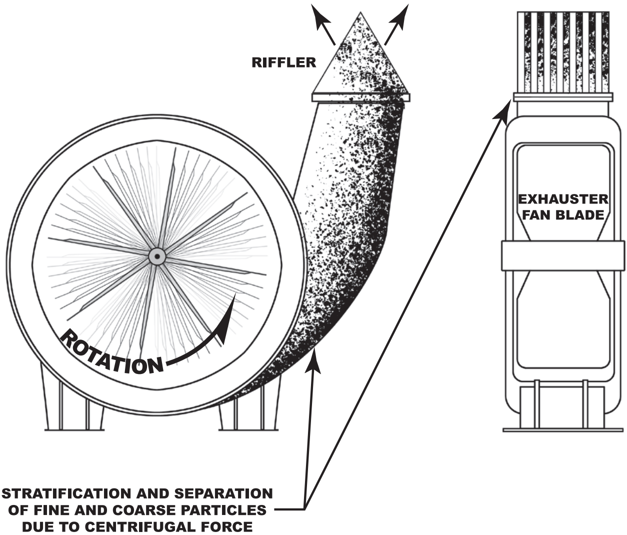


Notes

4. When the vertical run length of pipe is sufficient in length as illustrated to the left, then ports are to be placed 90° apart as shown to the left of this drawing. When the vertical run length of pipe is insufficient, then ports are to be placed 45° apart as shown to the right of this drawing.
5. Screw a 40 or 48" length of 1-1/4" pipe into each ball valve while unit is in service in order to ensure clearance. The 40" length may be used when the fuel pipe is less than or equal to 16". The 48" length must be used when the fuel pipe is greater than or equal to 18". Unit must be in service due to expansion during this check for clearance.

Coal samples, to obtain fineness, have been commonly extracted at the exhauster outlet on units equipped with CE Raymond Bowl pulverizers. Although this practice has been widely advocated, representative coal samples are not obtained. The kinetic energy of rotation imparts centrifugal forces on larger coal particles which have higher mass. The resulting propagation of a majority of the coarse coal particles to the outside of the exhauster scroll in a very small zone facilitates occupation of the highest percentage of the traverse plane by fine coal particles. With a high percentage of the traverse plane biased towards collection of fine particles, fineness results are much higher than actual. Figure 13-5 illustrates the non-representative sampling of pulverizer coal at the exhauster outlet. Due to the error associated with sampling at the exhauster, ICT is adamant in recommending that all coal samples be taken from the fuel lines.

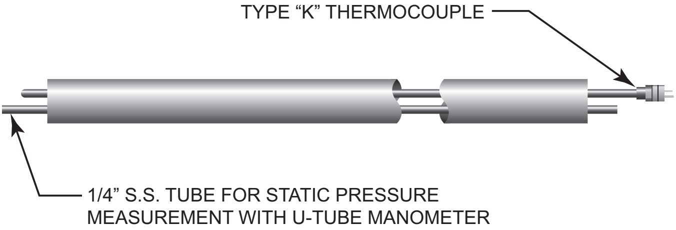
Figure 13-5 – Coal Particle Distribution at the Exhauster Outlet



2. Traverse points on the Dirty Air Probe are marked on an equal area grid in accordance with the ASME Performance Test Code for traversing circular ducts. When marking the Dirty Air Probe, be sure to offset the first mark to accommodate for the length of the test port nipple, pipe wall and dustless connector. This ASME standard, for pipes with 10” or larger diameters, is illustrated in figure 4-2 and on the back cover of this booklet.
3. Two equal length tubing sections are cut to desired length. The tubing is then taped or bound together and one tube is marked on both ends to identify it as the “high–pressure” (impact) line. The remaining tube, which is unmarked, is identified as the “low–pressure” (static) line.
4. A 10” vertically inclined manometer is set up on a level and stable location. Open the low and high pressure valves for the manometer, ensure the manometer is level using the integral leveling bubble and zero the manometer. Tubing is then attached to the correct sensing lines on the Dirty Air Probe and the manometer.
5. The following data should be recorded for each test:
    - Coal pipe designation
    - Individual velocity heads for each traverse point [typically (24) points - (12) per port]
    - Temperature and static pressure for each pipe
6. Prior to inserting the Dirty Air Probe, ensure the incline manometer is level and zeroed.
7. Insert the Dirty Air Probe into the dustless connector, open the full-ported ball valve and insert the Dirty Air Probe to the first mark with the probe’s pointer directed into the flow. The Dirty Air Probe will seal the port. Allow the incline manometer indication to stabilize. Record and move to the next point. Repeat this process for all (12) traverse points.
8. Between ports, disconnect the tubing from the probe; blow out the Dirty Air Probe’s sensing lines and repeat the traverse on the remaining port(s).
9. Insert the Static and Temperature Probe into one of the ports in the same manner that the Dirty Air Probe was inserted. When inserting the Static and Temperature Probe, the U-tube should be disconnected.

The tight seal between the dustless connector and probe will compress the air in the dustless connector and may blow out the U-tube fluid. Connecting the tubing to the U-tube manometer after the ball valve is open and the probe inserted prevents loss of U-tube fluid. Record static pressure indicated by a U-tube manometer and temperature indicated by a digital thermometer. The Static and Temperature Probe is illustrated by the figure shown below.

Figure 13-6 – Static and Temperature Probe



10. Calculating dirty air data is similar to reducing clean air data. The equations utilized to reduce dirty air flow traverse data are listed in Section A of the Calculations and Formulae located in the back of the book.
11. After determination of the dirty air velocity in a given fuel line, isokinetic coal samples are extracted. The Isokinetic Coal Sampler Probe, pictured in figure 13-1, is marked identically to the Dirty Air Probe.
12. Calculate the sampler orifice differential pressure based on the dirty air velocity traverse. Sampler differential is monitored by a standardized orifice and an inclined manometer. The average square root velocity head observed by the Dirty Air Probe is entered into the following formula: $\Delta P = 1.573 \times (\text{avg. } \sqrt{Vh})^2 \times (\text{Probe K Factor})^2$.

    The simplified formula above indicates an orifice ΔP which will yield an average velocity through the sampling tip equivalent to the average velocity of the coal and air mixture passing through the fuel line. This is referred to as isokinetic sampling.

13. Connect the tubing to the incline manometer and the orifice sensing lines. The orifice sensing line upstream of the orifice (closest to the filter canister) should be connected to the high pressure side of the incline. The orifice sensing line downstream of the orifice is connected to the low pressure side of the incline. Refer to figure 13-1 for a schematic.

    The desired differential pressure will be monitored and maintained at all times while the probe is in the fuel line. A needle valve is placed on the air supply line to manipulate the differential pressure. Prior to insertion of the sampling probe, place your hand over the aspirator discharge to minimize collection of coal during insertion. Insert the sampling probe (with the pointer 180° from the direction of flow) onto the first mark, rotate the probe pointer into the direction of flow and simultaneously start the stop watch. Remove hand from aspirator discharge and establish and maintain proper orifice differential by adjusting the needle valve.

14. The sample probe, which is marked in the same manner as the Dirty Air Probe, will remain at each traverse point for an equal and precise time. Sampling time is very critical and great care should be taken to ensure the correct sampling time is obtained for each individual point. The sample time is determined by the number of sampling points that is determined by the number of test ports. The following sampling times are typical:

Ports	**Traverse Points**	**Time per Point**	**Total Sample Time [min]**
2	24	10	4
3	36	7	4.2

15. After traversing each port, turn off the air supply and remove probe from pipe.

16. Once all ports have been traversed, disconnect tubing from orifice sensing lines and turn on air. Shake sample transport hose and tap cyclone to insure all coal sampled is evacuated.

17. Carefully empty the entire sample collected in the sample jar and filter canister into a sample bag labeled with the pipe designation, test number and date. Take care to ensure that the entire sample is emptied into the sample bag. Sample weight will be utilized to calculate fuel flow.
18. Replace filter, sample jar and repeat process on the remaining fuel lines. In some cases, especially while sampling high moisture coal, the sampler should be thoroughly cleared of any residual coal dust or scum, prior to reassembly, by blowing high pressure air through the sampler components.
19. Determine net weight of each of sample, record on data sheet and perform fineness sieve analysis on all coal samples.
20. Formulas to reduce all dirty air and isokinetic coal sampling data are in Section A of the Calculations and Formulae located in the back of the book.

Coal Sieving Procedure

1. Air drying of sample is recommended if high moisture (>10%) coal is being fired or sieving is not performed immediately after sample extraction. This is to prevent the coagulation of sample on top of sieve screens, which prevents particles from passing through screens and results in non-representative coal fineness. Coagulation of coal sample usually appears as small balls of coal on 100 mesh screens. ASTM D-197 specifies drying at 18 – 27°F above room temperature with (1) to (4) air changes per minute until weight loss is less than 0.1% difference.

   This step can usually be eliminated if the following criteria has been established:

   - Pulverizer discharge temperature above 160°F (70°C)
   - Fuel moisture is moderate
   - Collected samples are placed in air-tight Ziploc bags
   - Sieving is performed immediately after extraction
   - No coagulation of coal is observed during sieving

2. Remove (50) grams of coal from the sample. This is done by using an ASTM riffler, or by "rolling" the sample (usually between 200 g and 800 g). ICT advocates the riffler method, which is cleaner and more efficient. A (50) gram sample can not be simply "scooped" or "spooned" from the whole sample, as this may result in a disproportionate quantity of fine or coarse particles. If sample is not exactly 50 g, be sure to weigh and record initial sample weight. Figure 14-1 illustrates a coal riffle as specified by ASTM D 197-87.

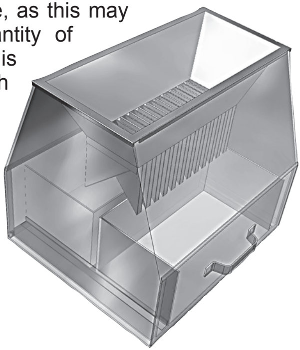


Figure 14-1 – Coal Riffle

3. Before placing the fifty (50) gram coal sample in a series of 50, 100, 140 and 200 mesh U.S. sieves, the initial weight of each of the sieves, inculding the “passing 200” pan, should be recorded.
4. Shake the sample through a series of 50, 100, 140 and 200 mesh U.S. Standard sieves. ICT recommends using a Ro-tap® for a minimum of (20) minutes. Figure 14-2 illustrates the order of the sieves.
5. Record the weight of coal residue by weighing the sieves and “passing 200” pan and subtracting the difference from the inital weight. Great care should be taken in weighing coal sample residue on each screen. Residue on 50 mesh will be very small and must be weighed accurately to yield representative data. A scale capable of accuracy to 1/1000 (0.001) must be utilized.

Figure 14-2 – Typical Arrangement For Coal Fineness Analysis

PLACE 50 GRAMS OF COAL ON STACKED 50,100,140 AND 200 MESH SIEVES AND SHAKE FOR 20 MINUTES

6. Calculate the percentage of total sample passing 50, 100, 140, and 200 mesh.

Initial Sample Weight	SW(g)	50.00
Weight of residue on 50 mesh	R_1(g)	_____
Weight of residue on 100 mesh	R_2(g)	_____
Weight of residue on 140 mesh	R_3(g)	_____
Weight of residue on 200 mesh	R_4(g)	_____
Weight of sample in pan *(Passing 200 mesh)*	R_5(g)	_____

% Passing 50 mesh

$$\frac{(SW - R_1) \times 100}{SW}$$

% Passing 100 mesh

$$\frac{[SW - (R_1 + R_2)] \times 100}{SW}$$

% Passing 140 mesh

$$\frac{[SW - (R_1 + R_2 + R_3)] \times 100}{SW}$$

% Passing 200 mesh

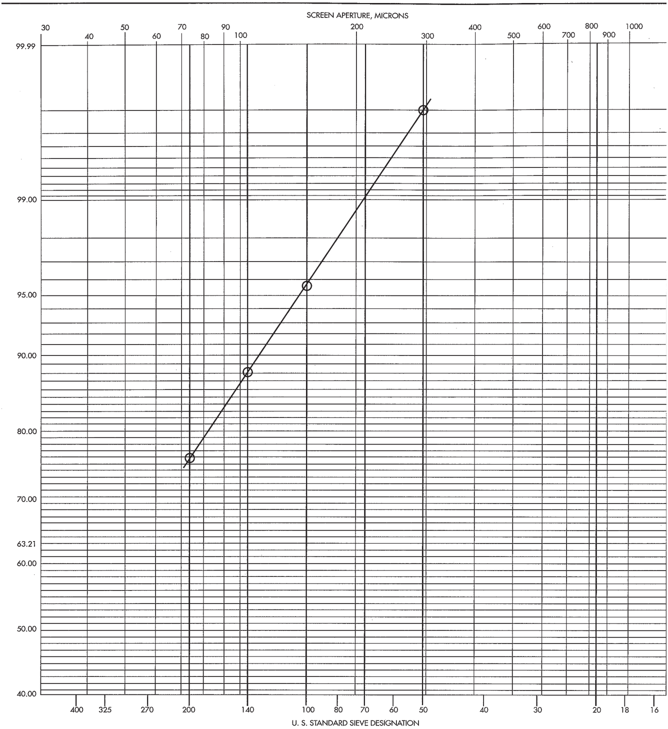
$$\frac{[SW - (R_1 + R_2 + R_3 + R_4)] \times 100}{SW}$$

% Recovery

$$\frac{(R_1 + R_2 + R_3 + R_4 + R_5) \times 100}{SW}$$

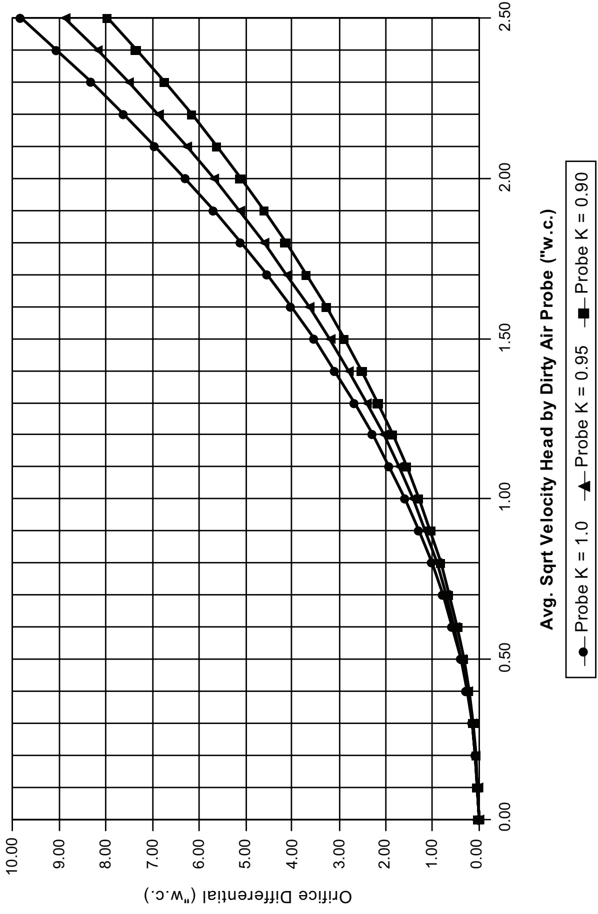
7. Plot percentages passing each sieve to the Rosin and Rammler equation. The percent passing 50, 100, 140 and 200 mesh should fall on a straight line. If the plotted line is not linear, the sample is non-representative and must be disregarded. The figure below illustrates representative coal fineness plotted against the Rosin and Rammler equation. Non-representative sampling is the result of one of following:
    - Sampling rate not isokinetic
    - Testing error or error in calculating sampling rate
    - Sample splitting or coal sieving error
    - Excessive sample moisture

Figure 14-3 – Coal Fineness Plotted Against the Rosin Rammler Equation



PLOT OF ROSIN AND RAMMLER EQUATION FOR USE WITH PULVERIZED COAL

Figure 15-1 – Relationship of VH and Coal Sampler Orifice Differential



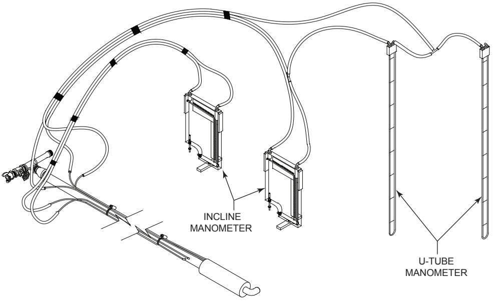
Flyash Sampling

Flyash Loss on Ignition (L.O.I.), or unburned carbon, is indicative of combustion efficiency. For this reason, an "in-situ" flyash sample is frequently extracted for diagnostic or quantitative reasons. Two types of duct-inserted flyash samplers are utilized by ICT to collect flyash samples: High Volume Samplers and Isokinetic Samplers. The High Volume Sampler is expedient, simple and is usually used for diagnostic purposes or periodic monitoring of flyash L.O.I. The High Volume Sampler collects a larger bulk sample than isokinetic sampling, thus allowing shorter collection time. Another High Volume Sampler benefit is its simplicity. It requires little training or expertise of persons performing the test. In some cases, a more accurate sample must be collected for contractual specification, compliance with flyash sale restrictions or dust loading. In these cases, an Isokinetic Sampler must be utilized.

Isokinetic Flyash Sampler

For collection of an isokinetic flyash sample, ICT currently uses a variation of the B&W "SLM" Probe. We have found this to be a reliable and efficient means of collecting isokinetic ash samples. The probe uses a three-hole "Fecheimer" head to measure velocity head and an "in-line" calibrated square-edged orifice to maintain the required sampling velocities. A picture of the probe is shown below.

Figure 16-1 – Isokinetic Flyash Sampler SLM Style Probe



High Volume Flyash Sampler

Unlike the Isokinetic Flyash Sampler, the Volumetric Flyash Sampler requires no measurement of velocity heads, temperature, null balance or manipulation of supply airflows. The aspiration rate is simply set to 25 psig, the probe inserted to the first traverse point and the stopwatch started. Each traverse point is sampled for equal time periods.

Figure 16-2 – High Volume Sampling Head

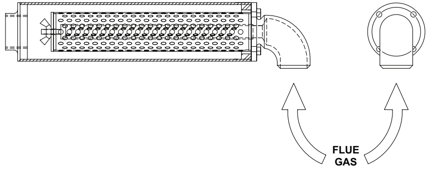
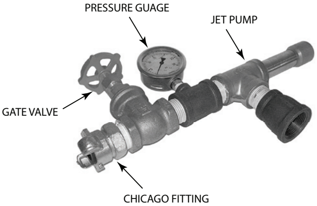
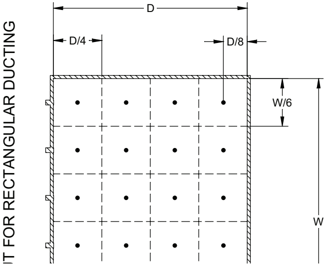


Figure 16-3 – High Volume Aspirator



Both types of samplers are designed with 3” diameter sampling heads, thus requiring a 4” access port for testing purposes. The length of each probe can be customized for specific applications.

Figure 16-4 - Test Grid Layout for Rectangular Ducting

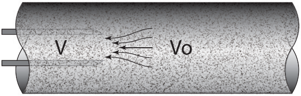


Isokinetic Flyash Sample Collection and Analysis

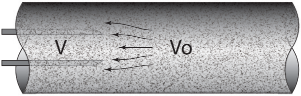
A flyash sample is said to be collected “isokinetically” when the velocity of the dust laden gas flow entering the flyash probe collection nozzle is equal to the velocity of the gas flow in the duct. It is extremely critical for the velocities to be equal if a representative sample of ash is to be collected. If sampling velocity is lower than duct velocity (sub-isokinetic), the collected sample will be skewed with a higher percentage of coarse particles. If the collection velocities are higher than duct velocities (super-isokinetic), a disproportionately high quantity of fine particles will be collected. Figure 17-1 illustrates the effect of sub-isokinetic and super-isokinetic sampling.

Figure 17-1 – Isokinetic Sampling Opposed to Non-Isokinetic Sampling

Probe velocity (V) greater than (V_o)
Deficiency of coarse particle collection



Probe velocity (V) less than (V_o)
Excessive coarse particle collection



Probe velocity $V = V_o$
Representative or “Isokinetic” particle collection

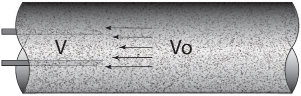


Figure 17-2 – Isokinetic Flyash Sampler

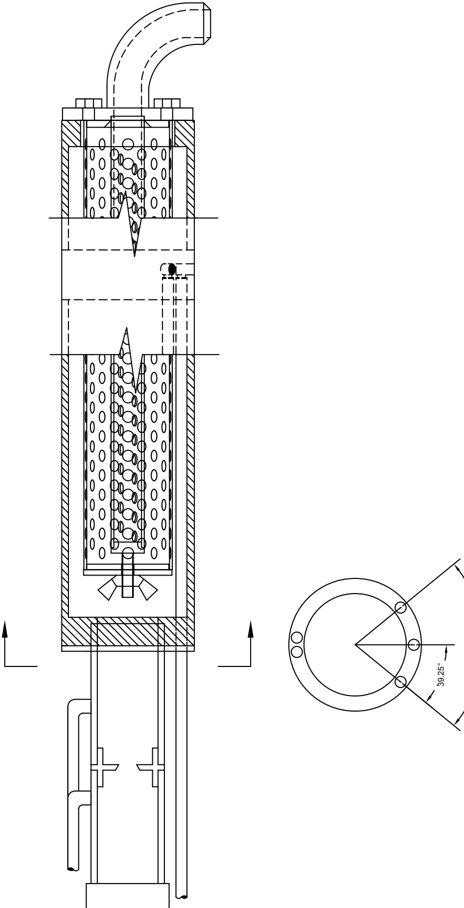
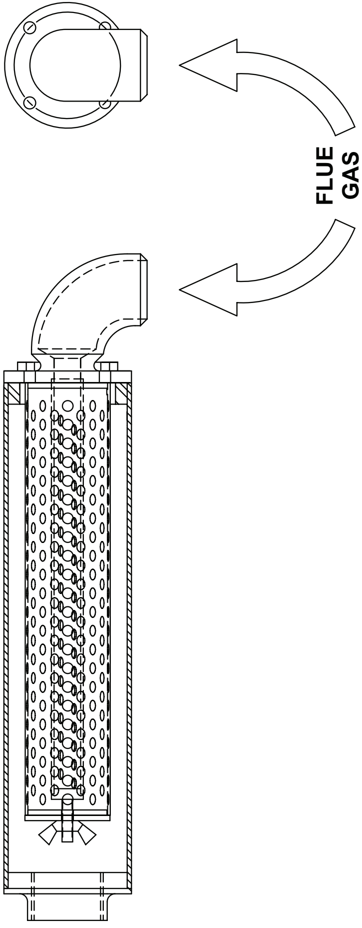


Figure 17-3 – High Volume Flyash Sampler

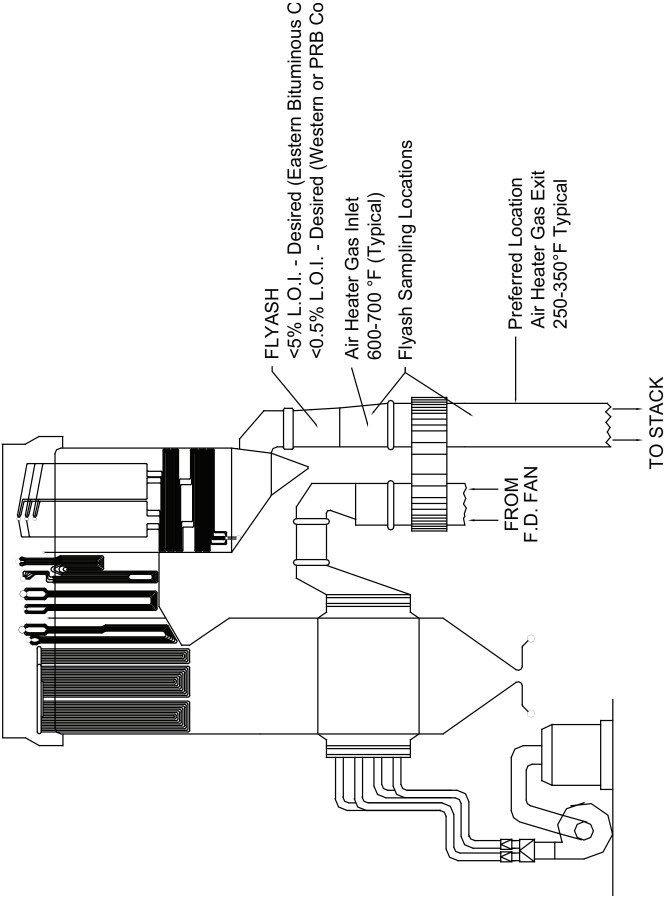


Test Tap Location and Lay-out

According to the ASME Test Code PTC 38, “Determining the Concentration of Particulate Matter in a Gas Stream,” test tap layout should ideally be such that sampling access ports and traverse points are selected to permit sampling in zones of equal areas. The traverse grid should facilitate at least one traverse point for every 9 ft^2. For example: a 12’ × 36’ duct with a cross-sectional area of 432 ft^2 will require a minimum of (48) traverse points. The traverse grid should be located in a straight run of duct work (constant cross-sectional area), preferably a vertical run, in order to minimize stratification of the medium. In addition, the traverse grid should be located a minimum of eight (8) duct diameters downstream and two (2) duct diameters upstream from the nearest flow disturbance. Since these criteria are often impossible to meet, test taps are generally located in the “best possible” location. This is acceptable if all parties involved in the testing agree. Probe accessibility, lighting, power facilities, etc. should also be considered when choosing a location. An illustration of an equal area test grid for a rectangular duct is illustrated in Figure 4-1.

Flyash samples are typically collected at the air pre-heater’s gas inlet or gas outlet ducting. The air heater gas outlet is usually the preferred sampling location due to lower gas temperatures, making probe handling easier. Stratification of ash loading is also less prominent at the air heater gas outlet due to the homogenization effect of the air heater’s basket type heating surface. The Isokinetic Flyash Sampler’s head is 3” in diameter and will require test ports of 4” pipe or larger. Figure 17-4 illustrates typical locations for collecting a flyash sample.

Figure 17-4 – Typical Locations For Collection of a Flyash Sample



Necessary Test Equipment

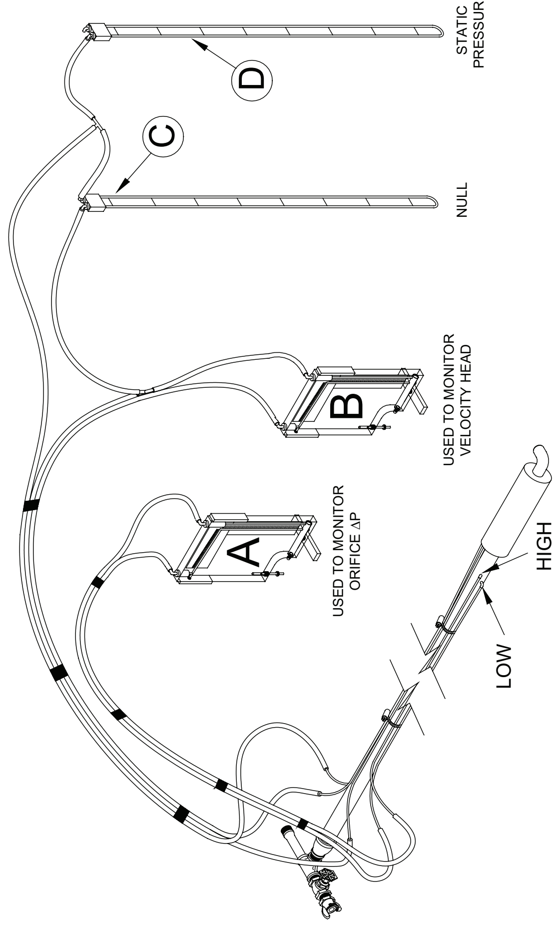
Quantity	Description
1	Isokinetic Flyash Sampler Head with sampling nozzle. Sampler Head should have a calibrated nozzle and orifice coefficient.
1	3/4” standard pipe threaded on both ends, suitable in length for traversing the depth of the duct.
5	Lengths of 1/4” X .035” stainless steel tubing to connect to the probe head. The length of the tubing should be slightly longer than that of the pipe.
1	Magnahelic gauge panel or suitable substitution of two inclined manometers capable of measuring a velocity head and maintaining an orifice differential simultaneously. A Dual Scale incline may also be used. In addition, two “U-tube” manometers will also be necessary for measurement of “null” balance and gas flow static pressures.
1	Temperature measurement assembly including: one type “K” chrome alumel thermocouple of sufficient length to attach to the probe, one type “K” lead wire of sufficient length, and one potentiometer.
1	One set of five strands of tubing (or similar) with an overall length at least 10’ to 12’ longer than the total length of the sampling probe assembly. Each of the strands should be clearly marked on each end for identification. Several strands of loose tubing along with a couple of tees for the tubing will also be necessary.
1	One aspirator assembly with 1” X 1” X ¾” jet pump.
1	Length of ½” or ¾” air line sufficient to connect the air supply to the probe. The air line should have a needle valve (or similar) for accurate control of the aspirating air flow rate.
1	One box of Gelman fiberglass filter paper (Type AE, 8” X 10” sheets) will be required.
1	One box of storage bags for collection of the ash following each test.
1	Stopwatch
Several	Gaskets for the nozzle assembly. It will be necessary to have at least three of each style of gasket for the nozzle assembly of the sampler.

Assembly of the Probe and Test Equipment

The first step in the procedure is to assemble the probe and connect all necessary sensing lines. The ¾" pipe is first threaded into the welded coupling on the Isokinetic Flyash Sampler Head on the end closest to the calibrated orifice. All threaded junctions should be effectively sealed by using Teflon tape or an acceptable substitute on the threads. Once this is accomplished, the stainless steel tubing can be connected to the fittings on the sampler head. The stainless steel tubing should be numbered (1) through (5) and connected accordingly:

1. Connect to the sensing line exiting the impact hole (center hole of the three Fecheimer holes).
2. Connect to one of the sensing lines exiting one of the null or static holes adjacent to the impact hole.
3. Connect to the remaining sensing line exiting the remaining "null" or static hole adjacent to the impact hole.
4. Connect to the fitting on the ¾" pipe exiting the sampler head located between the in-line orifice plate and the sampler head. This will become the "high" pressure side of the orifice differential.
5. Connect to the fitting on the opposite side of the orifice, referred to as the "low" pressure side.

Figure 17-5 – Set-up for Isokinetic Flyash Sampling



Once the stainless steel tubing has been connected, a thermocouple of sufficient length can be positioned alongside the tubing. Make sure that the tip of the thermocouple extends no closer than 3” from the Fecheimer holes on the sampler head. Hose clamps are then used to secure the tubing and thermocouple to the pipe. The aspirator assembly is then threaded onto the other end of the pipe. The aspirator is usually lined up with the impact hole on the Fecheimer head to provide a reference point once the probe is in the ductwork.

Place the needle valve inline between the air supply line and the line connected to the probe.

The next step is to setup the inclined and U-tube manometers, taking special care to ensure that all valves are open, the inclines are leveled and everything is properly zeroed. The sketch on the previous page illustrates a schematic of the proper tubing connections (shown without the full length of stainless steel tubing). Connect one end of one piece of tubing to the “high” side of the incline manometer labeled “A” and the other end to the “high” side (closest to the sampling head) orifice connection. Repeat for the low side. Incline manometer “A” should be hooked up to measure the ΔP across the in-line orifice. Connect one (1) common end of all three (3) strands of the triple tubing to one (1) of each of the remaining tubes (2 null, 1 impact). Install a “tee” on the end of each of the tubes hooked up to the null fittings. Connect the remaining tube (impact) to the “high” side of incline manometer “B.” Connect two (2) pieces of tubing to each of the tees. The two (2) pieces of tubing on one (1) of the tees should each be connected to separate U-tube manometers (“C” & “D”). The two (2) other pieces of tubing should be connected; one (1) to the “low” side of incline manometer “B” and the other to one (1) of the U-tube manometers. Once this is complete, leak check all sensing lines and subsequent tubing. The final step of the assembly is to load the filter paper into the perforated cylinder of the nozzle and insert the nozzle assembly into the sampling head.

Carefully roll one (1) sheet of filter paper lengthwise and insert it into the perforated cylinder of the nozzle assembly, making sure that no gaps are present between the bottom of the cylinder and the paper. The paper should fill the inside diameter of the cylinder fully and no tears on the paper should be evident.

Traverse Procedure

1. The first step in testing is to establish steady state conditions for the unit. All soot blowing should be completed prior to commencement of the testing. The unit will need to remain steady for the duration of the test (approximately one (1) hour per duct sampling time will be required).
2. Turn on the air supply and regulate it to maintain approximately 4" w.c. of differential across the orifice (differential indicated on incline manometer "B"). This prevents the negative pressure inside the ductwork from damaging the filter once the probe is inserted into the duct. Insert the probe into the duct and position it on the mark providing the deepest depth. By starting at the deepest mark, the probe has some time to cool as it is worked out of the duct and is generally easier to handle when moving between ports. Be sure to use proper safety equipment and hand protection with an appropriate level of protection for the temperature of the air or gas being measured.
3. At no time after the air has been turned on should the tip of the nozzle come into contact with the ground or any other surface. The aspirating effect could pick up foreign matter that would contaminate the ash sample. With this in mind, the access ports should be cleaned prior to testing to remove any accumulations on the interior surfaces.
4. Once the probe is positioned at the first mark, rotate the probe slowly from side to side until the null U-tube (U-tube "C") is balanced. This balance is achieved usually no more than 20° off the centerline of the duct. Take care to ensure the sampling tip and impact hole are positioned into the flow as the probe is inserted. The direction of the aspirator tip will also help to give relative position and help to keep the probe directed into the flow. An erroneous null balance can be achieved with the probe head turned directly away from the flow.
5. Once the null position is achieved, start the stopwatch. Sampling time for each point in the traverse duct will depend on the total number of points and the agreed upon total sampling time for each duct. Generally, one hour per duct is adequate time to collect enough sample for analysis.

6. While maintaining the null position, record the velocity head reading off of incline “A”, the temperature from the potentiometer and the static pressure off of U-tube “D”. Using the velocity head recorded, it will be necessary to adjust the air supply to obtain an isokinetic sample. The formulas that will be utilized are in Section A of the Calculations and Formulae located in the back of the book. For a given sampler, the Sampler Orifice Coefficient is known and the calculation term can be reduced to a constant. For most samplers, this constant is approximately 4.0. It is then simply a matter of multiplying the measured velocity head by a factor of 4.0 to obtain the necessary orifice differential. Complete these steps for each subsequent traverse point.

   Note: Never turn off the aspirating airflow while the probe is inserted into the duct. The negative suction on balanced draft units is sufficient to pull all or a part of the sample out of the probe. The probe can be moved from port to port without adjusting the airflow.

7. After all points have been sampled, extract the probe and allow it to cool sufficiently before attempting to dismantle it. Remove the four bolts securing the nozzle assembly to the head. Make sure that the environment is relatively draft-free before dismantling the nozzle assembly. With the assembly vertical, remove the two nuts securing the nozzle tip and tap the nozzle as it is removed to shake off any accumulation. Dump the perforated cylinder contents into one of the bags labeled with the test number, date, duct sampled and time. Carefully remove the filter paper from the perforated cylinder, making sure not to tear the paper significantly. Lightly scrape the inside surface of the paper to loosen any ash accumulation that may have bonded to the paper and empty this into the bag. Reload the cylinder with filter paper, secure the nozzle tip to the cylinder and replace the nozzle tip assembly in the probe head. The probe is then ready for the next test.

Collection of a Dust/Gas Sample on an Oil-Fired Boiler

Flyash/dust sampling is often useful on oil-fired boilers since it provides relevant information on particulate emissions and emission pH levels. The collection of a dust/gas sample can be conducted either isokinetically, as mentioned previously, or more often by simple volumetric means. With a Volumetric Sampler, there is no need to measure velocity heads, temperatures, maintain null balance or vary aspirating airflow rates. The pressure at the inlet of the aspirator is simply set to 25 psi, the probe is inserted and set to the first point, the nozzle opening is directed into the flow and the stopwatch is started. In either case, the preparation and many of the test procedures are much the same. The layout and number of traverse points is identical. For dust/gas sampling on oil-fired boilers, the duration of the sampling is increased to a minimum of two (2) hours for each duct sampled in order to collect enough sample.

One sheet of fiberglass filter paper (Gelman type AE) is placed in a Ziploc™ bag and weighed. The filter paper is then removed, rolled lengthwise, and inserted in the filter canister of either an isokinetic or volumetric perforated cylinder. The cylinder is then attached to the nozzle tip and the entire nozzle tip assembly is inserted into the probe head. The probe is then ready for use.

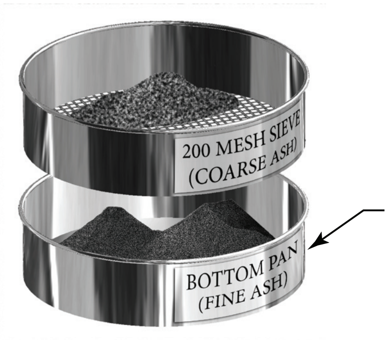
Once the sampling is complete, the assembly steps are reversed and the filter paper is removed from the nozzle tip assembly and bagged. The filter paper, bag and sample are then weighed and the difference between the initial and final weights is the amount of dust/gas sample collected. The analysis of the deposits on the filter paper is a way of obtaining a quick overview of combustion characteristics in the furnace. Differences in dust/gas loading between ducts can give a relative indication of combustion efficiencies between furnace left and right sides. In addition, a heavy black deposit of ash on the filter paper may indicate poor combustion characteristics at the burner front. This is usually a product of one or more of the following: poor secondary air balance, improper register settings, atomizer pressures, worn, damaged or clogged oil gun tips, etc. Any of these possibilities would warrant further specific testing in order to pinpoint the problem.

Procedure for Sieving a Flyash Sample

Generally, the ash collected from each duct is divided into two (2) samples. One (1) sample, of approximately five (5) grams, is set aside as the composite sample. The other sample is measured from the remaining ash. Ideally, a 10.0 gram sample is weighed and placed on a set of sieves (50, 100, 140 and 200 mesh) to be shaken for twenty (20) minutes. Graphing the fineness for the ash passing these particular meshes should produce a line very similar in slope and position to that graphed from an isokinetic coal fineness taken from the same unit. If it does not, it could indicate non-representative sampling of either coal or ash.

Once the finenesses have been calculated, the ash passing 200 mesh is to be burned for an L.O.I. (loss on ignition), along with the composite sample. The procedure for burning an ash sample will be discussed later. As a rule of thumb, L.O.I.'s for the ash passing 200 mesh should be no more than 2%. L.O.I.'s greater than 2% usually indicate a combustion problem; i.e., insufficient secondary air flow, secondary air imbalance, poor mixing at the burner front, etc.

Figure 17-6 – Sieve Arrangement for "Fine" Ash



PLACE 10 GRAMS OF ASH
ON STACKED 200 MESH PAN
AND SHAKE FOR 20 MINUTES

DETERMINE L.O.I. OF RESIDUE
ON 200 MESH SCREEN AND IN PAN

L.O.I. OF FINE ASH MUST
BE LESS THAN 2%*

*EASTERN BITUMINOUS COAL

Procedure for Burning a Flyash Sample for L.O.I. Determination

Necessary Equipment

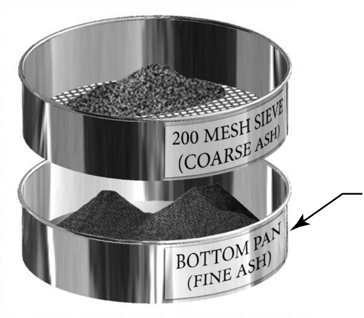
- A small oven capable of maintaining temperatures between 300-1500°F (150-815°C).
- A set of ceramic crucibles for burning the ash.
- A set of pincers or tongs for handling the crucibles.
- A highly accurate scale (balance) for measuring the ash samples. The scale should have a readability of 0.1 mg with a repeatability of + 0.1 mg.

Label each of the crucibles and then preheat them to 300°F (150°C) for approximately fifteen (15) minutes. Weigh each crucible while hot (W_C). Add one (1) gram of sample ash to the crucible as it remains on the scale and record the sample and crucible weight. Insert the crucible with the sample into the oven and leave it for one (1) hour at between 300-500°F (150-260°C). Remove the crucible with sample, reweigh, record it and compare the weight to the initial weight. The difference in the two weights is the amount of water driven off. Replace the crucible with sample in the oven at 300-500°F (150-260°C) and leave it for thirty (30) minutes. Remove, weigh and record the crucible with sample. Continue this process until the weight remains constant. RECORD THIS WEIGHT (W_{CSD}). Replace the crucible with sample in the oven and cook the sample at 1500°F (815°C) for three (3) hours. Remove, weigh and record the crucible with sample weight. Replace the crucible with sample and cook at 1500°F (815°C) for thirty (30) minutes. Remove, weigh and record the crucible with sample weight. Any difference indicates that there is still carbon present in the ash. Continue this procedure until the weight remains constant (W_{CSFW}). Once the weight remains constant, the flyash L.O.I. can be calculated using the equation in Section A of the Calculations and Formulae located in the back of the book.

Flyash Loss on Ignition Analysis

To diagnose certain combustion problems, ICT has found it very helpful to divide a collected ash sample into two samples to ascertain composite and fine ash particle Loss On Ignition (L.O.I.). One half of the sample is burned to provide a “composite” L.O.I. and the second half of the sample is sieved through a 200 mesh screen to ascertain “fine ash particle” L.O.I. Ash should be sieved through the 200 mesh sieve using a “Ro-Tap” for approximately 20 minutes. Typically, 10 grams of ash is sufficient for sieving and subsequent L.O.I. analysis. As a rule of thumb, L.O.I.’s for the ash passing 200 mesh should be no more than 2.0%. L.O.I.’s greater than 2% indicate a mixing problem at the burners and/or insufficient air for combustion at the burners. This could be the result of air in-leakage, insufficient secondary air flows, secondary air imbalance, poor mixing at the burner front caused by non-optimum stroking of auxiliary and fuel-air dampers or higher than desired primary air flow. Fine ash carbon (passing 200 mesh) will completely combust if it is exposed to oxygen with adequate retention time in the furnace. Higher than desired composite L.O.I. (>5%) with “fine” ash L.O.I. of < 2% would indicate that pulverizer coal fineness is responsible for higher than desired flyash L.O.I.

Figure 18-1 – Sieve Arrangement for Fine Ash L.O.I. Determination



PLACE 10 GRAMS OF ASH
ON STACKED 200 MESH PAN
AND SHAKE FOR 20 MINUTES

DETERMINE L.O.I. PASSING 200 MESH
PARTICLES IN BOTTOM PAN

L.O.I. OF FINE ASH MUST
BE LESS THAN 2%*

*EASTERN BITUMINOUS COAL

Fine ash L.O.I. and composite L.O.I. comparisons can be used as an indicator of whether or not higher than desired flyash is caused by fineness or burner and/or combustion air related inadequacies. An example of using “fine” and “composite” ash L.O.I. comparisons is as follows:

Case I

Composite flyash Loss on Ignition……10.5% L.O.I.

Fine flyash Loss on Ignition .... 8.75% L.O.I.

The fine ash L.O.I. indicates insufficient oxygen in the furnace or poor mixing of the combustion air and coal at the burners and is responsible for high flyash L.O.I.

Fine ash, ash that has passed a 200 mesh sieve, will burn when the carbonaceous particles are exposed to oxygen for a sufficient time above the ignition temperature of carbon. In this case, high flyash L.O.I. is not caused by poor fineness. In this particular case, a reducing atmosphere was observed in the furnace as a result of air in-leakage. This resulted in 83% of the total carbon in ash (L.O.I.) being in the fine ash. If the carbonaceous fine particles were exposed to oxygen by maintaining sufficient O_2 level in the furnace, complete carbon burn-out would have been achieved resulting in 2% or lower fine particle flyash L.O.I.

Case 2

Composite flyash Loss on Ignition... 12.2% L.O.I.

“Fine” flyash Loss on Ignition............ 1.2% L.O.I.

In this particular case, fine ash L.O.I. was acceptable, indicating coal was of satisfactory fineness and air was mixed effectively resulting in carbon burn-out. The high composite L.O.I. but low fine ash L.O.I. indicates that poor coal fineness is responsible for the high flyash L.O.I.

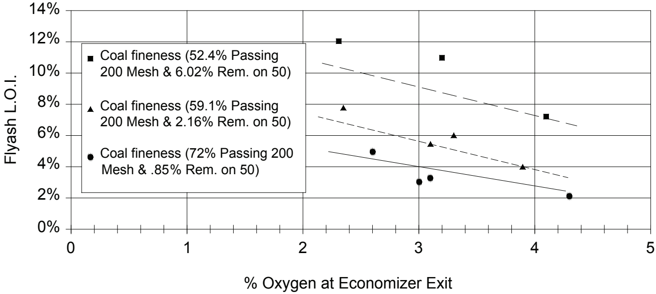
The following major areas that should be investigated upon experiencing higher than desired L.O.I. :

- Coal fineness
- Primary airflow
- Fuel balance between individual burner lines
- Furnace O_2 and air in-leakage
- Optimization of Fuel-Air and Auxiliary Damper Characterizations (T– type)

Coal Fineness

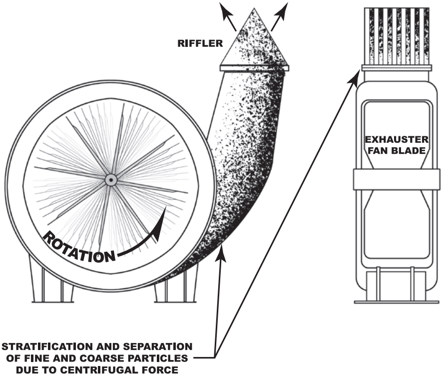
Higher coal fineness allows fuel to burn more rapidly by increasing the surface area of coal particles for the chemical reaction of combustion to take place. As combustion is completed faster, the center of combustion is lowered in the furnace allowing more time for water wall absorption and homogenization of flue gas. This results in lower furnace exit gas temperature which in turn reduces de-superheating spray flow and slagging. ICT's experiences have always indicated that fuel balance improves as coal fineness improves. A minimum of 75% passing 200 mesh and less than 0.3% remaining on 50 mesh is required to achieve optimum combustion. Preferably fineness should be 82% passing 200 mesh and <0.3% remaining on 50 mesh.

Figure 18-2 – Effects of Coal Fineness on L.O.I.



Collection of fineness samples at the exhauster outlet rather than in fuel lines can sometimes be deceiving. In some cases, fineness samples collected at the exhauster outlet indicate 200 mesh fineness that is 10% or higher than that observed in burner lines. Although this practice has been widely advocated, representative coal samples are not always obtained. The kinetic energy of rotation associated with the exhauster imparts centrifugal forces on larger, higher mass coal particles. This results in the propagation of a majority of coarse coal particles to the outside of the exhauster scroll in a very small zone and facilitates the occupation of finer coal molecules to the highest percentage of the traverse plane. With a high percentage of the traverse plane biased towards collection of fine particles, fineness results are much higher than actual. Figure 18-3 illustrates how the exhauster's rotation can contribute to non-representative sampling of pulverizer coal at the exhauster outlet. Due to the error associated with sampling at the exhauster, ICT is adamant in recommending that **all coal samples be taken from the fuel lines.** Improving coal fineness will result in direct improvement in flyash L.O.I. The previous graph illustrates actual testing data showing the typical effect improving coal fineness on a tangentially fired unit equipped with low NOx burners.

Figure 18-3 – Coal Particle Distribution at the Exhauster Outlet



Primary Air Flow Control

Maintaining optimum primary air flow is critical from a flyash L.O.I. standpoint as well as unit heat rate. High primary air flow causes higher flyash L.O.I. through two mechanisms. First, it will decrease achievable fineness levels. Second, if primary air flow is higher than optimum, the primary air and coal mixture leaving the coal nozzles will "out run" the secondary air delaying the mixing of secondary air with the fuel entering the furnace.

Burner Line Fuel Balance

Fuel balance between each pulverizer's four fuel lines must be within ±10% deviation from the mean. Achieving ±10% fuel balance is more challenging on bowl mills equipped with exhausters and riffles than other pulverizer types. Less than optimum coal fineness and high primary air flow both result in less desirable fuel balance. Fuel balance will be most favorable with >75% passing 200 mesh, <0.3% remaining on 50 mesh fineness and optimum pulverizer primary air flow.

Figure 18-4 – Burner Line/ Riffle Fuel Distribution

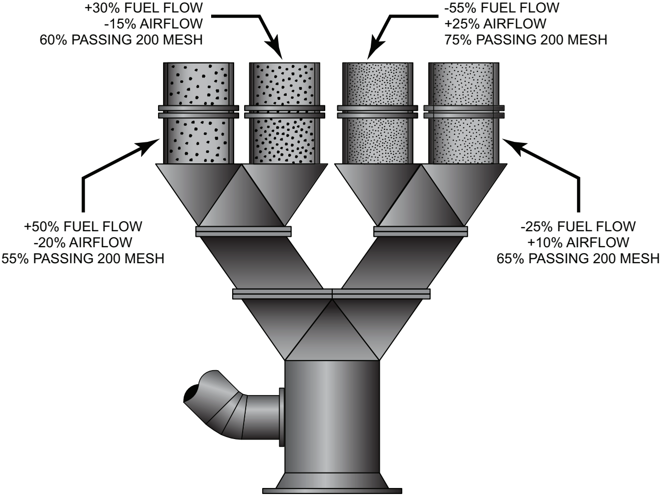
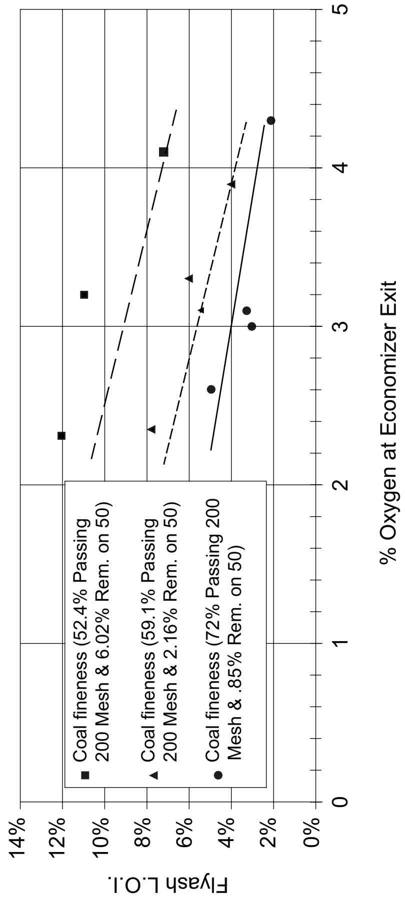


Figure 19-1 – Typical Effects of Coal Fineness on L.O.I.



Conversion Factors

TO OBTAIN	MULTIPLY	BY
Acres	Sq km	247.10
Acres	Sq miles	640.0
Area of circle	(Diam. Of circle)^2	0.7854
Area of sphere	(Diam. Of sphere)^2	3.1416
Atmospheres	Cm of Hg @ 0° C	0.013158
Atmospheres	Ft of H_2O @ 39.2° F	0.029499
Atmospheres	In. Hg @ 32° F	0.033421
Atmospheres	In. H_2O @ 39.2° F	0.0024583
Atmospheres	Pounds / sq ft	0.00047254
Atmospheres	Pounds / sq in	0.068046
Btu	Ft-lb	0.0012854
Btu	Hp-hr	2545.1
Btu	kWhr	3413.0
Btu	Whr	3.4130
Btu/hr	Mech. Hp	2545.1
Btu/hr	kW	3413.0
Btu/hr	Watts	3.4137
Btu/kw hr	Kg cal / kw hr	3.9685
Btu/min	Ft-lb / min	0.0012854
Btu/min	Mech hp	42.418
Btu/min	kW	56.896
Btu/sec	Mech hp	0.70696
Btu/sec	Mech hp (metric)	0.6971
Btu/sec	Kg-cal/hr	0.0011024
Btu/sec	kW	0.94827
Calories	Ft-lb	0.32389
Calories	Whr	860.01
Cal/gram	Btu/lb	0.55556
Centimeters	Inches	2.540
Cm of Hg @ 0° C	Atmospheres	76.0
Cm of Hg @ 0° C	Ft of H_2O @ 39.2° F	2.242
Cm of Hg @ 0° C	grams/sq cm	0.07356
Cm of Hg @ 0° C	In of H_2O @ 4° C	0.1868

TO OBTAIN	MULTIPLY	BY
Cm of Hg @ 0° C	Lb / sq in	5.1715
Cm of Hg @ 0° C	Lb / sq ft	0.035913
Cm/sec	Ft / min	0.508
Cm/sec	Ft / sec	30.48
Cm/(sec)(sec)	Gravity	980.665
Cm of H_2O @ 39.2° F	Atmospheres	1033.24
Cm of H_2O @ 39.2° F	Lb / sq in	70.31
Circumference of circle	Diameter of circle	3.1416
Circumferences	Radians	0.15916
Cu ft	Cu meters	35.314
Cu ft	Cu yards	27.0
Cu ft	Gal (USA, liq)	0.13368
Cu ft	Liters	0.03532
Cu ft / min	Cu meters / sec	2118.9
Cu ft / min	Gal (USA, liq / sec)	8.0192
Cu ft / lb	Cu meters / kg	16.02
Cu ft / lb	Liters / kg	0.01602
Cu ft / sec	Cu meters / min	0.5886
Cu ft / sec	Gal (USA, liq) / min	0.0022280
Cu ft / sec	Liters / min	0.0005886
Cu in	Cu centimeters	0.061023
Cu in	Gal (USA, liq)	231.0
Cu in	Liters	61.03
Cu meters	Cu ft	0.028317
Cu meters	Cu yards	0.7646
Cu meters	Gal (USA, liq)	0.0037854
Cu meters	Liters	0.001000028
Cu meters / hr	Gal / min	0.22712
Cu meters / kg	Cu ft / lb	0.062428
Cu meters / min	Cu ft / min	0.02832
Cu meters / min	Gal / sec	0.22712
Cu meters / sec	Gal / min	0.000063088
Cu yards	Cu meters	1.3079
Degrees of arc	Radians	57.296

TO OBTAIN	MULTIPLY	BY
Feet	Meters	0.3048
Ft of H_2O @ 39.2° F	Atmospheres	33.899
Ft of H_2O @ 39.2° F	Cm of Hg @ 0° C	0.44604
Ft of H_2O @ 39.2° F	In of Hg @ 32° F	1.1330
Ft of H_2O @ 39.2° F	Lb / sq ft	0.016018
Ft of H_2O @ 39.2° F	Lb / sq in	2.3066
Ft / min	Cm / sec	1.9685
Ft / min	Km / hr	54.68
Ft / min	Miles (USA, statute) hr	88.0
Ft / sec	Km / hr	0.9113
Ft / sec	Meters / sec	3.2808
Ft / sec	Miles (USA, statute) hr	1.4667
Ft / sec^2	Gravity (sea level)	32.174
Ft / sec^2	Km / (hr)(sec)	0.91133
Ft / sec^2	Meters / sec^2	3.2808
Ft-lb	Btu	778.0
Ft-lb	Kg – meters	7.233
Ft-lb	Kw – hr	2,655,200
Ft-lb	Mech. hp – hr	1,980,000
Ft-lb / min	Btu / min	778.0
Ft-lb / min	Kg cal / min	3087.4
Ft-lb / min	Kw	44,254.0
Ft-lb / min	Mech. hp	33,000
Ft-lb / sec	Btu / min	12.96
Ft-lb / sec	Kw	737.56
Ft-lb / sec	Mech. hp	550.0
Gal (USA, liq)	Barrels (petroleum, USA)	42
Gal (USA, liq)	Cu ft	7.4805
Gal (USA, liq)	Cu meters	264.173
Gal (USA, liq)	Cu yards	202.2
Gal (USA, liq)	Gal (Imperial, liq)	1.2010
Gal (USA, liq)	Liters	0.2642
Gal (USA, liq)/min	Cu ft / sec	448.83
Gal (USA, liq)/min	Cu meters / hr	4.4029

TO OBTAIN	MULTIPLY	BY
Gal (USA, liq)/sec	Cu ft / min	0.12468
Gal (USA, liq)/sec	Liters / min	0.0044028
Grams	Ounces (avoir)	28.350
Grams	Pounds (avoir)	453.5924
Grams / cm	Pounds / in	178.579
Grams / cu cm	Lb / cu ft	0.016018
Grams / cu cm	Lb / cu in	27.680
Grams / cu cm	Lb / gal	0.119826
Gravity (at sea level)	(ft / sec^2)	0.03108
Inches	Centimeters	0.3937
Inches of Hg @ 32° F	Atmospheres	29.921
Inches of Hg @ 32° F	Ft of H_2O @ 39.2° F	0.88265
Inches of Hg @ 32° F	Kg / sq meter	0.0028959
Inches of Hg @ 32° F	Lb / sq in	2.0360
Inches of Hg @ 32° F	Inches of H_2O @ 4° C	0.07355
Inches of H_2O @ 4° C	Inches of Hg @ 32° F	13.60
Inches of H_2O @ 39.2° F	Lb / sq in	27.673
Kg	Pounds (avour)	0.45359
Kg – cal	Btu	0.2520
Kg – cal	Ft – lb	0.00032389
Kw	Btu / min	0.01758
Kw	Ft – lb / min	0.00002259
Kw	Ft – lb / sec	0.00135582
Kw	Mech hp	0.7457
Kw – hr	Btu	0.000293
Kw – hr	Ft – lb	0.0000003766
Kw – hr	Mech hp – hr	0.7457
Liters	Gal (USA, liq)	3.78533
Mech hp	Btu / hr	0.0003929
Mech hp	Btu – min	0.023575
Mech hp	Ft – lb / sec	0.0018182
Mech hp	Kw	1.3410
Mech hp – hr	Btu	0.00039292
Mech hp – hr	Ft – lb	0.00000050505

TO OBTAIN	MULTIPLY	BY
Mech hp – hr	Kw – hr	1.3410
Meters	Feet	0.3048
Meters	Inches	0.0254
Meters	Miles (USA, statute)	1609.34
Meters /min	Ft / min	0.3048
Meters /min	Miles (USA, statute) / hr	26.82
Meters / sec	Ft / sec	0.3048
Meters / sec^2	Ft / sec^2	0.3048
Ounces (avoir)	Grams	0.035274
Ounces (USA, liq)	Gal (USA, liq)	128.0
Pounds (avoir)	Grams	0.0022046
Pounds / cu ft	Pounds / gal	7.48
Pounds / cu in	Grams / cu cm	0.036127
Pounds / inch	Grams / cm	0.0056
Pounds / sq inch	Atmospheres	14.696
Pounds / sq inch	Cm of hg @ 0° C	0.19337
Pounds / sq inch	Ft of H_2O @ 39.2° F	0.43352
Pounds / sq inch	In Hg @ 32° F	0.491
Pounds / sq inch	In H2O @ 39.2° F	0.0361
Pounds / sq inch	Kg / sq cm	14.223
Pounds / sq ft	Kg / sq meter	0.20481
Pounds / sq inch	Kg / sq meter	0.0014223
Pounds / gal (USA, liq)	Kg / liter	8.3452
Pounds / gal (USA, liq)	Pounds / cu ft	0.1337
Pounds / gal (USA, liq)	Pounds / cu in	231
Quarts (USA, liq)	Cu cm	0.0010567
Quarts (USA, liq)	Cu in	0.01732
Quarts (USA, liq)	Liters	1.057
Radians	Degrees of arc	0.017453
Sq inches	Circular inches	0.7854
Sq inches	Circular mils	0.0000007854
Volume of sphere	(Diameter of sphere)	30.5236
Watts	Btu / sec	1054.8
Yards	Meters	1.0936

Steel Pipe Dimensions and Weights

Nominal Size & OD Inches	Schedule Numbers (1) a-b-c	Wall Thickness Inches	Inside Diameter	Pipe Weight lbs/ft
	…-…-10S	0.049	0.307	0.18
0.125 (1/8)	40-STD-40S	0.068	0.269	0.24
0.405	80-XS-80S	0.095	0.215	0.31
	…-…-10S	0.065	0.410	0.33
0.25 (1/4)	40-STD-40S	0.088	0.364	0.42
0.540	80-XS-80S	0.119	0.302	0.54
	…-…-5S	0.049	0.710	0.33
0.375 (3/8)	…-…-10S	0.065	0.545	0.42
0.675	40-STD-40S	0.091	0.493	0.57
	80-XS-80S	0.126	0.423	0.74
	…-…-5S	0.065	0.710	0.53
	…-…-10S	0.083	0.674	0.67
0.50 (1/2)	40-STD-40S	0.109	0.622	0.85
0.840	80-XS-80S	0.147	0.546	1.08
	160-…-…	0.187	0.466	1.30
	…XXS-…	0.294	0.252	1.71
	…-…-5S	0.065	0.920	0.68
	…-…-10S	0.083	0.884	0.85
0.75 (3/4)	40-STD-40S	0.113	0.824	1.13
1.050	80-XS-80S	0.154	0.742	1.47
	160-…-…	0.219	0.612	1.93
	XXS-…	0.308	0.434	2.44
	…-…-5S	0.065	1.185	0.86
	…-…-10S	0.109	1.097	1.40
1	40-STD-40S	0.133	1.049	1.67
1.315	80-XS-80S	0.179	0.957	2.17
	160-…-…	0.250	0.815	2.84
	…XXS-…	0.358	0.599	3.65
	…-…-5S	0.065	1.530	1.10
	…-…-10S	0.109	1.442	1.80
1.250 (1 1/4)	40-STD-40S	0.140	1.380	2.27
1.660	80-XS-80S	0.191	1.278	2.99
	160-…-…	0.250	1.160	3.76
	…XXS-…	0.382	0.896	5.21
	…-…-5S	0.065	1.770	1.27
	…-…-10S	0.109	1.682	2.08
	40-STD-40S	0.145	1.610	2.71
1.5 (1 1/2)	80-XS-80S	0.200	1.500	3.63
1.900	160-…-…	0.281	1.338	4.85
	…XXS-…	0.400	1.100	6.40
	…-…-…	0.525	0.850	7.71
	…-…-…	0.650	0.600	8.67
	…-…-5S	0.065	2.245	1.60
	…-…-10S	0.109	2.157	2.63
	40-STD-40S	0.154	2.067	3.65
2	80-XS-80S	0.218	1.939	5.02
2.375	160-…-…	0.343	1.687	7.44
	…XXS-…	0.436	1.503	9.02
	…-…-…	0.562	1.251	11.00
	…-…-…	0.687	1.001	12.00

Nominal Size & OD Inches	Schedule Numbers (1) a-b-c	Wall Thickness Inches	Inside Diameter	Pipe Weight lbs/ft
2.5 2.875	…-…-5S	0.083	2.709	2.0
	…-…-10S	0.120	2.635	3.5
	40-STD-40S	0.203	2.469	5.8
	80-XS-80S	0.276	2.323	7.7
	160-…-…	0.375	2.125	10.0
	…XXS-…	0.552	1.771	14.0
	…-…-…	0.675	1.525	16.0
	…-…-…	0.800	1.275	18.0
3 3.500	…-…-5S	0.083	3.334	3.0
	…-…-10S	0.120	3.260	4.3
	40-STD-40S	0.216	3.068	7.6
	80-XS-80S	0.300	2.900	10.2
	160-…-…	0.437	2.626	14.3
	…XXS-…	0.600	2.300	19.0
	…-…-…	0.725	2.050	21.0
	…-…-…	0.850	1.800	24.0
3.5 4.000	…-…-5S	0.083	3.834	3.5
	…-…-10S	0.120	3.760	5.0
	40-STD-40S	0.226	3.548	9.1
	80-XS-80S	0.318	3.364	12.0
	…XXS-…	0.636	2.728	23.0
4 4.500	…-…-5S	0.083	4.334	3.9
	…-…-10S	0.120	4.260	5.6
	…-…-…	0.188	4.124	8.6
	40-STD-40S	0.237	4.026	11.0
	80-XS-80S	0.337	3.826	15.0
	120-…-…	0.437	3.626	19.0
	…-…-…	0.500	3.500	21.0
	160-…-…	0.531	3.438	23.0
	…XXS-…	0.674	3.152	28.0
	…-…-…	0.800	2.900	32.0
	…-…-…	0.925	2.650	35.0
5 5.563	…-…-5S	0.109	5.345	6.3
	…-…-10S	0.134	5.295	7.8
	40-STD-40S	0.258	5.047	15.0
	80-XS-80S	0.375	4.813	21.0
	120-…-…	0.500	4.563	27.0
	160-…-…	0.625	4.313	33.0
	…XXS-…	0.750	4.063	38.0
	…-…-…	0.875	3.813	44.0
	…-…-…	1.000	3.563	48.0
6 6.625	…-…-5S	0.109	6.407	5.4
	…-…-10S	0.134	6.357	9.3
	…-…-…	0.219	6.187	15.0
	40-STD-40S	0.280	6.065	19.0
	80-XS-80S	0.432	5.761	28.0
	120-…-…	0.562	5.501	36.0
	160-…-…	0.718	5.189	45.0
	…XXS-…	0.864	4.897	53.0
	…-…-…	1.000	4.625	60.0
	…-…-…	1.125	4.375	66.0

Nominal Size & OD Inches	Schedule Numbers $^{(1)}$ a-b-c	Wall Thickness Inches	Inside Diameter	Pipe Weight lbs/ft
8 8.625	…-…-5S	0.109	8.407	9.9
	…-…-10S	0.148	8.329	13
	…-…-…	0.219	8.187	20
	20-…-…	0.250	8.125	22
	30-…-…	0.277	8.071	25
	40-STD-40S	0.322	7.981	29
	60-…-…	0.406	7.813	36
	80-XS-80S	0.500	7.625	43
	100-…-…	0.593	7.439	51
	120-…-…	0.718	7.189	61
	140-…-…	0.812	7.001	68
	160-…-…	0.906	6.813	75
	…-…-…	1.000	6.625	81
	…-…-…	1.125	6.375	90
10 10.750	…-…-5S	0.134	10.482	15
	…-…-10S	0.165	10.420	19
	…-…-…	0.219	10.312	25
	20-…-…	0.250	10.250	28
	30-…-…	0.307	10.136	34
	40-STD-40S	0.365	10.020	40
	60-XS-80S	0.500	9.750	55
	80-…-…	0.593	9.564	64
	100-…-…	0.718	9.314	77
	120-…-…	0.843	9.064	89
	…-…-…	0.875	9.000	92
	140-…-…	1.000	8.750	104
	160-…-…	1.125	8.500	116
	…-…-…	1.250	8.250	127
	…-…-…	1.500	7.750	148
12 12.750	…-…-5S	0.156	12.438	21
	…-…-10S	0.180	12.390	24
	20-…-…	0.250	12.250	33
	30-…-…	0.330	12.090	44
	…STD-40S	0.375	12.000	50
	40-…-…	0.406	11.938	54
	…-XS…80S	0.500	11.750	65
	60-…-…	0.562	11.626	73
	80-…-…	0.687	11.376	89
	…-…-…	0.750	11.250	96
	100-…-…	0.843	11.064	107
	…-…-…	0.875	11.000	111
	120-…-…	1.000	10.750	125
	140-…-…	1.125	10.500	140
	…-…-…	1.250	10.250	154
	160-…-…	1.312	10.126	160

Nominal Size & OD Inches	Schedule Numbers (1) a-b-c	Wall Thickness Inches	Inside Diameter	Pipe Weight lbs/ft
14 14.000	…-…-5S	0.156	13.688	23
	…-…-10S	0.188	13.624	28
	…-…-…	0.210	13.580	31
	…-…-…	0.219	13.562	32
	10-…-…	0.250	13.500	37
	…-…-…	0.281	13.438	41
	20-…-…	0.312	13.376	46
	…-…-…	0.344	13.312	50
	30-STD-…	0.375	13.250	55
	40-…-…	0.437	13.126	63
	…-…-…	0.469	13.062	68
	…-XS-…	0.500	13.000	72
	60-…-…	0.593	12.814	85
	…-…-…	0.625	12.750	89
	80-…-…	0.750	12.500	106
	100-…-…	0.937	12.126	131
	120-…-…	1.093	11.814	151
	140-…-…	1.250	11.500	170
	160-…-…	1.406	11.188	189
16 16.000	…-…-5S	0.165	15.670	28
	…-…-10S	0.188	15.624	32
	10-...-…	0.250	15.500	42
	20-…-…	0.312	15.376	52
	30-STD-…	0.375	15.250	63
	40-XS-…	0.500	15.000	83
	60-…-…	0.656	14.688	107
	80-…-…	0.843	14.314	136
	100-…-…	1.031	13.938	165
	120-…-…	1.218	13.564	162
	140-…-…	1.437	13.126	224
	160-…-…	1.593	12.814	245
18 18.000	…-…-5S	0.165	17.670	31
	…-…-10S	0.188	17.624	36
	10-…-…	0.250	17.500	47
	20-…-…	0.312	17.376	59
	…STD-…	0.375	17.250	71
	30-…-…	0.437	17.126	82
	…-XS-…	0.500	17.000	93
	40-…-…	0.562	16.876	105
	60-…-…	0.750	16.500	138
	80-…-…	0.937	16.126	171
	100-…-…	1.156	15.688	208
	120-…-…	1.375	15.250	244
	140-…-…	1.562	14.876	274
	160-…-…	1.781	14.438	308

Nominal Size & OD Inches	Schedule Numbers $^{(1)}$ a-b-c	Wall Thickness Inches	Inside Diameter	Pipe Weight lbs/ft
20 20.000	…-…-5S	0.188	19.634	40
	…-…-10S	0.218	19.564	46
	10-…-…	0.250	19.500	53
	20-STD-…	0.375	19.250	79
	30-XS-…	0.500	19.000	104
	40-…-…	0.593	18.814	123
	60-…-…	0.812	18.376	166
	…-…-…	0.875	18.250	179
	80-…-…	1.031	17.938	209
	100-…-…	1.281	17.438	256
	120-…-…	1.500	17.000	296
	140-…-…	1.750	16.500	341
	160-…-…	1.968	16.064	379
22 22.000	…-…-5S	0.188	21.624	44
	…-…-10S	0.218	21.564	51
	10-…-…	0.250	21.500	58
	20-STD-…	0.375	21.250	87
	30-XS-…	0.500	21.000	115
	…-…-…	0.625	20.750	143
	…-…-…	0.750	20.500	170
	60-…-…	0.875	20.250	197
	80-…-…	1.125	19.750	251
	100-…-…	1.375	19.250	303
	120-…-…	1.625	18.750	354
	140-…-…	1.875	18.250	403
	160-…-…	2.125	17.750	451
24 24.000	…-…-5S	0.218	23.564	55
	10-…-…	0.250	23.500	63
	20-STD-…	0.375	23.250	95
	…-XS-…	0.500	22.000	125
	30-…-…	0.562	22.876	141
	…-…-…	0.625	22.750	156
	40-…-…	0.687	22.626	171
	…-…-…	0.750	22.500	186
	…-…-…	0.875	22.250	216
	60-…-…	0.968	22.064	238
	80-…-…	1.218	21.564	296
	100-…-…	1.531	20.938	367
	120-…-…	1.812	20.376	429
	140-…-…	2.062	19.876	483
	160-…-…	2.343	19.314	542
26 26.000	…-…-…	0.250	25.500	67
	10-…-…	0.312	25.376	86
	…-STD-…	0.375	25.250	103
	20-XS-…	0.500	25.000	136
	…-…-…	0.625	24.750	169
	…-…-…	0.750	24.500	202
	…-…-…	0.875	24.250	235
	…-…-…	1.000	24.000	267
	…-…-…	1.125	23.750	299
	…-…-…	0.250	27.500	74

Nominal Size & OD Inches	Schedule Numbers (1) a-b-c	Wall Thickness Inches	Inside Diameter	Pipe Weight lbs/ft
28 28.000	10-…-…	0.312	27.376	92
	…-STD-…	0.375	27.250	111
	20-XS-…	0.500	27.000	147
	30-...-…	0.625	26.750	183
	…-…-…	0.750	26.500	218
	…-…-…	0.875	26.250	253
	…-…-…	1.000	26.000	288
	…-…-…	1.125	25.750	323
30 30.000	…-…-5S	0.250	29.500	79
	10-…-10S	0.312	29.376	99
	…-STD-…	0.375	29.250	119
	20-XS-…	0.500	29.000	158
	30-...-…	0.625	28.750	196
	40-…-…	0.750	28.500	234
	…-…-…	0.875	28.250	272
	…-…-…	1.000	28.000	310
	…-…-…	1.125	27.750	347
32 32.000	…-…-…	0.250	31.500	85
	10-…-…	0.312	31.376	106
	...-STD-…	0.375	31.250	127
	20-XS-…	0.500	31.000	168
	30-…-…	0.625	30.750	209
	40-…-…	0.688	30.624	230
	…-…-…	0.750	30.500	250
	…-…-…	0.875	30.250	291
	…-…-…	1.000	30.000	331
	…-…-…	1.125	29.750	371
34 34.000	…-…-…	0.250	33.500	90
	10-…-…	0.312	33.376	112
	…-STD-…	0.375	33.250	135
	20-XS-…	0.500	33.000	179
	30-…-…	0.625	32.750	223
	40-…-…	0.688	32.624	245
	…-…-…	0.750	32.500	266
	…-…-…	0.875	32.250	310
	…-…-…	1.000	32.000	353
	…-…-…	1.125	31.750	395
36 36.000	…-…-…	0.250	35.500	96
	10-…-…	0.312	35.376	119
	…-STD-…	0.375	35.250	143
	20-XS-…	0.500	35.000	190
	30-…-…	0.625	34.750	236
	40-…-…	0.750	34.500	282
	…-…-…	0.875	34.250	328
	…-…-…	1.000	34.000	374
	…-…-…	1.125	33.750	419
42 42.000	…-…-…	0.250	41.500	112
	…-STD-…	0.375	41.250	167
	20-XS-…	0.500	41.000	222
	30-…-…	0.625	40.750	276
	40-…-…	0.750	40.500	330
	…-…-…	1.000	40.000	438
	…-…-…	1.250	39.500	544
	…-…-…	1.500	39.000	649

Steel Gauges and Weights

Table of Guages and Weights

	Steel		Galvanized Steel		Stainless Steel		
						Chrome Alloy	Chrome Nickel
Gauge	Decimal Thickness (inches)	Pounds per Sq Ft	Decimal Thickness (inches)	Pounds per Sq Ft	Decimal Thickness (inches)	Pounds per Sq Ft	Pounds per Sq Ft
32	0.0097	0.408	0.0134	0.547	0.0102	0.371	0.378
31	0.0105	0.449	0.0142	0.594	0.0109	0.412	0.420
30	0.0120	0.500	0.0157	0.656	0.0125	0.495	0.504
29	0.0135	0.563	0.0172	0.719	0.0141	0.536	0.546
28	0.0149	0.625	0.0187	0.781	0.0156	0.599	0.610
27	0.0164	0.688	0.0202	0.844	0.0172	0.660	0.672
26	0.0179	0.750	0.0217	0.906	0.0187	0.736	0.750
25	0.0209	0.875	0.0247	1.031	0.0219	0.866	0.882
24	0.0239	1.000	0.0276	1.156	0.0250	0.972	0.990
23	0.0269	1.125	0.0306	1.281	0.0281	1.072	1.092
22	0.0299	1.250	0.0336	1.406	0.0312	1.197	1.220
21	0.0329	1.375	0.0366	1.531	0.0344	1.319	1.344
20	0.0359	1.500	0.0396	1.656	0.0375	1.462	1.490
19	0.0418	1.750	0.0456	1.906	0.0437	1.731	1.794
18	0.0478	2.000	0.0516	2.156	0.0500	1.979	2.016
17	0.0538	2.250	0.0575	2.406	0.0562	2.226	2.268
16	0.0598	2.500	0.0635	2.656	0.0625	2.454	2.500
15	0.0673	2.813	0.0710	2.969	0.0703	2.762	2.814
14	0.0747	3.125	0.0785	3.281	0.0781	3.047	3.150
13	0.0897	3.750	0.0934	3.906	0.0937	3.710	3.780
12	0.1046	4.375	0.1084	4.531	0.1094	4.328	4.410
11	0.1196	5.000	0.1233	5.156	0.1250	4.946	5.040
10	0.1345	5.625	0.1382	5.781	0.1406	5.523	5.628
9	0.1495	6.250	0.1532	6.406	0.1562	6.183	6.300
8	0.1644	6.875	0.1681	7.031	0.1719	6.801	6.930
7	0.1793	7.500			0.1875	7.708	7.854
3/16"	0.1875	7.660					8.579
1/4"	0.2500	10.210				11.160	11.160
5/16"	0.3125	12.760				15.750	13.750
3/8"	0.3750	15.320				15.970	16.500
1/2"	0.5000	20.320					21.660
5/8"	0.6250	25.530					26.830
3/4"	0.7500	30.630					32.120
1"	1.0000	40.800					42.670

Drill Sizes and Orifice Capacity

Drill Size or Diameter	Diameter in Inches	Area Sq Inches
80	0.0135	0.0001
79	0.0145	0.0002
1/64”	0.0156	0.0002
78	0.0160	0.0002
77	0.0180	0.0003
76	0.0200	0.0003
75	0.0210	0.0003
74	0.0225	0.0004
73	0.0240	0.0005
72	0.0250	0.0005
71	0.0260	0.0005
70	0.0280	0.0006
69	0.0292	0.0007
68	0.0310	0.0008
1/32”	0.0313	0.0008
67	0.0320	0.0008
66	0.0330	0.0009
65	0.0350	0.0010
64	0.0360	0.0010
63	0.0370	0.0011
62	0.0380	0.0011
61	0.0390	0.0012
60	0.0400	0.0013
59	0.0410	0.0013
58	0.0420	0.0014
57	0.0430	0.0015
56	0.0465	0.0017
3/64”	0.0469	0.0017
55	0.0520	0.0021
54	0.0550	0.0024
53	0.0595	0.0028
1/16”	0.0625	0.0031

Drill Size or Diameter	Diameter in Inches	Area Sq Inches
52	0.0635	0.0032
51	0.0670	0.0035
50	0.0700	0.0039
49	0.0730	0.0042
48	0.0760	0.0045
3/64”	0.0781	0.0048
47	0.0785	0.0048
46	0.0810	0.0052
45	0.0820	0.0053
44	0.0860	0.0058
43	0.0890	0.0062
42	0.0935	0.0069
3/32”	0.0937	0.0069
41	0.0960	0.0072
40	0.0980	0.0075
39	0.0995	0.0078
38	0.1015	0.0081
37	0.1040	0.0085
36	0.1065	0.0089
7/64”	0.1093	0.0094
35	0.1100	0.0095
34	0.1110	0.0097
33	0.1130	0.0100
32	0.1160	0.0106
31	0.1200	0.0113
1/8”	0.1250	0.0123
30	0.1285	0.0130
29	0.1360	0.0145
28	0.1450	0.0155
9/64”	0.1406	0.0155
27	0.1440	0.0163
26	0.1470	0.0170
25	0.1495	0.0176

Drill Size or Diameter	Diameter in Inches	Area Sq Inches
24	0.1520	0.0182
23	0.1540	0.0186
5/32”	0.1562	0.0192
22	0.1570	0.0194
21	0.1590	0.0197
20	0.1610	0.0204
19	0.1660	0.0216
18	0.1695	0.0226
11/64”	0.1719	0.0232
17	0.1750	0.0241
16	0.1770	0.0246
15	0.1800	0.0255
14	0.1820	0.0260
13	0.1830	0.0269
3/16”	0.1875	0.0276
12	0.1890	0.0281
11	0.1910	0.0287
10	0.1935	0.0294
9	0.1960	0.0302
8	0.1990	0.0311
7	0.2010	0.0317
13/64”	0.2301	0.0324
6	0.2040	0.0327
5	0.2055	0.0332
4	0.2090	0.0343
3	0.2130	0.0356
7/32”	0.2187	0.0376
2	0.2210	0.0384
1	0.2280	0.0408
A	0.2340	0.0430
15/64”	0.2343	0.0431
B	0.2380	0.0445
C	0.2420	0.0460

Drill Size or Diameter	Diameter in Inches	Area Sq Inches
D	0.2460	0.0475
1/4”	0.2500	0.0491
E	0.2500	0.0491
F	0.2570	0.0519
G	0.2610	0.0535
17/64”	0.2656	0.0554
H	0.2660	0.0556
I	0.2720	0.0581
J	0.2770	0.0603
K	0.2810	0.0620
9/32”	0.2812	0.0621
L	0.2900	0.0661
M	0.2950	0.0684
19/64”	0.2968	0.0692
N	0.3020	0.0716
5/16”	0.3125	0.0767
O	0.3160	0.0784
P	0.3230	0.0819
21/64”	0.3281	0.0846
Q	0.3320	0.0866
R	0.3390	0.0903
11/32”	0.3437	0.0928
S	0.3480	0.0951
T	0.3580	0.1007
23/64”	0.3593	0.1014
U	0.3680	0.1064
3/8”	0.3750	0.1105
V	0.3770	0.1116
W	0.3860	0.1170
25/64”	0.3906	0.1198
X	0.3970	0.1238
Y	0.4040	0.1282
13/32”	0.4062	0.1296

Drill Size or Diameter	Diameter in Inches	Area Sq Inches
Z	0.4130	0.1340
7/16”	0.4375	0.1503
29/64”	0.4531	0.1612
15/32”	0.4687	0.1725
31/64”	0.4843	0.1842
1/2”	0.5000	0.1964
33/64”	0.5156	0.2068
17/32”	0.5312	0.2216
35/64”	0.5468	0.2348
9/16”	0.5625	0.2485
37/64”	0.5781	0.2625
19/32”	0.5937	0.2768
39/64”	0.6093	0.2916
5/8”	0.6250	0.3068
41/64”	0.6506	0.3324
21/32”	0.6562	0.3382
43/64”	0.6781	0.3611
11/16”	0.6875	0.3712
45/64”	0.7031	0.3883
23/32”	0.7187	0.4057
47/64”	0.7343	0.4235
3/4”	0.7500	0.4418
49/64”	0.7656	0.4604
25/32”	0.7812	0.4793
51/64”	0.7968	0.4986
13/16”	0.8125	0.5185
53/64”	0.8281	0.5386
27/32”	0.8337	0.5459
55/64”	0.8593	0.5799
7/8”	0.8750	0.6013

Figure 20-1 – Instantaneous Specific Heat of Air

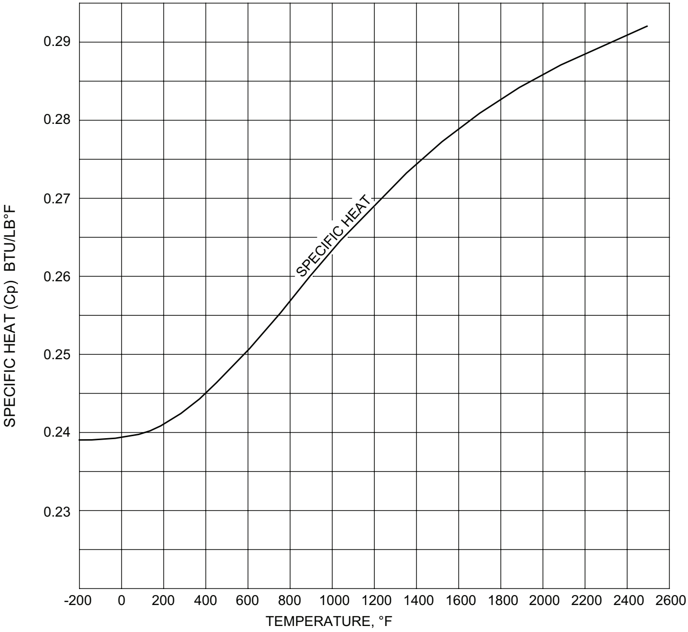


Figure 21-1 – Instantaneous Specific Heat of Dry Flue Gas

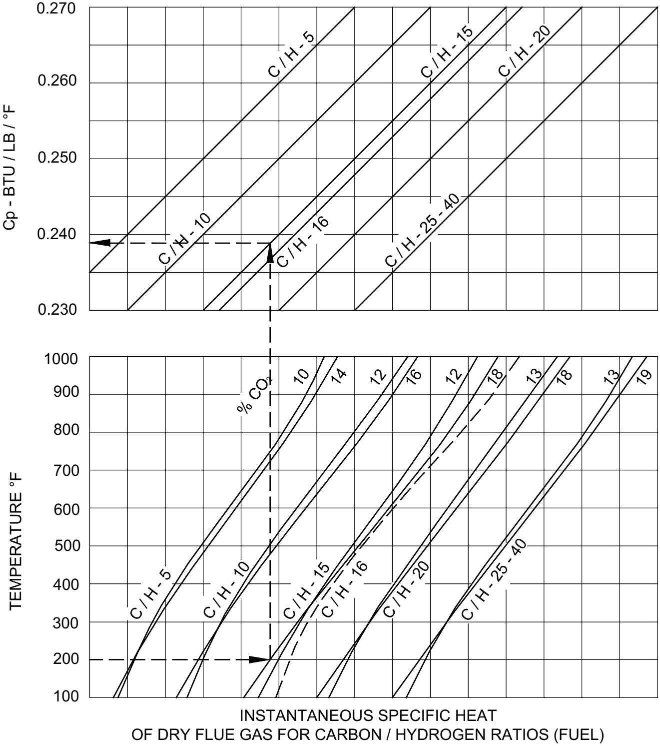
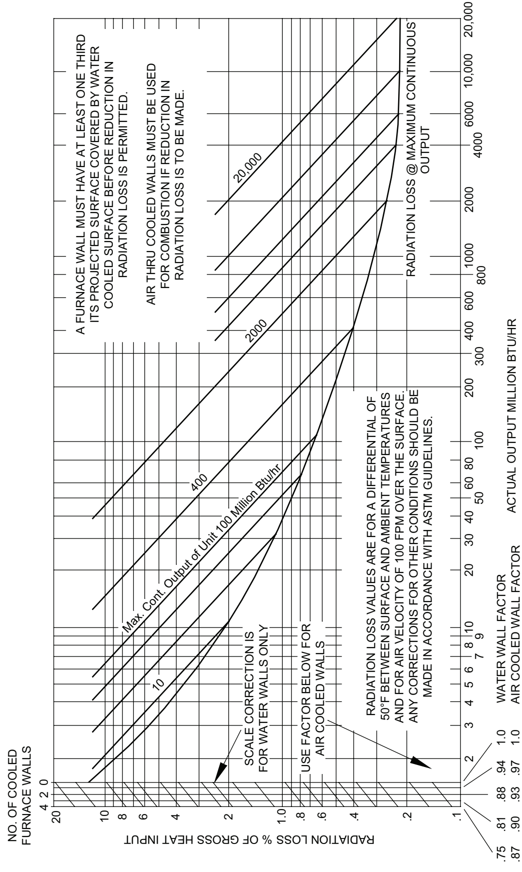


Figure 22-1 – Radiation Losses



A FURNACE WALL MUST HAVE AT LEAST ONE THIRD ITS PROJECTED SURFACE COVERED BY WATER COOLED SURFACE BEFORE REDUCTION IN RADIATION LOSS IS PERMITTED.

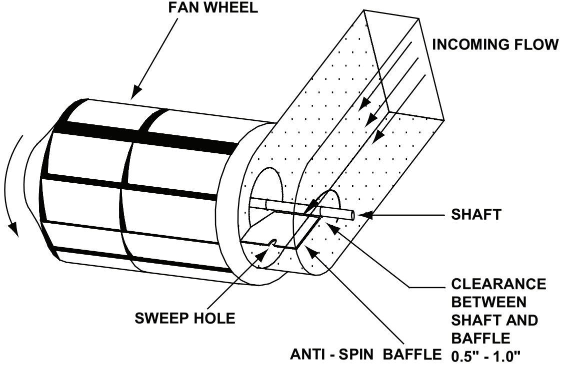
AIR THRU COOLED WALLS MUST BE USED FOR COMBUSTION IF REDUCTION IN RADIATION LOSS IS TO BE MADE.

SCALE CORRECTION IS FOR WATER WALLS ONLY

USE FACTOR BELOW FOR AIR COOLED WALLS

RADIATION LOSS VALUES ARE FOR A DIFFERENTIAL OF 50°F BETWEEN SURFACE AND AMBIENT TEMPERATURES AND FOR AIR VELOCITY OF 100 FPM OVER THE SURFACE. ANY CORRECTIONS FOR OTHER CONDITIONS SHOULD BE MADE IN ACCORDANCE WITH ASTM GUIDELINES.

Figure 23-1 – Anti-Spin Baffle Installation



ANTI-SPIN BAFFLE INSTALLATION

NOTES:

1) Anti-spin baffle fabricated from 0.375" C.S. plate mounted and welded to a 2" x 2" x 0.25" angle iron frame. Location of baffle is to be 180° from gas inlet.

2) This is a concept drawing. The specific application of an anti-spin baffle should be made by a Service Engineer following the taking of operating data and an internal fan inspection.

Figure 24-1 – Installation of Pre-Spin Vanes to Reduce Fan Capacity and Auxiliary Horsepower Consumption on an Oversized Fan

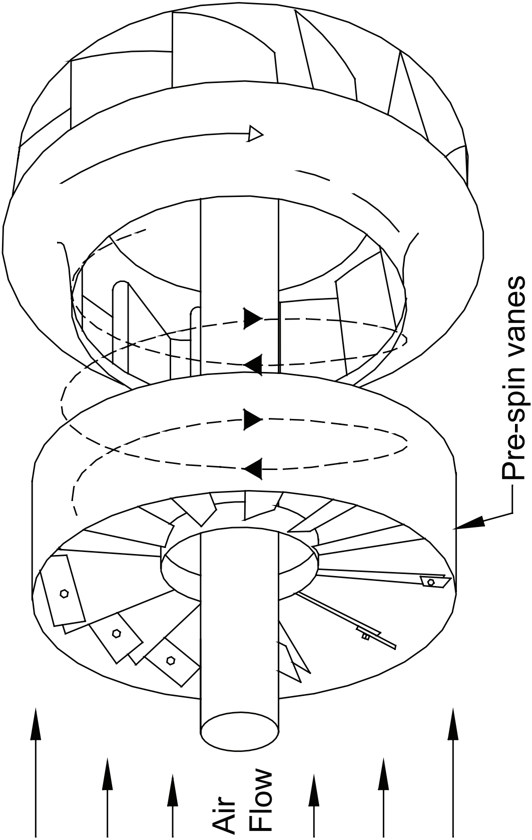


Figure 25-1 – Modification to Tighten Inlet Bell Clearance on a Fan

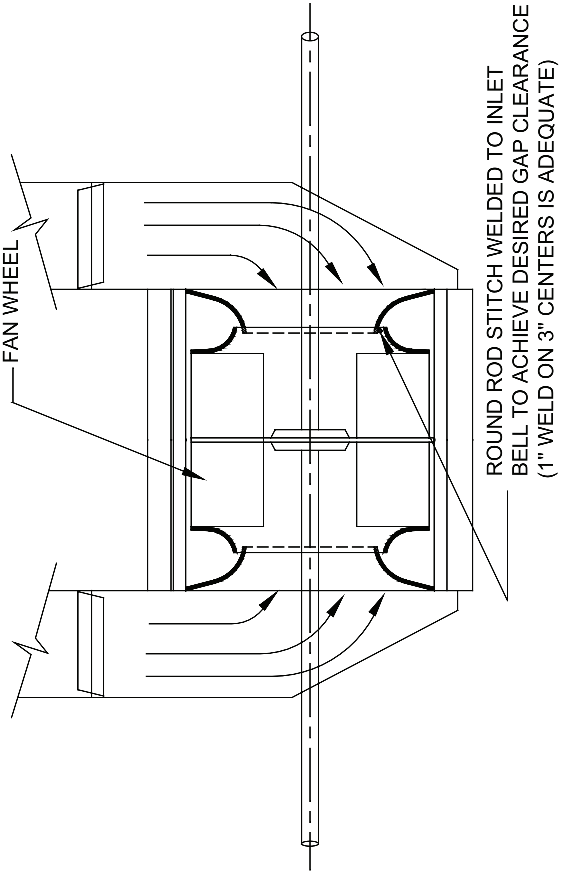
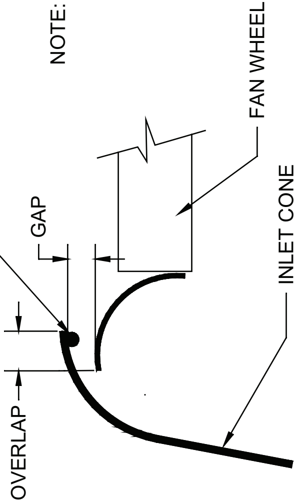


Figure 26-1 – Reducing Fan Bell Inlet Gap with Round Rod



ROUND ROD STITCH WELDED TO INLET BELL TO ACHIEVE DESIRED GAP CLEARANCE (1" WELD ON 3" CENTERS IS ADEQUATE)

NOTE: TACK WELD ROUND ROD TO INLET BELL AND BEND TO FIT DIAMETER STITCH WELD AS ROD IS BENT

Figure 27-1 – Verifying and Changing Blowing Pressure on an IR or IK Type Wall De-Slagger

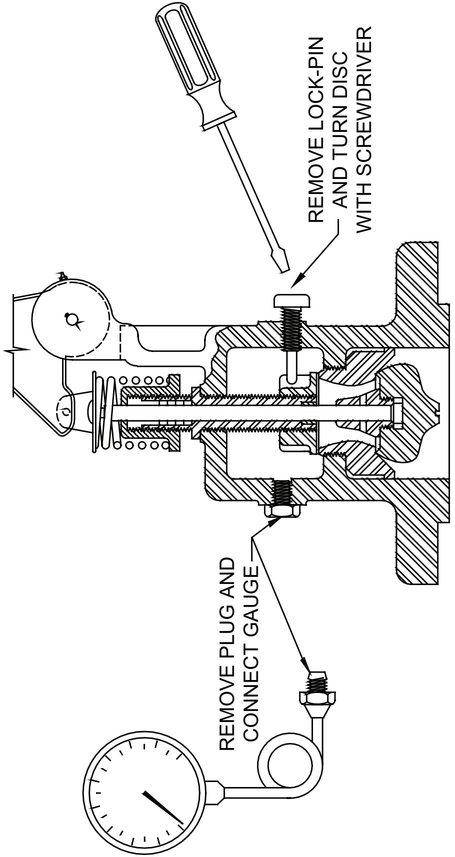


Figure 28-1 – Angled Blade Classifier Modification for Pulverizers with Fixed Classifier Blades

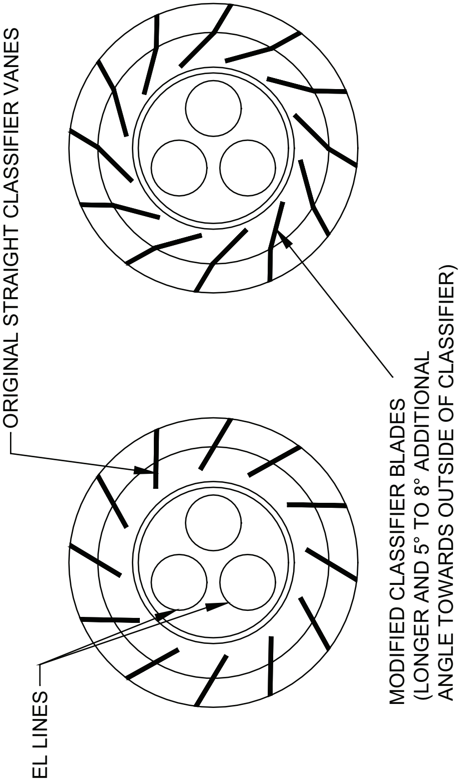
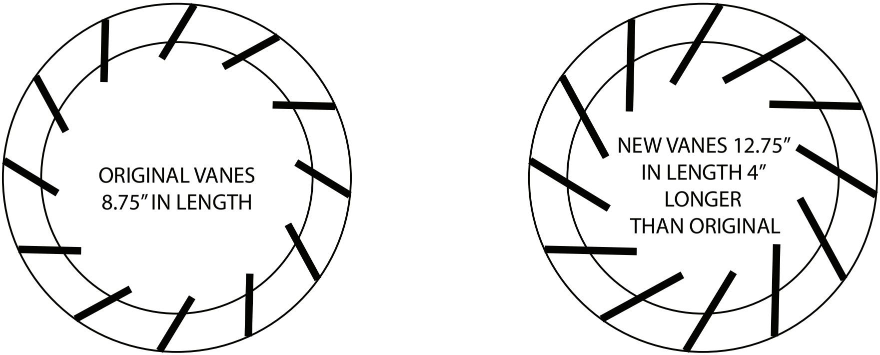


Figure 29-1 – Improvement in Pulverizer Fuel Balance with Extended Classifier Blades



PRE-MODIFICATION TESTING			POST-MODIFICATION TESTING	
DIRTY AIR VELOCITIES	RECOVERED SAMPLE (g)		DIRTY AIR VELOCITIES	RECOVERED SAMPLE (g)
+8.27%	+13.2%	MAXIMUM DEVIATION	+1.55%	+5.45%
-6.07%	-18.3%	MINIMUM DEVIATION	-2.33%	-6.05%

DEVIATIONS ARE % DEVIATION FROM MEAN VELOCITY OR RECOVERY WEIGHT

Figure 30-1 – Circulation of Coal through a Bowl Mill Classifier

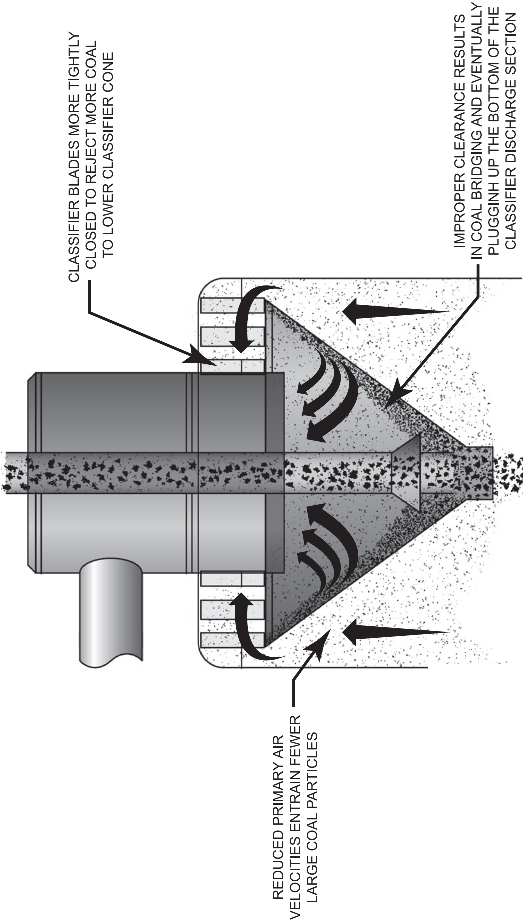


Figure 31-1 – Bowl Mill Air and Fuel Management

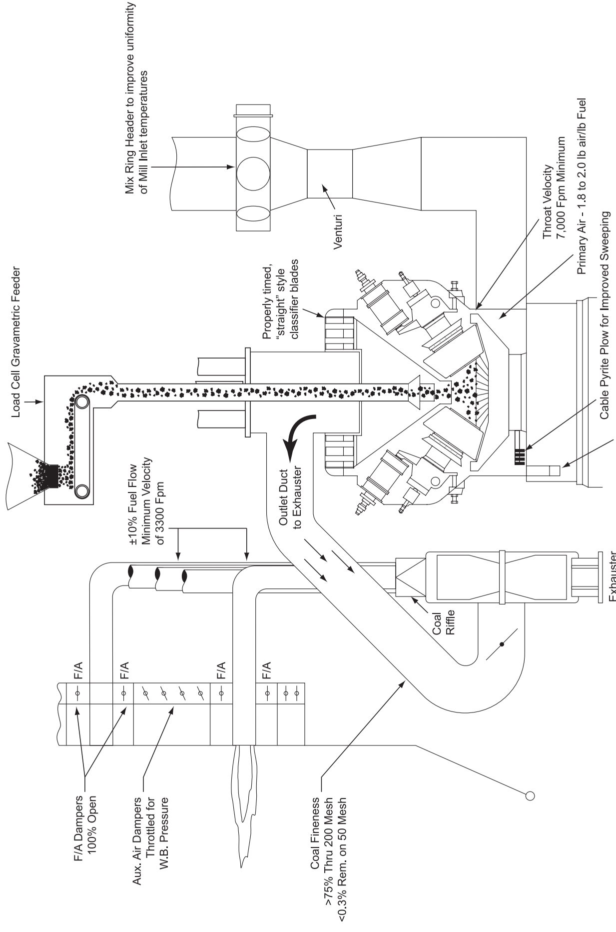


Figure 32-1 – Critical Mechanical Tolerances on Deep Bowl Pulverizers

Actual clearance will vary due to coal hardness, moisture, capacity and fineness requirements. Call a qualified consultant at ICT for tolerances specific to your installation.

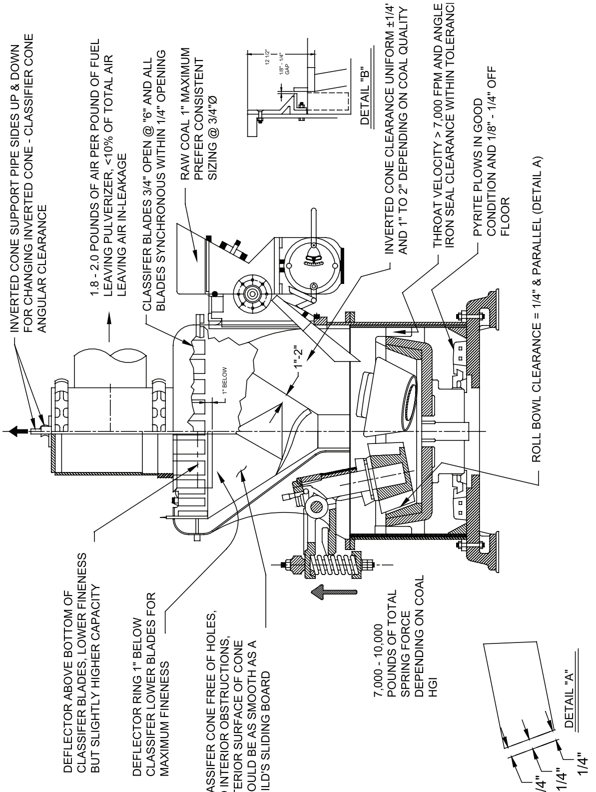
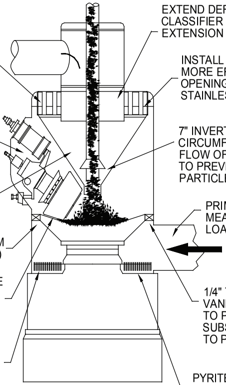


Figure 33-1 – Critical Mechanical Tolerances on a 983 RP Shallow Bowl Pulverizer

CRITICAL MECHANICAL TOLERANCES ON A 983 RPS SHALLOW BOWL PULVERIZER



CLASSIFIER BLADE TIMING WITHIN 1/4" WITH MECHANICAL STOPS INSTALLED, 1 3/4" OPENING AT POSITION "10" AND SHAFTS TACK WELDED

UNIFORM JOURNAL SPRING PRESSURE (±500 lbs.). JOURNAL SPRING PRESSURES SHOULD BE 38,000 - 40,000 lbs. FOR FINENESS AND CAPACITY, INCREASE SPRING PRESSURES TO 42,000 lbs. IF >75% AND <0.5% REMAINING ON 50 MESH CANNOT BE ACHIEVED FOLLOWING A PULVERIZER OVERHAUL

CERAMIC LINED INTERIOR TO MAINTAIN CLASSIFIER CONE INTEGRITY AND PREVENT FORMATION OF HOLES IN CONE (AIR TIGHT SEAL ON CLASSIFIER CONE ACCESS DOORS)

THROAT VELOCITIES SHOULD BE GREATER THAN 7,000 FPM TO MINIMIZE COAL REJECTS (PREFERABLY 4.5" THROAT)

JOURNAL ROLL TO BULLRING CLEARANCE PARALLEL WITH CLEARANCE 1/4" - 3/8" REPLACE OR RESURFACE JOURNAL IF CLEARANCE IS GREATER THAN 3/4"

ENSURE PYRITE CHUTE IS CLEAR OF DEBRIS

EXTEND DEFLECTOR TO 4" BELOW BOTTOM OF CLASSIFIER BLADES (SEAL WELD GAPS BETWEEN EXTENSION AND DEFLECTOR SEGMENTS)

INSTALL STRAIGHT CLASSIFIER BLADES FOR MORE EFFICIENT CLASSIFICATION AND FURTHER OPENING OF CLASSIFIER BLADES (400 SERIES STAINLESS 3/8" THICK AND 16" LONG

7" INVERTED CONE CLEARANCE (UNIFORM AROUND CIRCUMFERENCE) CLEARANCE WIDE ENOUGH FOR FREE FLOW OF COARSE REJECTS BUT ENOUGH RESTRICTION TO PREVENT PRIMARY AIR FROM ENTRAINING COARSE PARTICLES TO THE OUTLET PIPES

PRIMARY AIR FLOW MUST BE ACCURATELY MEASURED AND RAMPED FOR LOW PULVERIZER LOADING PERFORMANCE AND FLAME STABILITY

1/4" TO 3/8" KICKER SEAL CLEARANCE (KICKER SEAL - VANE WHEEL AND LOWER KICKER SEAL - MILL HOUSING) TO PREVENT REDUCTION IN THROAT VELOCITY AND SUBSEQUENT RAW COAL SPILLAGE, THIS SPILLAGE TO PYRITE SECTION CAN CAUSE UNDER - BOWL FIRES

PYRITE PLOW CLEARANCE 0 - 1/8" WITH TABLE (2) PLOWS INSTALLED 180° APART WITH WIRE CABLE TYPE ON ALL PULVERIZERS

Actual clearance will vary due to coal hardness, moisture, capacity and fineness requirements.
Call a qualified consultant at ICT for tolerances specific to your installation.

Figure 34-1 – Verifying Journal Spring Pressure on a Deep Bowl Mill

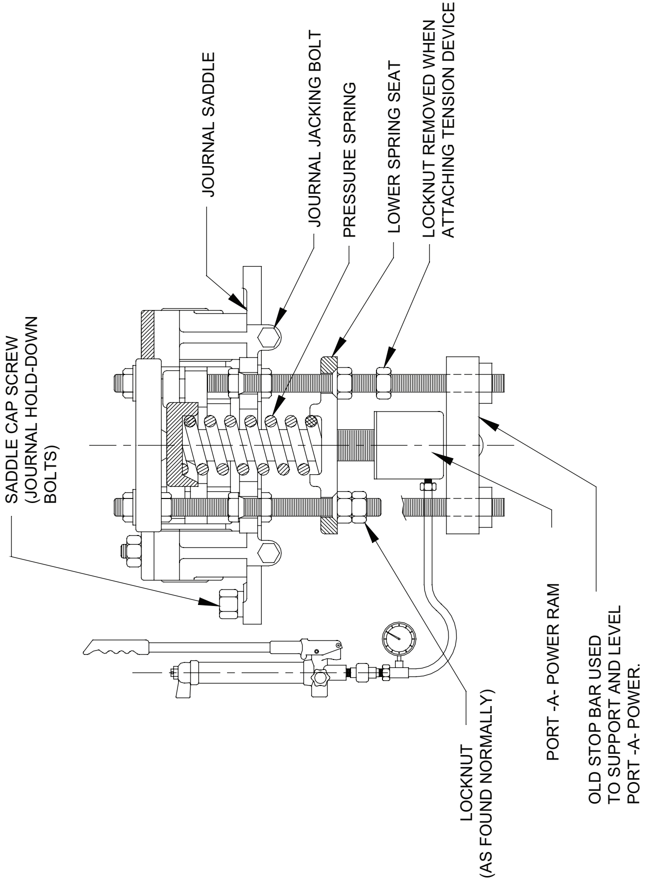


Figure 35-1 – Bowl Mill Journal Wear and Ring to Roll Clearances

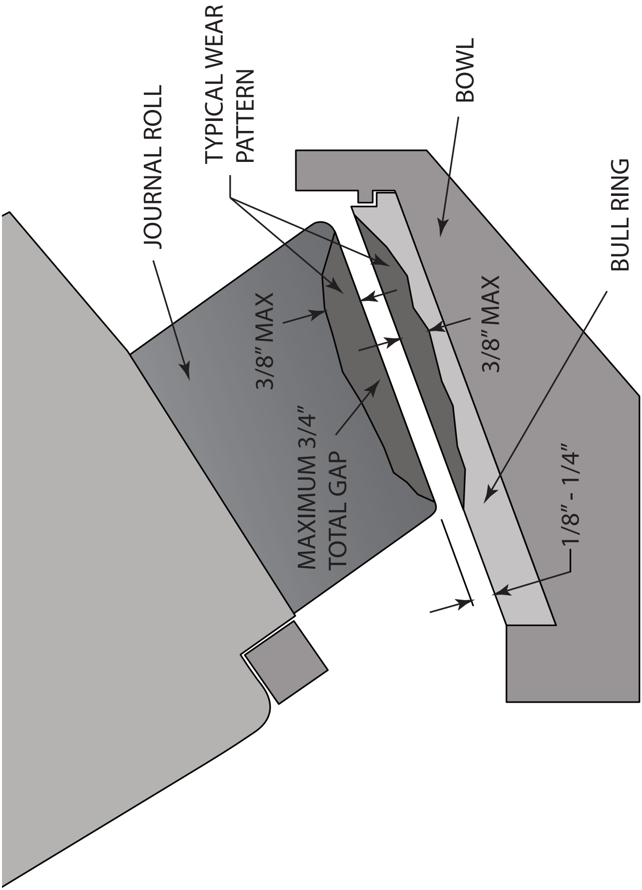


Figure 36-1 – Proper Velocity Through a Pulverizer Throat or Vane Wheel

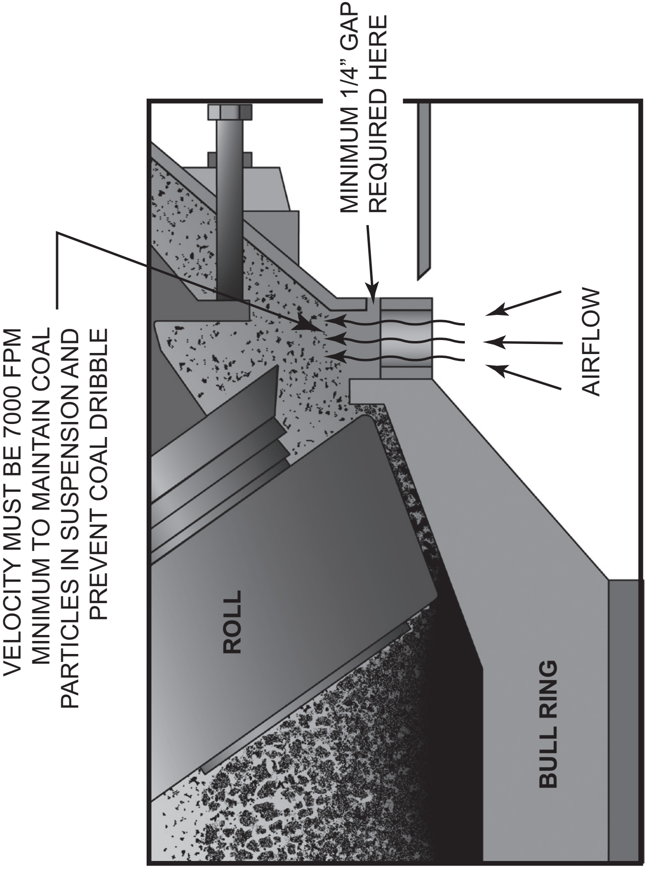


Figure 37-1 – Raw Coal Deflector for an EL Pulverizer

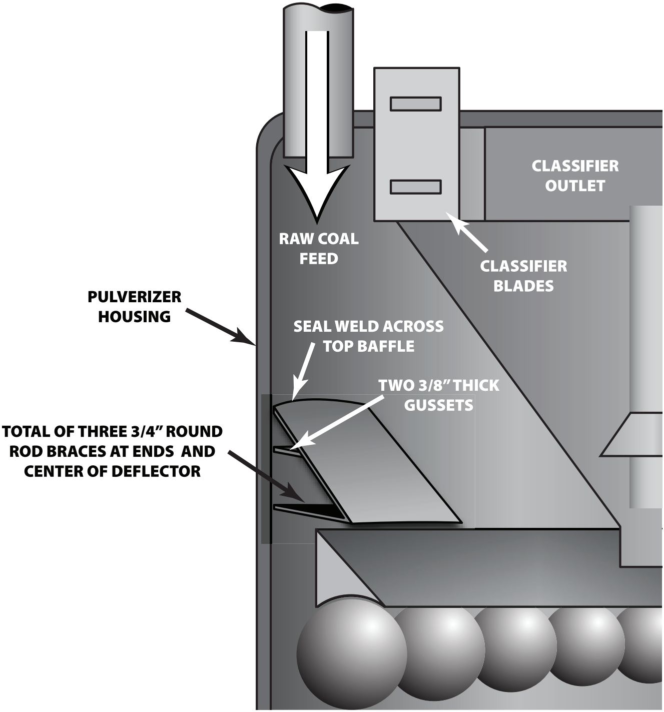


Figure 38-1 – Deflector Ring Modification to Improve Coal Fineness

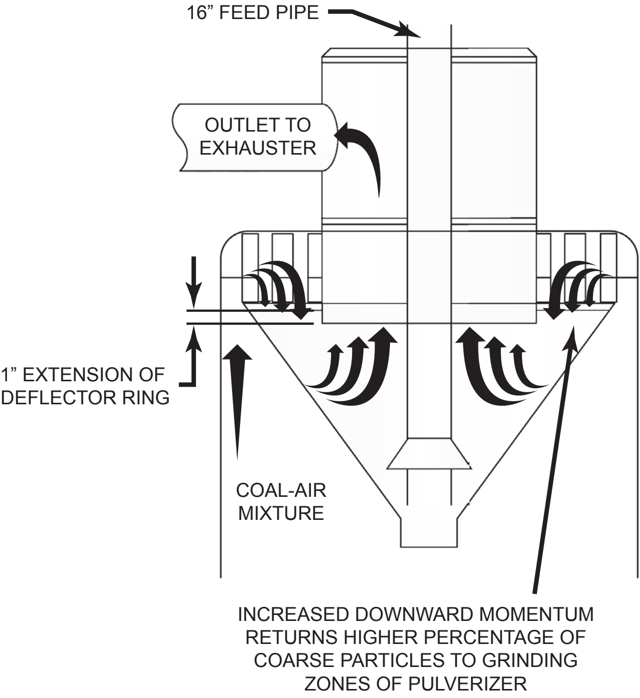


Figure 39-1 – Effect of Coal H.G.I on Pulverizer Capacity

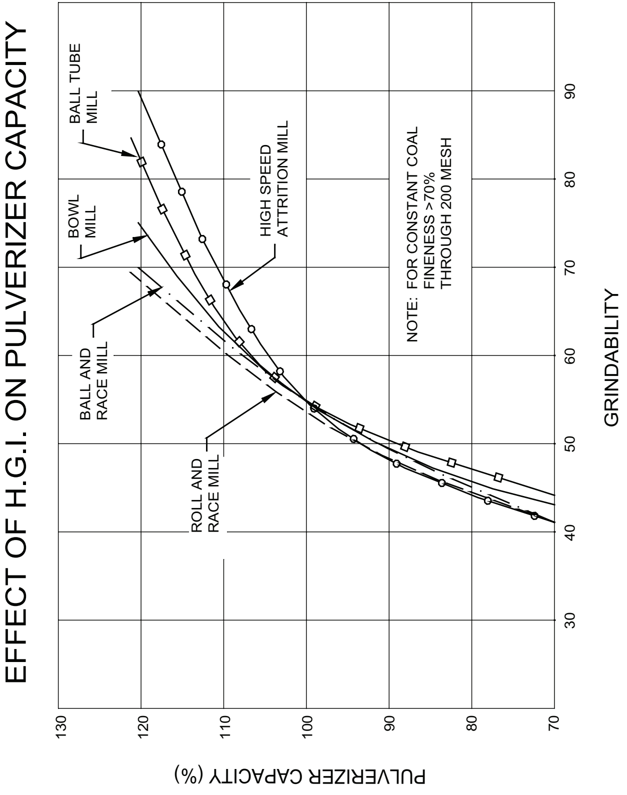


Figure 40-1 – Typical Effect of Grindability and Fineness on Milling Capacity of a Vertical Spindle Coal Pulverizer

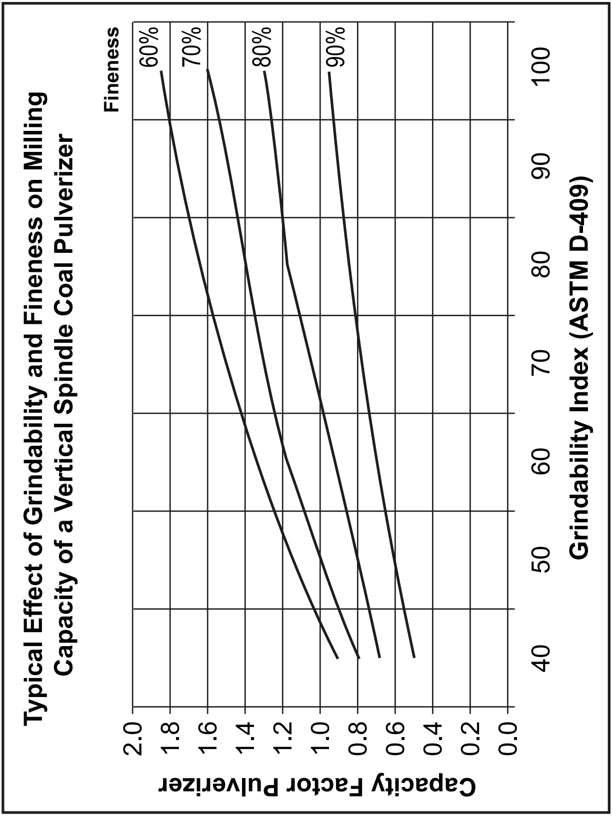


Figure 41-1 – Typical Variation in H.G.I. with Sub-Bituminous Coals

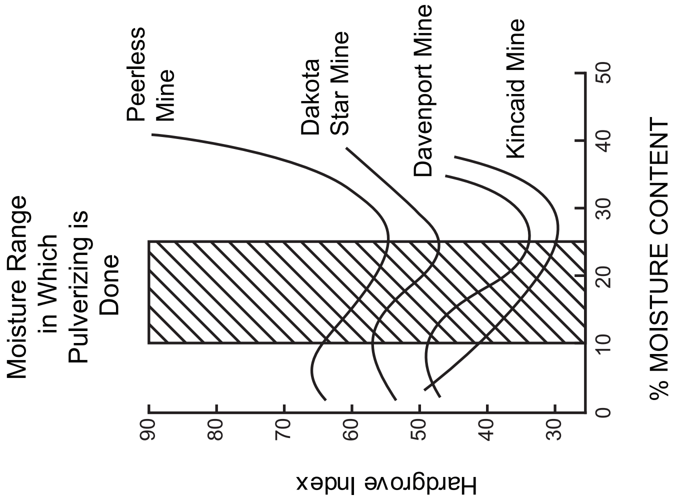


Figure 42-1 – Ball Tube Mill Inspection Guidelines

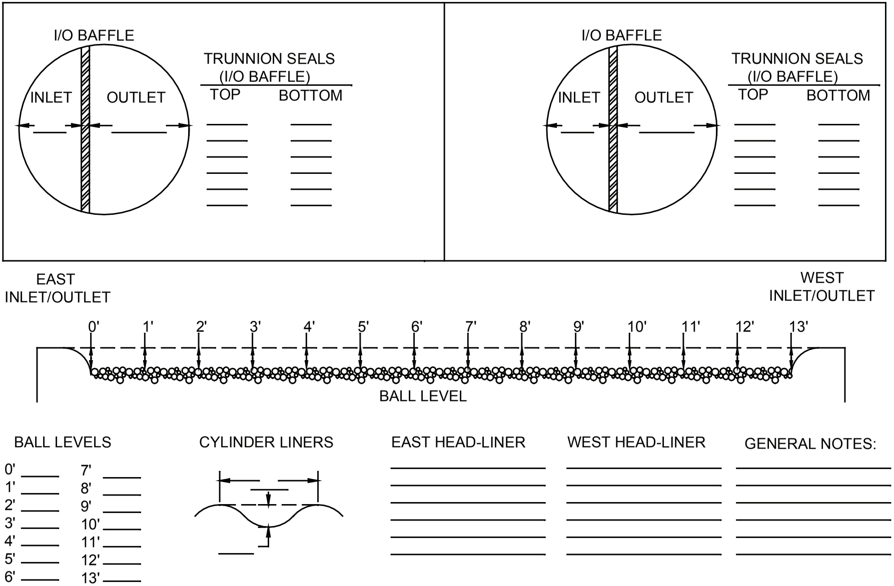
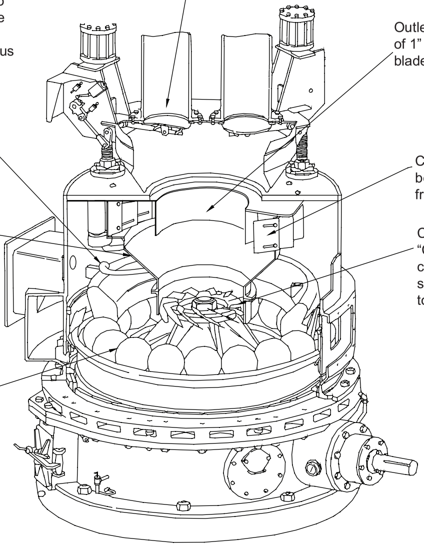


Figure 43-1 – EL Mill Inspection Items

EL Mill Inspection Items



Verify all swing gates open fully

Spring lengths should be of equal length and sufficient pressure to adequatly grind the coal. A table showing recommended spring lengths is included for the various EL pulverizer sizes

Outlet skirt should extend a minimum of 1” past the bottom of the classifier blades

Classifier cone should be “free” of holes/erosion and the interior surface should be “sliding board smooth” to facilitate rejection of coarse particles

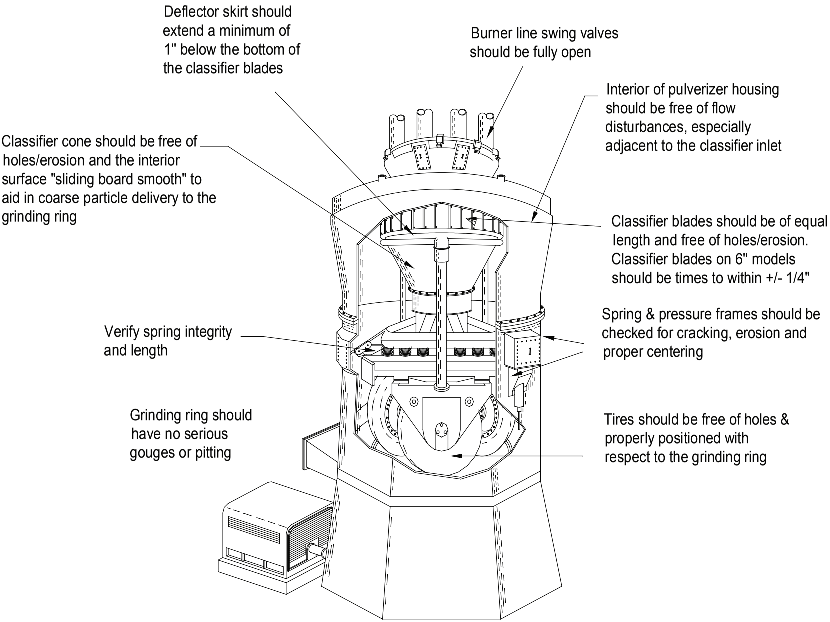
Classifier blades should be of equal length and free of debris and erosion

Clearance between the “Cabbage Cutter” and classifier tailings section should be 1/8” to 1/4”

Balls should be “free” of shape abnormalities and fill balls added when appropriate (average clearance between balls no less than 5/8”)

Figure 44-1 – MPS Mill Inspection Items

MPS Pulverizer Inspection Items



Deflector skirt should extend a minimum of 1" below the bottom of the classifier blades

Burner line swing valves should be fully open

Interior of pulverizer housing should be free of flow disturbances, especially adjacent to the classifier inlet

Classifier cone should be free of holes/erosion and the interior surface "sliding board smooth" to aid in coarse particle delivery to the grinding ring

Classifier blades should be of equal length and free of holes/erosion. Classifier blades on 6" models should be times to within +/- 1/4"

Verify spring integrity and length

Spring & pressure frames should be checked for cracking, erosion and proper centering

Grinding ring should have no serious gouges or pitting

Tires should be free of holes & properly positioned with respect to the grinding ring

Figure 45-1 – Spring Lengths for Ball Pressures
Using Dual Purpose Springs

Pulverizer Size	Compressed Length of Spring in Inches for Pressure per Ball, Pounds										Ball Diameter
	900	1000	1100	1200	1300	1400	1500	1600	1700	1800	Number	
EL-17	4 5/32	4 1/32	3 29/32	-	-	-	-	-	-	-	6	7 1/2
EL-19	3 21/32	3 27/32	3 1/4	-	-	-	-	-	-	-	7	7 1/2
EL-21	4 21/32	4 7/16	4 1/4	-	-	-	-	-	-	-	8	7 1/2
EL-23	5 1/8	5	4 27/32	4 11/16	4 1/2	-	-	-	-	-	6	9 7/8
EL-26	4 3/4	4 23/32	4 17/32	4 3/8	4 13/16	-	-	-	-	-	7	9 7/8
EL-29	5 1/8	5	4 27/32	4 11/36	4 1/2	-	-	-	-	-	8	9 7/8
EL-32	4 29/32	4 3/4	4 9/16	4 13/32	4 1/4	-	-	-	-	-	9	9 7/8
EL-35	-	-	4 21/32	4 4/9	4 3/16	3 31/32	3 3/4	-	-	-	10	9 7/8
EL-38	-	-	4 21/32	4 13/32	4 3/16	3 15/16	3 3/4	-	-	-	10	11 1/4
EL-41	-	-	5 5/8	5 1/2	5 3/8	5 1/4	5 1/8	-	-	-	10	11 1/4
EL-44	-	-	5 1/2	5 11/32	5 7/32	5 1/16	4 15/16	-	-	-	11	11 1/4
EL-47	-	-	6 3/16	5 31/32	5 13/16	5 9/16	5 7/16	5 7/32	5 1/32	4 27/32	11	12 1/4
EL-50	-	-	5 31/32	5 3/4	5 9/16	5 9/16	5 1/8	4 15/16	4 23/32	4 1/2	12	12 1/4
EL-53	-	-	5 3/4	5 17/32	5 5/16	5 11/32	4 27/32	4 5/8	4 3/8	-	13	12 1/4
EL-56	-	-	5 3/4	5 17/32	5 5/16	5 1/16	4 27/32	4 5/8	4 3/8	-	13	12 1/4
EL-64	-	-	6 5/16	6 5/32	6	5 13/16	5 5/8	5 15/32	5 5/16	5 1/8	15	12 1/4
EL-70	-	-	6 3/32	5 7/8	5 11/16	5 1/2	5 5/16	5 1/8	4 29/32	4 23/32	17	12 1/4
EL-76	-	-	5 31/32	5 3/4	5 9/16	5 11/32	5 1/8	4 15/16	4 23/32	4 1/2	18	12 1/4

Recommended Pressure per Ball, Pounds

EL-17 TO 21 = 1100
EL-23 TO 35 = 1300
EL-38 TO 44 = 1500
EL-47 TO 76 = 1700

Figure 46-1 – Typical Volumetric Belt Feeder

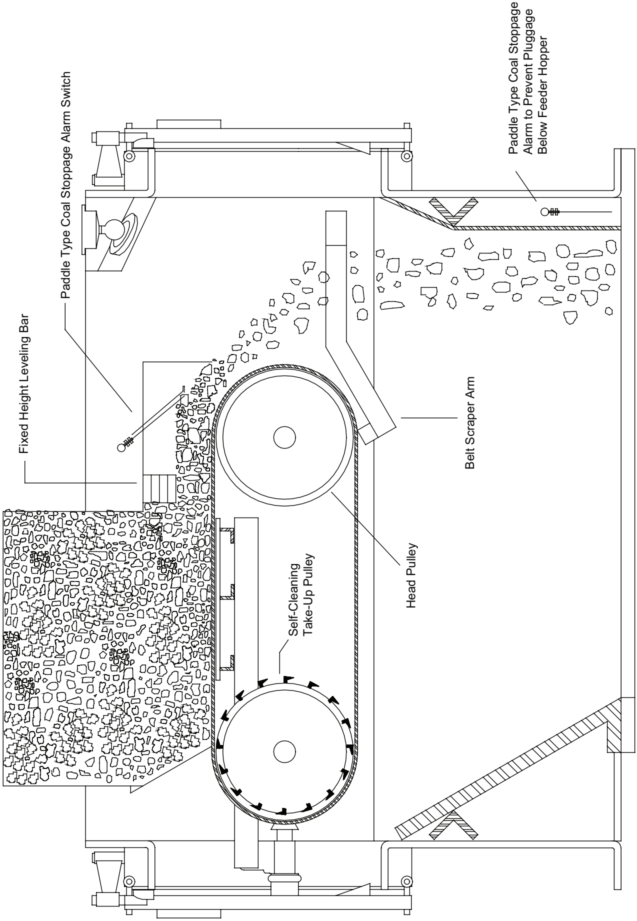
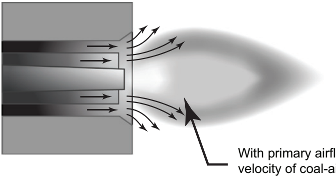


Figure 47-1 – Flame Shape with Optimum Primary Airflow & High Primary Airflow

OPTIMUM PRIMARY AIR FLAME

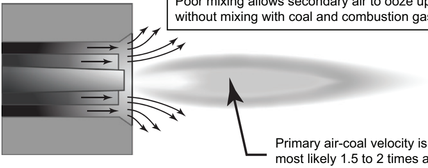


With primary airflow at 1.8:1,
velocity of coal-air mixture 4,000 Fpm

- LOWER VELOCITY ALLOWS SECONDARY AIR TO PENETRATE COAL-AIR MIXTURE.
- BETTER PENETRATION OF SECONDARY AIR MAKES MORE INTENSE FLAME THAT RELEASES HEAT MORE RAPIDLY ALLOWING WATER-WALLS TO ABSORB HEAT AND LOWER FURNACE EXIT GAS TEMPERATURE.
- BETTER PENETRATION OF SECONDARY AIR INTO COAL-AIR MIXTURE ALSO IMPROVES MIXING, PROMOTING A MORE HOMOGENOUS FURNACE EXIT WITH RESPECT TO OXYGEN AND TEMPERATURE.

HIGH PRIMARY AIR FLAME

Poor mixing allows secondary air to ooze up front wall without mixing with coal and combustion gases.



Primary air-coal velocity is 5,500-6,000 Fpm, most likely 1.5 to 2 times as fast as secondary air through the burner

- COAL AIR MIXTURE LEAVING THE BURNER NOZZLE IS TOO FAST FOR SECONDARY AIR TO PENETRATE.
- INABILITY OF SECONDARY AIR TO PENETRATE COAL-PA MIXTURE CAUSES POOR MIXING AT THE BURNERS.
- THIS CAUSES AN ELONGATED, CIGAR SHAPED, SOMETIMES ROLLING FLAME WITH POOR FLAME STABILITY AND SPORATIC IGNITION POINTS THAT ARE OFTEN FAR FROM BURNER NOZZLE.
- POOR MIXING DELAYS COMBUSTION AND HEAT RELEASE CAUSING LESS HEAT TO BE ABSORBED BY THE WATER WALLS. LESS WATER WALL ABSORPTION CAUSES HIGHER EXIT GAS TEMPERATURES. POOR MIXING CAUSES IMBALANCES IN OXYGEN AND TEMPERATURE AT THE FURNACE EXIT.

Figure 48-1 – Conceptual Side View of Twin Nozzle Arrangement

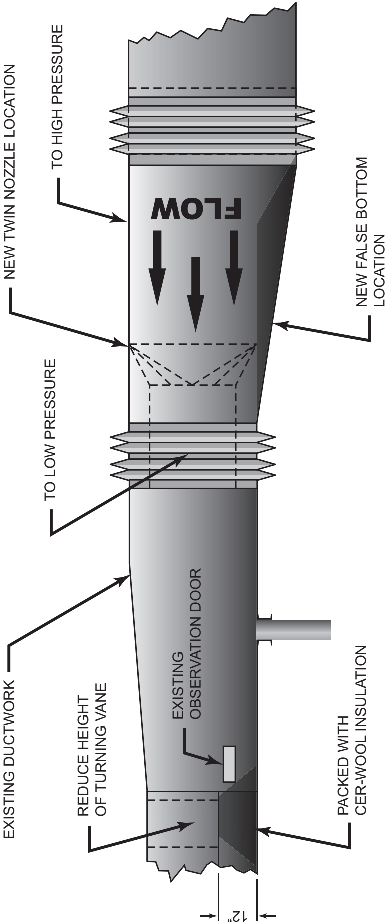


Figure 49-1 - Flow Nozzle Installation to Measure Overfire Airflow

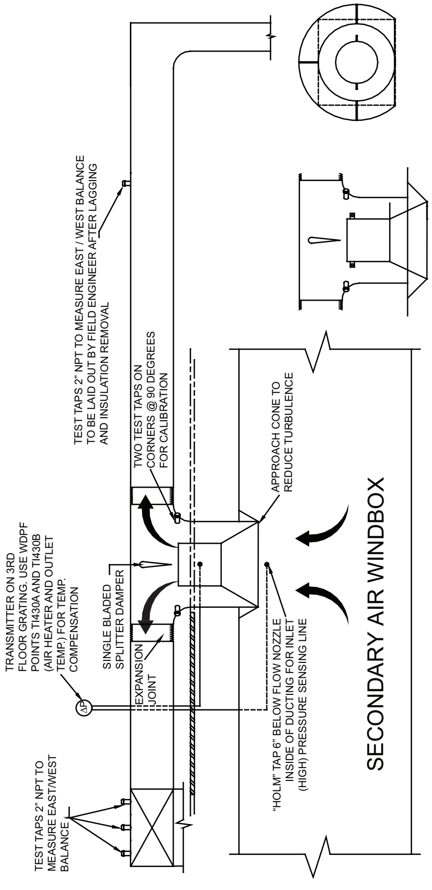


Figure 50-1 – Bowl Mill Troubleshooting

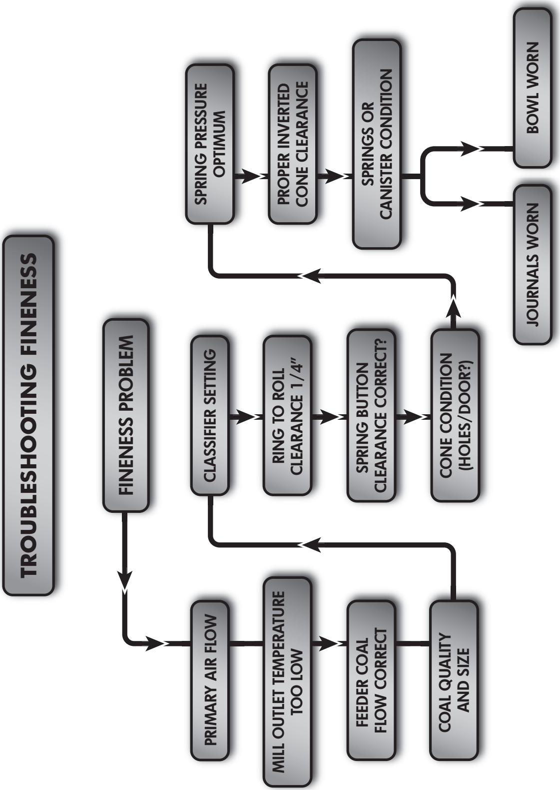


Figure 50-2 – Bowl Mill Troubleshooting

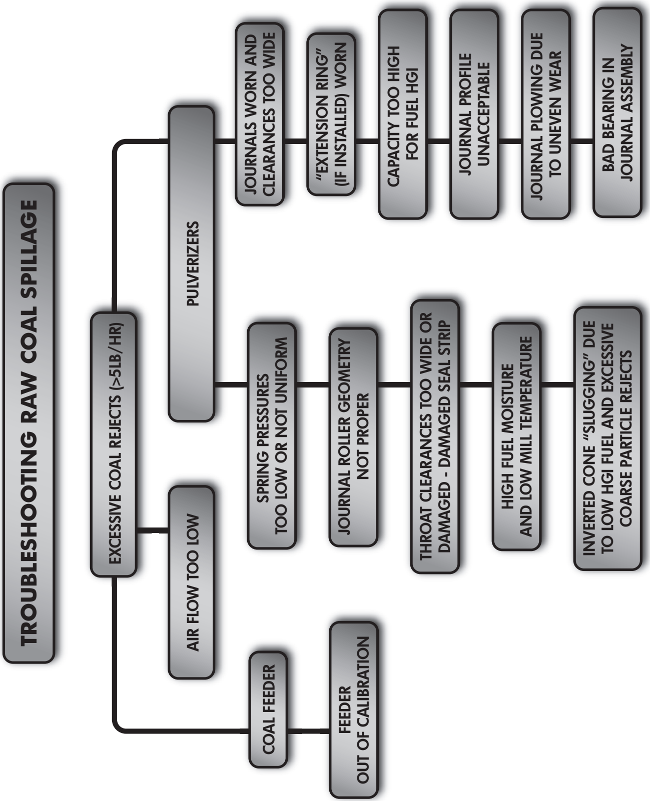


Figure 50-3 – Bowl Mill Troubleshooting

Troubleshooting Low Air Flow

- Fuel Line Coal Plugging
  - Fuel Line/Burner Restrictions
- Inlet to Mills
  - Plugging
  - Layout
  - Damper Stroke
- Classifier
  - Mine Curtain, Rags, etc. Lodged in Classifier Blades
- Control Room Airflow Indication Not Calibrated or Synchronized
  - Leaks in Sensing Lines
  - Transmitter Calibrated; Temperature Compensation Incorrect
  - Control Damper Stroked Properly?

Troubleshooting Pulverizer Fires

- Broken or Wide Clearance of Pulverizer Sweeps
- Stagnant Coal in Mill or in Under-bowl Area
- Excessive Rotating or Fixed Throat Clearances
- Low Primary Air Flow
- Foreign Matter at Mill Inlet or Lodged in Classifiers
  - Rags, rope, etc.

Troubleshooting Rumble Vibration

- Non-optimum Primary Air Vectors in Grinding Zone
- Deflected Air Over Grinding Zone is Interrupted
- Low Primary Air Flow
- Very Fine Coal Rejects and Roll Skidding
- Uneven Spring Pressures
- Worn Grinding Ring
- Worn Tires or Rollers
- Pulverizer Classifier Setting
- Roller Skidding Caused By Mechanical Problems

A Summary of Experiences Related to Achieving Optimum Pulverizer Performance and Fuel Line Balance

Modern utility and industrial burners utilize many independent coal burners to deliver fuel to the furnace for combustion. The number of burners a boiler is equipped with depends on the number of pulverizers and furnace configuration. Typical burner configurations include single wall firing, opposed wall firing and tangential firing. Modern boilers of electric utility size are usually equipped with (6) to (114) separate coal burners. To achieve optimum and efficient combustion of coal, equal quantities of fuel must be delivered to each of the separate burners.

An overwhelming majority of coal fired boilers utilize a pulverized coal firing system. These systems utilize a pulverizer or mill to grind coal to a desired fineness and subsequently transport the coal to the burners using air as a transport medium. Air utilized to transport coal to the burners is considered “Primary Air.” Primary air serves two purposes, these are:

- Transports the pulverized coal from the pulverizer to the burner.
- Provides the necessary heat requirement to facilitate evaporation of surface and inherent moisture in the coal.

After coal and air are mixed at the pulverizer, the resulting mixture of air/coal is typically called dirty airflow. The use of air to transport coal to the burner requires equal airflow through each fuel conduit supplying the burners. Imbalances in airflow through the fuel conduits can affect the quantity of fuel delivered to each burner.

Burners from each pulverizer are usually grouped or paired for combustion stability in the furnace. The majority of pulverizers have three (3) to eight (8) fuel conduits per pulverizer. Usually burners of given elevation or group originate from a single pulverizer. This enables “biasing” of total fuel to a given elevation to control steam temperatures and furnace combustion characteristics. Each pulverizer is an independent system that delivers fuel to the burners originating from the given pulverizer. For this reason, the balance of fuel and air is typically addressed on an individual pulverizer basis. That is, fuel and air are balanced between all burner lines leaving a specific pulverizer.

This will result in uniform air to fuel ratios for all burners, which is critical for combustion performance and control of emissions.

Tolerances for fuel and air balance, which have been accepted as industry standards, are as follows:

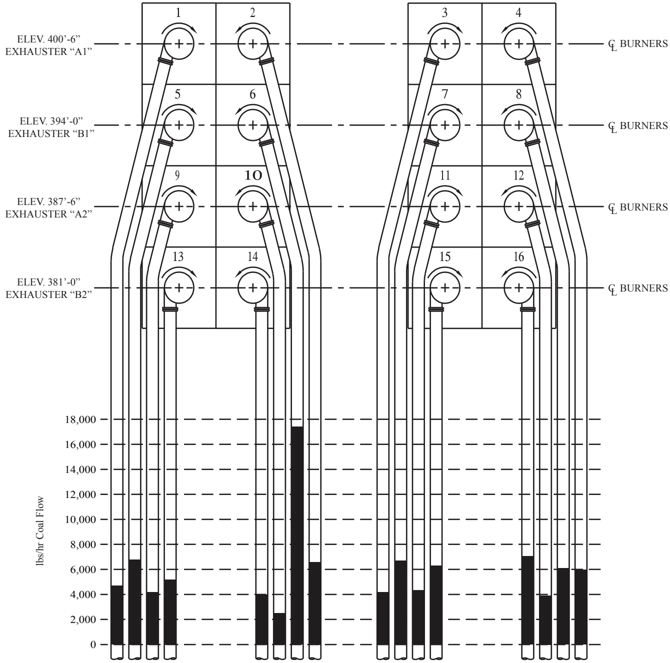
- ±5% balance in dirty airflow between each pulverizer's separate fuel lines.
- ±10% balance in fuel between each pulverizer's separate fuel lines.

Maintaining optimum fuel and air balance is critical to the following items:

- Obtaining acceptable levels on unburned carbon in flyash.
- Uniform release and absorption of heat across the furnace.
- Reduction in furnace slagging and fouling propensities.
- Maintaining furnace and boiler exit gas temperatures within design tolerances.
- Prevention of water-wall wastage and tube metal overheating.

Figure 51-1 illustrates actual test data that indicates gross imbalances in fuel to burners. Poor fuel balance such as this is commonly observed on utility boilers. One of the primary reasons for this is the difficulty in balancing two phase mixtures. Another is gaining the experience and testing equipment to determine fuel balance at plant facilities. In the past, many utility operators have assumed that fuel was balanced or was not critical. The reduced emphasis on fuel and air balancing at the burners was promoted by boiler manufacturers that depended on mixing by the furnace. Since the Clean Air Act Amendment, the importance of air and fuel balance at individual pulverizers and burners has increased.

Figure 51-1 – Test Data Indicating Gross Imbalances in Fuel to Burners



Numerous controllable variables affect the distribution of air and fuel between a pulverizer's separate fuel lines. These variables are as follows:

- Size of pulverizer coal particles leaving the pulverizer (fineness).
- System resistance of each individual fuel conduit.
- Total airflow through the pulverizer that is controlled on a ratio of weight of air to fuel.
- Velocity of air/coal mixture passing through each burner line.
- Maintenance of critical components such as classifiers, classifier cones, riffles, orifices and burner components.

Coal Fineness and Fuel Balance

Coal fineness is ascertained by collecting a representative coal sample from each burner line and shaking the sample through a series of sieves. Coal fineness samples should be collected from all fuel lines of a specific pulverizer. The pulverizer fineness is considered the weighted average of all fineness samples collected. To obtain a representative coal sample, an Isokinetic Sampler must be utilized. The Air/Fuel Sampler and Rotorprobe™ are two types of samplers that have been successfully utilized.

Figure 51-2 – Air/ Fuel Sampling

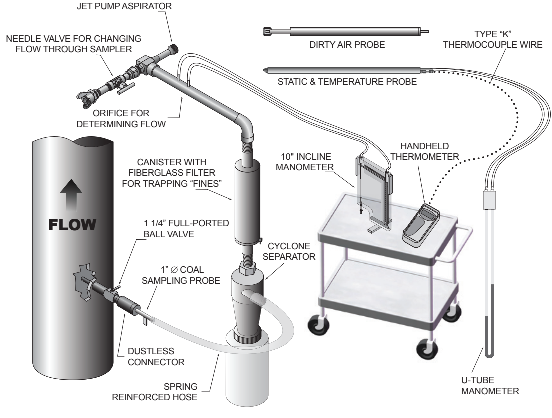
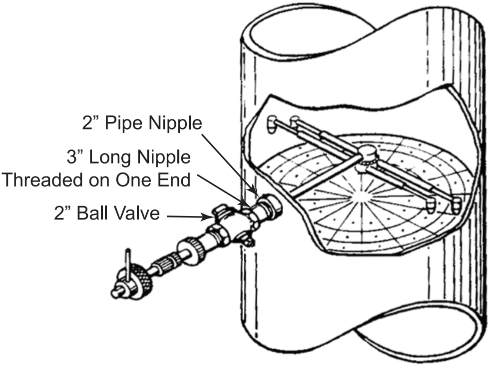
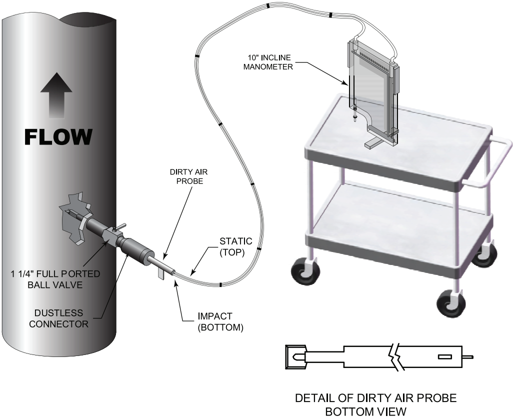


Figure 51-3 – Rotorprobe™ Coal Sampler



The Dirty Air Probe is used in conjunction with the air/fuel sampler and the Rotorprobe™ to measure fuel line airflow and to determine isokinetic sampling rates.

Figure 51-4 – Dirty Air Probe



The quantity of coal passing each sieve is used to determine coal particle sizing. Sieves utilized are ASTM 50, 100, 140 and 200 Mesh.

Figure 51-5 – Arrangement of Coal Sieves for Sieving

PLACE 50 GRAMS OF COAL ON STACKED 50,100,140 AND 200 MESH SIEVES AND SHAKE FOR 20 MINUTES

The numeric designation on ASTM sieves specifies the number of openings in screen or mesh per linear inch. For example, a 200 mesh sieve would have 200 openings per linear inch. Coal fineness levels of 75% passing 200 mesh and 99.7% passing 50 mesh are generally considered acceptable. Boiler manufacturers (OEM) have typically specified coal fineness to be no less than 70% passing 200 mesh with 99% passing 50 mesh.

The OEM fineness specification was determined in the 1960's when boiler furnace designs were very conservative and based on single stage combustion theory. A majority of boilers in operation today are subject to the new Clean Air Act Amendment (CAAA) that limits nitrous oxide (NOx), sulfurous oxide and particulate emissions. 1960's vintage boilers have required modifications to reduce nitrous oxide emissions. NOx emissions are usually reduced by staging combustion to lower the air/fuel stoichiometry in the burner zones where temperatures are sufficient to facilitate formation of nitrous oxides. Reducing air/fuel stoichiometry reduces available air to fully combust carbon in the fuel. Due to this, a higher degree of precision in delivery of fuel and air to the furnace is required. To compensate for imbalances in fuel and air and lower exposure time of fuel carbon to free oxygen at temperatures above ignition points, the OEM coal fineness standard required reevaluation. Low NOx firing configurations require no less than 75% passing 200 mesh with 99.9% passing 50 mesh. Coal fineness is not always required for acceptable NOx emissions, as some burners have performed with compliance NOx levels and poor coal fineness. However, when optimum combustion and flyash of <6% unburned carbon is desired, then improved fineness is required. Fineness levels of 75% passing 200 mesh and 99.7% passing 50 mesh improves fuel distribution as well as unburned carbon in flyash.

After coal fineness is determined by sieving, fineness data should be plotted against the Rosin and Rammler formula to verify the representativeness of the coal sample. A representative sample will plot as a straight line on a Rosin and Rammler chart. A nonlinear plot is indicative of a poor coal sample.

Figure 51-6 – Plot of Coal Fineness on Rosin and Rammler

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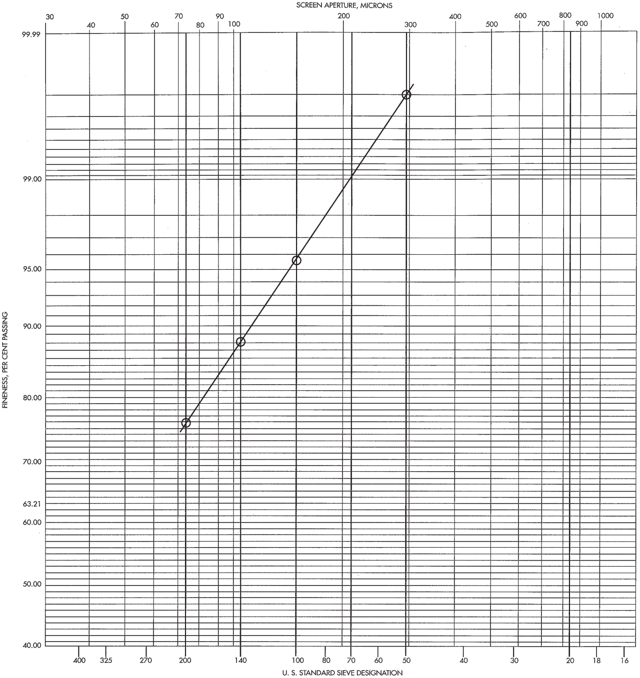
Birmingham, Alabama 35244
Phone: (205) 453-0236 • Fax: (205) 453-0239
www.innovativecombustion.com

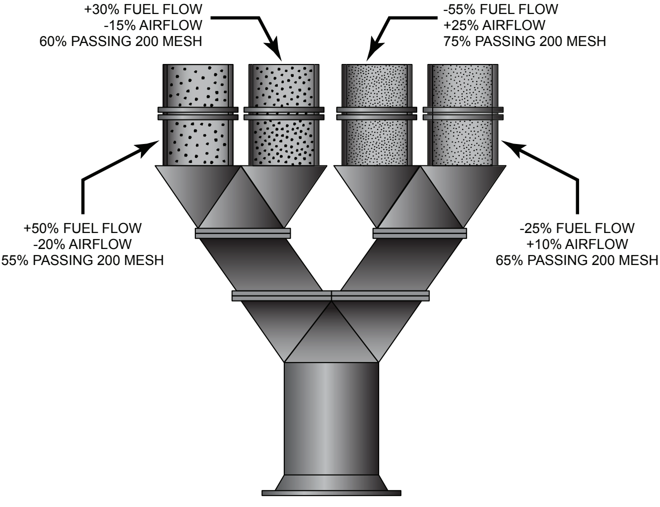


PLOT OF ROSIN AND RAMMLER EQUATION FOR USE WITH PULVERIZED COAL

CLIENT	CONTRACT NO.
SUBJECT	

As fineness increases (reduction in coal particle sizing), fuel balance improves. The finer the coal, the more the two-phase mixture (coal and air) behaves like a fluid rather than a solid in suspension. The more homogenous mixture of air and coal results in more even distribution between the separate burner lines. Pulverizers usually utilize classifiers, which employ the principles of centrifugal separation to reject coarse coal particles back to the pulverizer for regrinding. The "swirl" imparted by centrifugal classification facilitates separation of coarse and fine coal particles. Poor fineness results in a very stratified mixture exiting the classifier due to wide variation in particle sizing. The more massive coal particles (lower fineness) have more momentum when entrained in air at a certain velocity and are more easily stratified than finer coal particles that have less mass, thus lower momentum. After coarse and fine coal particles are separated, fuel and air balance is further aggravated by imbalances in airflow. Typically, burner lines that receive the largest quantity of coarse coal particles have the lowest air velocities.

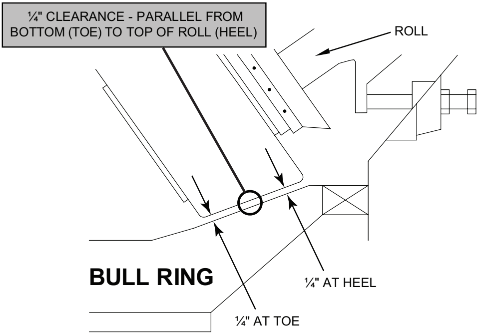
Figure 51-7 – Fuel & Air Balance Relationship



Several mechanical factors effect coal fineness. Some of these factors are the condition and geometry of grinding elements, critical clearances and spring tensions. A short overview of critical tolerances to achieving optimum coal fineness on different types of pulverizers are as follows:

- Pulverizer throat clearances.
- Roll to bowl or tire clearances and roll pressures are critical on Raymond Bowl mills and MPS mills.
- Grinding ring geometry, ball size, number of balls and spring compressions on EL pulverizers.
- Cabbage cutter clearances and classifier cone condition.
- Ball charge, size of balls, inlet/outlet baffle and trunion seal plates on ball tube mills.

Figure 51-8 – Proper Roll to Bowl Clearance on Raymond Bowl Mill Pulverizer



Less than desired mill performance, after all mechanical and maintenance variables are addressed, may be due to marginal pulverizer capacity or coal quality differing from the pulverizer capability or design. Pulverizer modification is sometimes required to achieve desired fineness and fuel balance.

Common Pulverizer Modifications

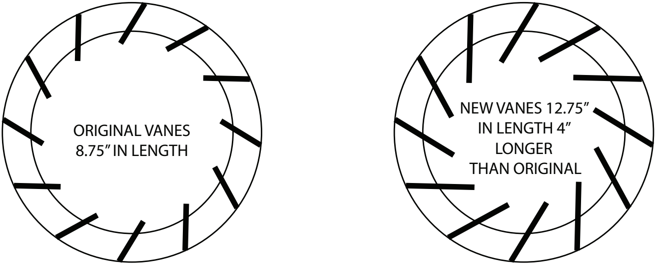
Replacement of curved classifier vanes with straight vanes on Raymond Bowl mills

- Raymond Bowl mills utilize classifier blades that are curved on the trailing edge. This curve arrests the “swirl” imparted by vanes that facilitates separation of coarse and fine coal particles. Straight classifier blades increase “swirl”, improving fineness and homogenization of the two phase mixture.

Extended classifier blades

- Increased blade length increases swirl that rejects more coarse particles and improves fuel distribution. Classifier blade extensions have been completed on all pulverizers utilizing centrifugal type classifiers. Extended classifier blades can improve fineness between 5% and 15% passing 200 mesh. The figure below illustrates typical classifier blade extensions for an EL pulverizer and improvement in fuel distribution.

Figure 51-9 – Improvement in Pulverizer Fuel Balance with Extended Classifier Blades



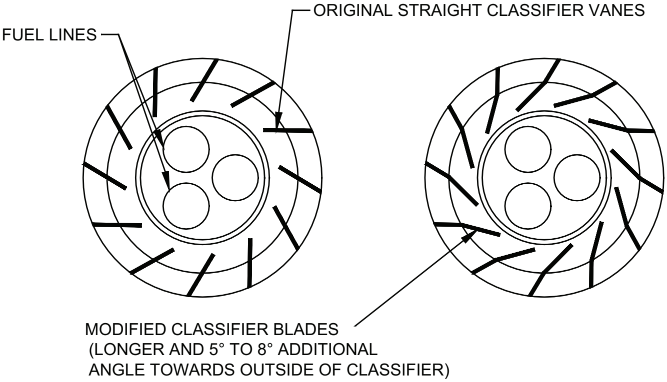
PRE-MODIFICATION TESTING			POST-MODIFICATION TESTING	
DIRTY AIR VELOCITIES	RECOVERED SAMPLE (g)		DIRTY AIR VELOCITIES	FUEL FLOW SAMPLE (g)
+8.27%	+13.2%	MAXIMUM DEVIATION	+1.55%	+5.45%
-6.07%	-18.3%	MINIMUM DEVIATION	-2.33%	-6.05%

DEVIATIONS ARE % DEVIATION FROM MEAN FUEL FLOW OR RECOVERY WEIGHT

Installation of angled classifier blades that change the diameter of the swirl

- Blades are angled further towards the outside of the mill and the back of other classifier blades. Larger coal particles, which are accelerated more than fines due to higher momentum, collide with classifier blades and are rejected. Angled classifier blades are intended for pulverizers with fixed classifier blades such as the EL and MPS pulverizers. Classifier blades on Raymond Bowl mills are on a rotating axle that allows varying angles.

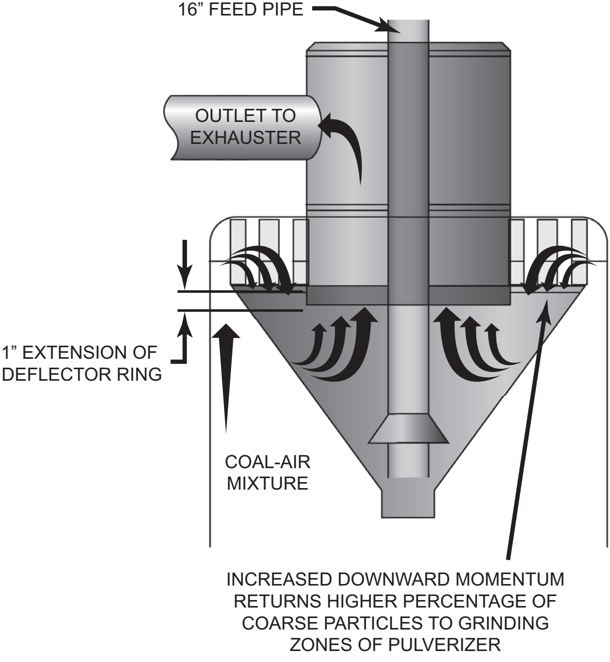
Figure 51-10 – Angled Classifier Blades for MPS or EL Type Pulverizers



Extension of classifier outlet skirts or deflector rings

- This is performed to change the direction of the coal particles in a downward direction towards the classifier reject area. The increased downward momentum and 180° turn of the particles with higher mass allows less of these large particles to be carried to the fuel lines. This modification is applicable to all pulverizers utilizing centrifugal classifiers. A 1” extension of the outlet skirt below the bottom of the classifier blades (Bowl mills, also called deflector ring) or the inverted top hat (EL pulverizers) is usually sufficient.

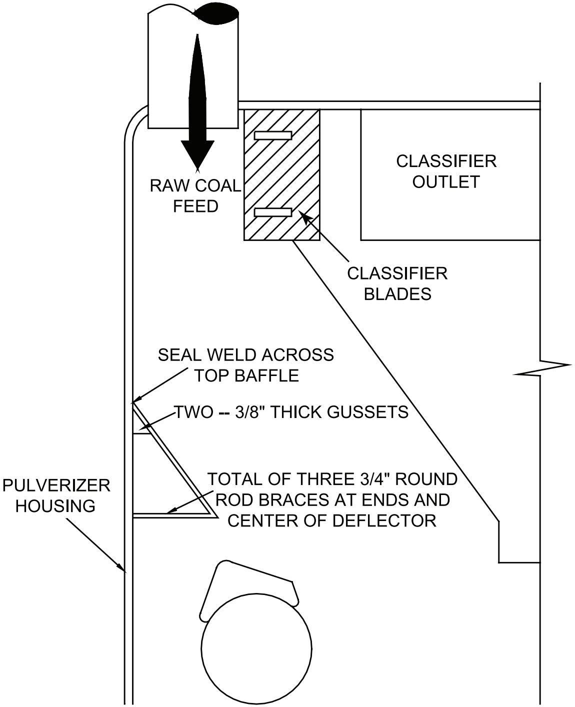
Figure 51-11 – Classifier Outlet Skirt Extension



Installation of raw coal deflectors on EL pulverizers

- If raw coal deflectors are not installed on EL pulverizers, raw coal is dumped on the outside of the grinding ring. Coal must pass from the inside of the grinding rings to the outside by passing through balls for efficient pulverization. The raw coal deflector insures this. The figure below illustrates a typical raw coal deflector installed in an EL Pulverizer.

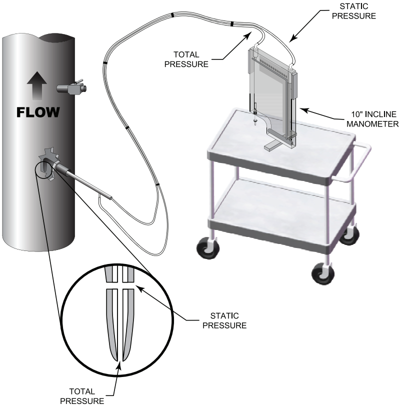
Figure 51-12 – Raw Coal Deflector for EL Pulverizers



Clean Air Balancing

Balancing system resistance of fuel lines on clean air is the first step of an empirically derived approach to balancing pulverizer fuel and air. Clean air balance is defined as balance of airflow between a pulverizer's fuel lines in the absence of fuel. This is achieved by forcing air through the pulverizer at normal operating mill outlet temperatures with primary air fans or exhausters while the feeder remains off-line. Clean air balance is determined by measuring the velocity of air flowing through each individual fuel line with a standard Pitot tube.

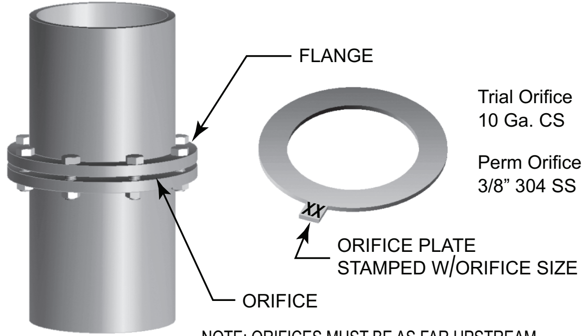
Figure 51-13 – Standard Pitot Tube and Incline Manometer



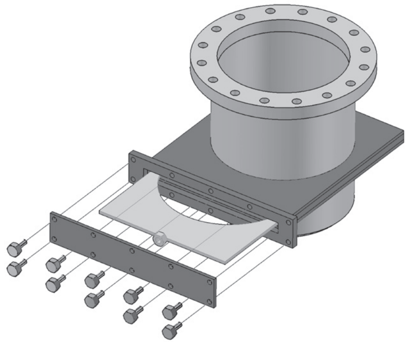
In most cases, primary airflow is higher than desired and will be reduced to optimize performance. Prior to optimization of primary airflow, it is prudent to perform clean air balancing. This will ensure minimum fuel line velocities are maintained after optimization of primary airflow. Air velocity in all fuel lines must exceed 3,300 feet/minute (Fpm) to insure coal entrainment in primary air. Air velocities below 3,000 Fpm allow coal to fall out and accumulate or "dune" in horizontal runs of fuel lines. The 3,300 Fpm minimum velocity includes a 10% safety margin above the absolute minimum line velocity of 3,000 Fpm. Coal line accumulations may cause burner pulsations, flame instabilities and possible stoppages. Fuel lines are balanced by an iterative process utilizing 10 gauge carbon steel trial orifices. Clean air balance with a maximum of ±2% deviation from the mean between all fuel lines on a pulverizer must be achieved. After optimum orifice configuration is determined, permanent hardened 400 Series stainless orifices are installed.

Computer modeling is sometimes performed to determine orifice sizing. Following installation of orifices, clean air balance should always be verified by Pitot traverse of fuel lines. Clean air tests by Pitot traverse is also required to ascertain if any fuel line resistances, not shown by drawings, are present.

Figure 51-14 – Typical Coal Line Orifices



NOTE: ORIFICES MUST BE AS FAR UPSTREAM OR DOWNSTREAM OF TEST TAPS AS POSSIBLE. >10 PIPE DIAMETERS PREFERRED



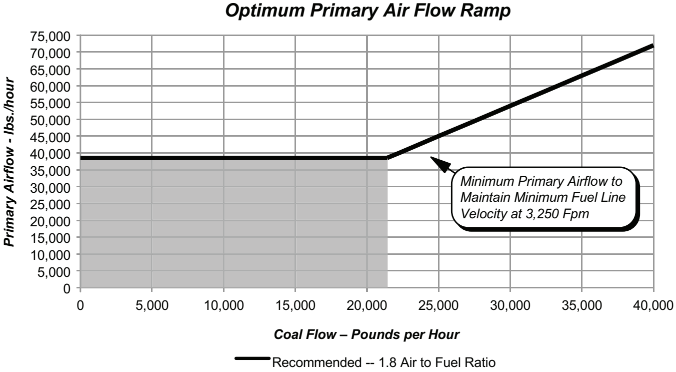
Pulverizer Airflow

High primary airflow can cause poor coal fineness as well as poor fuel balance. Optimum primary airflow depends on the type of pulverizer. Primary airflow should be ramped at an appropriate air to fuel ratio. Optimum pulverizer airflow in most cases is as follows:

Pulverizer Type	*Lbs. Air per Lb. Coal*
MPS and EL Mills	1.5 to 1.8
Raymond Bowl Mills	1.5 to 2.0
Ball Tube Mills	1.1 to 1.3
Attrita Mills	1.2 to 1.6

The graph below illustrates a typical air to fuel relationship for a MPS, EL or Raymond Bowl pulverizer. To characterize primary airflow, accurate control and measurement of primary air and fuel must be facilitated. Load cell gravimetric feeders are the preferred method of fuel flow control.

Figure 51-15 – Typical Primary Airflow Ramp



Flow Nozzles or Venturis usually provide the most accurate and reliable means to measure and control primary airflow. The figures below illustrate the Venturi and Flow Nozzle that are frequently recommended by ICT.

Figure 51-16 – Mix Venturi on a Raymond Bowl Mill

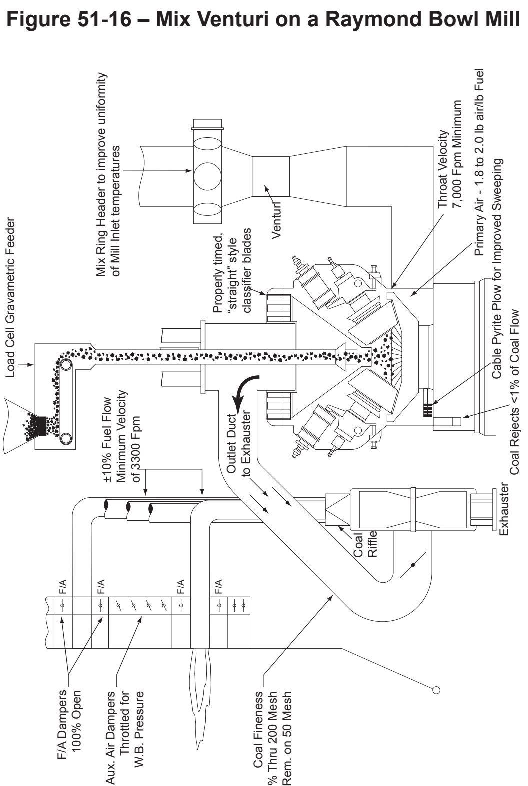
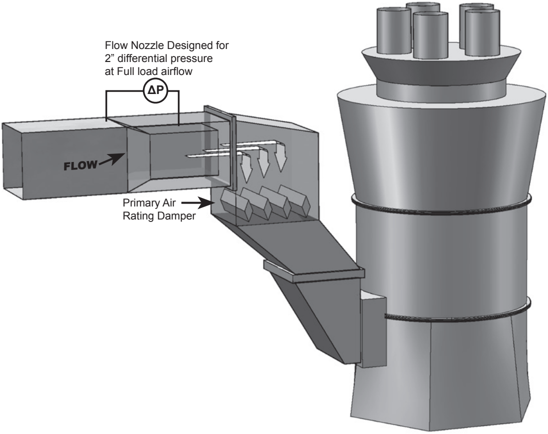
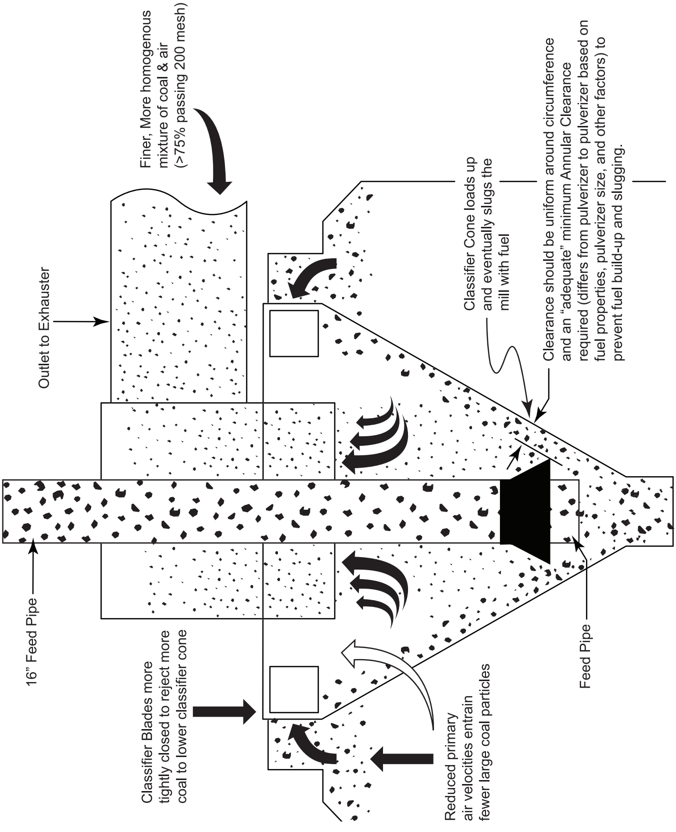


Figure 51-17 – Flow Nozzle on a MPS-89 Pulverizer



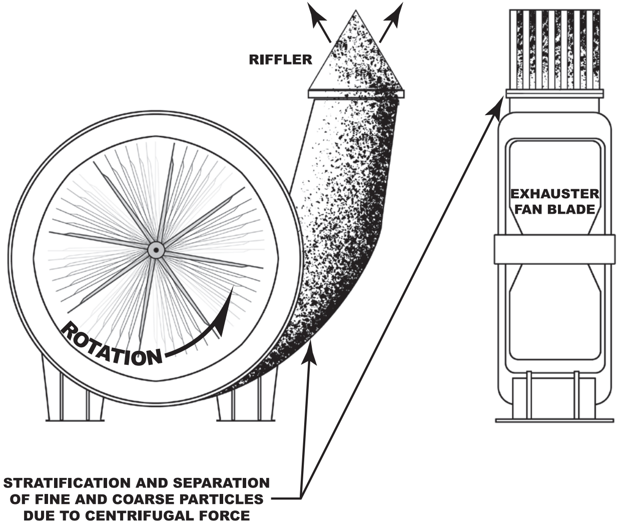
High primary airflow contributes to poor coal fineness by increasing air velocities in the classifier and reducing overall retention time of coal in the grinding zones. Increases in primary airflow correlate to an increase in velocities at the classifier outlet of the pulverizer. Higher velocity air at the classifier outlet has sufficient energy to entrap larger more massive coal particles. Lower velocities allow larger particles to be returned to the grinding zones. Inverted cone clearances, if so equipped, must be correct before optimizing primary airflow. Non-optimum inverted cone clearance can result in pulverizer swings that can cause high motor current trips and poor 50 mesh fineness.

Figure 51-18 – Entrapment of Large Coal Particles by High P.A. Flow and Inverted Cone Clearance



High primary airflow causes poor fuel balance by increasing separation of coarse and fine coal particles. Higher velocities result in higher kinetic energy or momentum of coal particles increasing stratification when centrifugal forces or direction changes are imparted on coal particles.

Figure 51-19 – Increased Stratification and Reduced Coal Riffle Effectiveness Caused by High Primary Airflow



Note: Riffles, when installed above an exhauster, should be mounted 90° to the exhauster shaft for uniform splitting of coal particles.

Additional adverse effects of high primary airflow on unit performance are as follows:

- Poor flame stability at lower loads and flame ignition points unattached to burner nozzles

  Optimized primary airflow (1.8 pounds air per pound of fuel) will maintain velocities at the coal nozzle tip within the best range of flame propagation speed for flame stability and improved combustion efficiency.

- Increased air heater exit gas temperatures

  Higher dry gas losses are the result of increased tempering air usage. Higher air to fuel ratios require lower temperature at the pulverizer inlet to maintain pulverizer outlet temperature, decreasing the quantity of hot air from the air pre-heaters. Additional dry gas losses are incurred by heat loss to heat additional ambient (tempering) air after injection into the boiler "boundary."

- Increased furnace exit gas temperatures

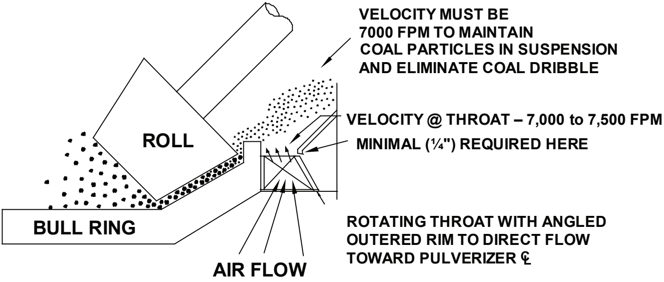
  High primary airflow increases the differential in velocity between the primary air/fuel mixture and the secondary (combustion) air. This stages or delays combustion that allows a large percentage of heat to be released above the burner belt zone. Lower heat release in the burner belt zone results in less heat absorption by the waterwalls and the subsequent elevation of the furnace exit gas temperature.

- Higher proclivity towards mill fires or explosions
- Higher slagging or fouling propensity
- Increased wear of coal lines, burner nozzles and exhauster components
- Slight increase in auxiliary power due to the increased horsepower demand of the exhauster required to convey additional primary airflow
- Increased nitrous oxide emissions

  Increased nitrous oxide emissions is facilitated by injecting more of the total air, for a given excess air, as primary air in the high temperature root of the burner flame rather than secondary air.

Pulverizer throat clearances must be verified prior to optimization of primary airflow. Pulverizer throats that are not properly sized or have been enlarged by wear may result in serious coal dribble or spillage. Coal dribble is raw coal that is rejected through the pulverizer's pyrite discharge. This is caused when the velocity across the pulverizer throat is too low to maintain suspension of coal. Air velocities through the pulverizer throat should be between 6,500 and 7,500 Fpm when calculated on a free jet basis. Air at velocities above 7,000 Fpm will have sufficient energy to prevent coal from falling through the throat and will carry coal to the classifier.

Figure 51-20 – Proper Pulverizer Throat Velocities



Pulverizer Outlet Temperature

Maintaining optimum mill outlet temperature is required to insure fuel moisture is evaporated and for proper ignition of coal at the burners. Pulverizer outlet temperature should be no less than 155°F on MPS, EL and ball tube pulverizers. Attrita pulverizers should be maintained at 200°F to 225°F. Temperatures less than 155°F will not promote complete evaporation of fuel moisture. Low pulverizer outlet temperature can lead to coal accumulations on fuel line pipe walls, poor combustion and poor fineness. The ability of a pulverizer to grind coal to fines is debilitated by fuel moisture. Pulverizer outlet temperature on Raymond Bowl pulverizers is often measured at the exhauster outlet.

If pulverizer outlet temperature is measured at this point, mill outlet temperature should be maintained at 180°F. Temperatures at the exhauster outlet are usually 15° to 30°F higher than at the classifier outlet. This temperature differential is caused by the additional heat introduced by the dynamic inefficiency of the radial bladed exhauster fan, which has typical efficiencies of 40% to 50%. Maintaining low pulverizer outlet temperature is also a heat rate penalty. While lower pulverizer outlet temperatures are maintained, a higher percentage of total primary airflow is tempering airflow rather than hot air. Tempering air is at ambient temperature and is introduced through atmospheric damper or ducting from the forced draft fans. Tempering air, which has not been heated by the air heater, is injected into the boiler boundary resulting in higher dry gas losses. This also facilitates less air passing across the air heater, which in turn results in a slight increase in air heater exit gas temperature.

Summary

Achieving optimum pulverizer performance is of paramount importance to heat rate, boiler reliability, emissions compliance and flyash combustibles. To summarize, the following items are required to achieve optimized pulverizer performance:

- Pipe to pipe clean air balance within ±2% of the mean pipe velocity
- Pipe to pipe fuel balance within ±10% of the pulverizer’s mean pipe fuel flow
- Pipe to pipe dirty air velocity balance within ±5% of the pulverizer’s mean pipe dirty air velocity
- Air to fuel ratio of 1.8 pounds of air per pound of fuel on MPS, EL and Raymond Bowl pulverizers
- Minimum coal fineness level of 75% passing 200 mesh and less than 0.3% remaining on 50 mesh
- Pulverizer to pulverizer mass air and fuel balance within ±5%
- Pulverizer outlet temperature of 155°F or higher
- Minimum fuel line velocity of 3,300 Fpm
- Pulverizer throat velocity of 6,500 to 7,500 Fpm calculated on a free jet basis
- Optimum mechanical tolerances. (i.e. spring pressures, grinding element condition, ball sizes, etc.)

Ash Fusion Temperatures

Figure 52-1 – Ash Fusion Temperatures by ASTM D-1875

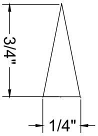
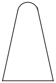
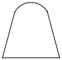
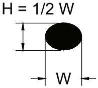
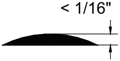
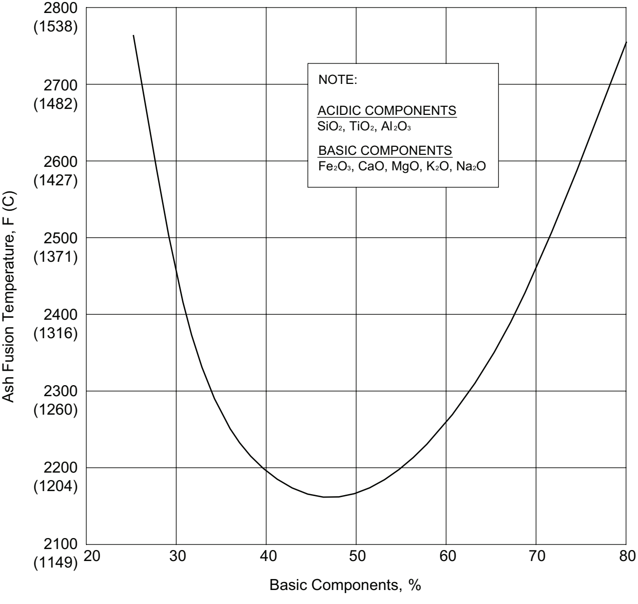
DRY ASH CONE 1/4" X 3/4"	INITIAL DEFORMATION	SOFTENING TEMPERATURE	HEMISPHERICAL TEMPERATURE	FLUID TEMPERATURE
				
ASH IS A DRY POWDER AND WILL BE FLYASH AT THIS OR LOWER TEMPERATURES	TOP OF CONE BEGINS TO DEFORM, ASH IN TRANSIT THROUGH FURNACE HAS A SLIGHT TENDENCY TO STICK TOGETHER OR SLOWLY BUILD UP ON TUBE SURFACES	OFTEN CALLED "FUSION TEMPERATURE" ASH CONE HAS DEFORMED TO SPHERICAL SHAPE TYPICALLY STICKS TO TUBES THAT ARE ≤1000°F WHEN ASH IS QUENCHED	FURTHER DEFORMATION TO HEMISPHERICAL SHAPE; ACCELERATED TENDENCY TO MASS TOGETHER AND STICK IN LARGE QUANTITIES TO TUBE SURFACES	MELTED TO LIQUID THAT WILL FLOW IN STREAMS OR DRIP, WHEN QUENCHED, MOLTEN ASH TURNS SOLID INTO HARD & DENSE CLINKER ***HEAVY SLAGGING ASSURED AT THIS TEMPERATURE***

Figure 52-2 – Fusion Temperatures versus Basic/ Acidic Constituents Typical for Eastern Bituminous Coal



NOTE:

ACIDIC COMPONENTS
SiO_2, TiO_2, Al_2O_3

BASIC COMPONENTS
Fe_2O_3, CaO, MgO, K_2O, Na_2O

Advanced Coal Quality and Combustion

by Rod Hatt

Review of Basic Coal Quality

It is important to understand the results and meaning of the following coal tests.

Proximate

- Originally
  - Moisture
  - Ash
  - Volatile
  - Fixed Carbon

- Short Prox
  - Sulfur
  - Heating value (HHV, LHV)

- Uses
  - Rank determination - Reactivity
  - Ash loading
  - SO_2
  - Air Dry moisture

Ultimate

- Carbon
- Hydrogen
- Nitrogen
- Oxygen

Forms of Sulfur

Look for Pyrite, Sulfate = oxidized

Ash Fusion Temperatures

- This is a physical test with variable atmospheric conditions.
- Best used as an indication of what combustion conditions do to slag viscosity
- High variability lab to lab

Major and Minor Ash Chemistry

- More consistent lab to lab?
- Try to infer slag viscosity and fouling potential.
- Elemental loading
- ESP Performance

Hardgrove Grindability Index

- Variable with low and mid-ranked coals due to moisture influences

Equilibrium moisture

Coals are dustier if they fall below the equilibrium moisture level, even if it is just the surface of large pieces

Combustion Tune-up Procedures

- Air Flow and Balancing
  - Oxygen (O_2) Readings
    - Short history of Bailey Combustion Controls
    - In situ Probes
  - Verifying O_2 Readings
    - How much leakage
    - Induced draft fans
  - Comparing O_2 to air flow measurements

    Excess air = $20.9/(20.9-O_2)$

    - Look up design air flows
    - Calculate air flow and compare to measured flow
  - Air Heater Leakage

    $= 90 \times ((O_2 \text{ leaving} - O_2 \text{ Entering}) / (21 - O_2 \text{ Leaving})$

    or perform both excess air and take difference
  - Other Leakage
    - Is the leakage before the ESP
  - Balancing
    - O_2 levels
    - Temperature
    - Flows
    - Opacity
    - NOx

Pulverizer Performance

- Coal Sizing
  - Hard work
  - Sampling is critical
    - ASTM, ASME, Storm
  - Screening, - worn screens, QCQA
  - Rosin-Rammler

  - 200 mesh for capacity
  - 50 mesh for LOI

- Air and Fuel Flow
  - Plugged pipes
  - Plugged riffles

- Clean and Dirty Coal Pipe Measurements
  - Error in measurements
  - Both important
  - Combine with iso-kinetic sampling for mass balance

- Pyrite Rejects
  - These are a sample of the rocks and minerals in a coal
    - Consider tuning this aspect of mill for coal cleaning

- Primary Air Flow
  - Moves coal though pipes
  - Minimum velocities to avoid settling out of dust
  - Temperature control
  - Impacts flame front

- Look for coal settling out on air inlet ducts

- Adjustments include:
  - Roller and journal pressure, alignment, air flow, classifiers, temperature, ball charge, ball size

LOI Testing and Combustion Verification

- LOI Test
  - Loss on Ignition
  - Includes drying step

- Carbon in Ash
  - More expensive

- HHV of Ash

- Done by standard additive method

- Sampling Location
  - ESP Hoppers
  - Dust silo
  - Ductwork

- Sampling Methods
  - Bucket
  - Pipe
  - Corn thief
  - Street elbow
  - Iso-kinetic
  - Grid-work of points
  - EPA Method 17
  - EPA Method 5

- Operator Feedback
  - Don’t wait for test results if it is black
  - Calibrated jars
  - Take data and discuss operations with operator while sample is being collected

- CO Analyses
  - Use with O_2 and NOx

- NOx Analyses

<u>Results Engineering</u>

- Boiler Efficiency Testing
  - Output/Input
    - Eff. = Heat in Steam/Btus of Coal

  - Heat Loss Method
    - Start With 100% and then remove
      - Moisture in air
      - Moisture in fuel
      - Moisture from hydrogen
      - Unburnt carbon
      - Heat in flue gas
      - Radiation
      - Unknown and fudge

- Problem areas
  - Hard work
  - Need coal and ash samples
  - Use theory rather than measure

- Improving Boiler Efficiency

- Improving Combustion
  - Low LOI
  - Low excess air

- Optimizing Combustion
  - O_2 verse Boiler Efficiency

- Optimizing NOx
  - May require higher CO and or higher LOI
  - Small sizing critical

- Unit Heat Rate
  - Input/Output

Heat rate = Btus input / kilowatts output

- Coal Sampling and Testing Results are Critical
  - Concerns and Opportunities
    - Don't let the sample dry out
  - Gross and net differ due to the auxiliary power that the plant uses itself

- Performance Diagrams
  - Feed water heaters and turbine cycle
  - ONE SHOT ITERATION

<u>Ash Deposits</u> – Slagging verse Fouling

- Slag is Molten, Fouling is Sulfate Salts

TABLE I - Major Causes of Ash Deposits

Fuel Related	Large pyrite particles that impact the furnace wall before they completely combust
	Clay minerals that contain significant amounts of iron, calcium, sodium or potassium causing them to have low melting temperatures
	Interaction of pyrite, clays and alkalis with alumino silicates to form low viscosity melts
	Extremely fine or organically bound alkalis
Equipment Related	Soot blowers not in operation or used improperly
	Poor pulverization of fuel
	Improper air to fuel ratio
	Burners damaged or improperly adjusted
	Changes in operation of boiler or other equipment
Design Related	Furnace size too small for fuel
	Tube material and/or spacing inadequate
	Soot blowing coverage inadequate
	No means provided to observe slag buildup
	Most slag begins on the furnace walls and then proceeds up the furnace

Basic Analytical Procedures

Ash Fusion Temperatures

- Spread between ID and FT
- Spread between Oxidizing and Reducing
- Spread between laboratories
- Impact of combustion
- Cross plotting between other coal characteristics

Major and Minor Ash Elements

ASTM designates the reporting of ash elements in their fully oxidized form. This is due to the assumption that the elements are found in the ash, and ash is produced in an oxidizing atmosphere at high temperature. These elements may or may not be in the fully oxidized form in actual power plant ash, and certainly not all in the oxidized form in the original coal. The challenge in interpreting ash analyses is to understand the actual minerals in the coal and the mineral transformations. An additional complication is that some elements can be bound to the actual coal material and are not in a mineral form. This is particularly true for calcium and sodium in low rank coals. The high oxygen content of these coals provides places for these elements to stick to the coal due to ground water movement.

One other element that causes confusion in ASTM analyses is sulfur. It is reported as SO_3 – sulfur trioxide – which is a gas commonly found in flue gas. The SO_3 reported in ASTM analyses is truly sulfur in the sulfite or sulfate form. A reaction takes place during the ashing of the coal between the calcium and the sulfur gases forming calcium sulfate. This reaction takes place at temperatures in the 1500° – 1800°F range. The same reaction is used in fluidized bed combustors to capture sulfur using limestone. The laboratory ashing furnace has a temperature of 1300° - 1400°F and of course the burning coal raises this locally. The SO_3 reported in coal ash analyses is usually much higher than that found in the fly and bottom ash, due to their formation at much higher temperatures where the calcium and sulfur gases cannot react. The main fouling reaction is this same reaction and will be discussed in detail in a following section.

Acid Oxides or Glass Formers

SiO_2 – Silicon dioxide - Silica – Represents elemental silicon found in the mineral Quartz, and the aluminosilicate rocks Shale, Slate, and Clays

Al_2O_3 – Aluminum oxide - Alumina – Represents the aluminum found in the aluminosilicate rocks and minerals, not the mineral compound (Al_2O_3) which is an industrial abrasive, and also gems, rubies and sapphires

TiO_2 – Titanium dioxide – Titania – Seems to always be about one to two percent

Basic Oxides or Fluxing agents or Gluing Elements
Fe_2O_3 – Iron oxide – hematite – Represents the elemental iron in its fully oxidized form. Iron in coal is in pyritic and carbonate forms, iron in ash can be in elemental, reduced and oxidized form. This element is one of the most important in influencing slagging behavior.

CaO – Calcium oxide – lime – represents both mineral (calcite, limestone) and organically bound calcium. The oxidation state of this element is basically fixed to CaO. There is less impact of the oxidizing conditions on the fusion temperatures of high calcium coal ash. This element is also one of the most important in slag and fouling deposits.

MgO – Magnesium oxide – generally lower, (less than six percent) than the calcium, but follows calcium levels as the mineral dolomite.

K_2O – Potassium oxide – typically found in clays and other aluminosilicates.

Na_2O – Sodium oxide – found in several forms depending on coal rank and depositional environment. It is an organically-bound form common in low rank coals and NaCl found in coals saturated with sea or briny water. Sodium is also one of the three important elements in slag and fouling deposits.

SO_3 – Sulfur trioxide – actually in the solid form of sulfates combined with calcium and other basic elements. Not commonly found in high levels in fly and bottom ash. It is found in fouling deposits held together by calcium sulfate.

Basic Slagging factors

B/A – Base to acid ratio, sum of total bases divided by sum of all acid elements

$$B/A = \frac{Fe_2O_3 + CaO + MgO + K_2O + Na_2O}{SiO_2 + Al_2O_3 + TiO_2}$$

Since most of the basic elements are troublesome, the B/A is an indication of the level of fluxing agents

Slagging Factor – Dry sulfur times the B/A provides a result that is similar to an iron squared term $(Fe_2O_3)^2$, this is due to Fe_2O_3 being a base and a significant portion of the sulfur being in the pyritic form, FeS_2.

Ash and Elemental Loading – ash and important elements reported in pounds per million Btus. We already use $/MBtu to evaluate the price of coal and report sulfur dioxide SO_2 levels in Lbs./MBtu. These calculations are reported ash and elemental analyses.

Lb. Ash/MBtu = %Ash/(Btu/lb./10,000)

Elemental loading = Ash Load x Element %/100

Example – Which coal has more iron?

	Coal 1	Coal 2
Ash	=9.0%	14.0%
Btu/lb	=12,300	11,200
Fe_2O_3	=12.0%	9.0%

Coal 1

Lb. Ash/MBtu = 9/(12,300/10,000) = 9/1.23 = 7.3

Lbs Fe_2O_3 = 7.3 x 12.0/100 = 7.3 x 0.12 = 0.88

Coal 2

Lb. Ash/MBtu = 14/(11,200/10,000) = 14/1.12 = 12.5

Lbs Fe_2O_3 = 12.5 x 9.0/100 = 7.3 x 0.09 = 1.13

Percent iron that Coal 2 has more than Coal 1 = 1.13/.88 = 28 % more iron in Coal 2

This example illustrates the importance of data manipulation rather than just using the straight ASTM levels reported by the laboratories.

Advanced Methods for Slag

- Mineral and Elemental Analyses of Coal
  - Computer Controlled Scanning Electron Microscopy (CCSEM)
    - Uses Energy Dispersive X-ray Analyses (EDAX) to size and quantify elemental composition.
  - Low Temperature Ashing
    - Microscopically identify minerals present
  - Chemical Fractionation
    - Provides information on Organically Bound elements
  - Elemental Analyses of float sink and/or size fractions
    - Can be performed by ASTM coal laboratories
    - Pounds of iron per million Btu
    - Pounds calcium, sodium, and other elements

Ash Deposit Analyses

- Sampling Procedure for Ash Deposits
- Polarized Light and Scanning Electron Microscopy
  - Look for the glue holding the material together
  - Look for signs of combustion conditions

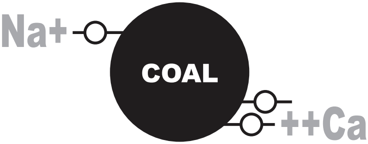
Forms of Iron by chemical fractionation

Mossbauer spectroscopy

Fouling Deposit Formation

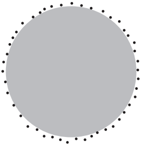
Organic calcium and sodium elements vaporize during combustion

Organically Bound Alkalis

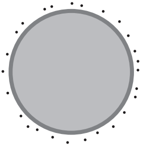


The calcium reacts with sulfur gases to form calcium sulfate. Sodium can condense onto aluminosilicate flyash particles and melt the surface

Sodium Condenses on Surface



Causing a Molten Layer on Surface



Electrostatic Precipitators

Basic Operation Principles

High Voltage DC – Transformer Rectifier Sets

Voltage Control – Controlling the wave from and sparking rate

Sizing ESP – Plate area (fixed) and Flue gas volume (operational variable?)

Migration Velocity or why the particle goes to the plate

Ash Resistivity concerns

Gas Velocity – impacts ESP size and treatment time

Rapping – important equipment that can be high maintenance

Advanced ESP Methods and Tune-up

Combustion Influences

ESP is meant to collect ash, not carbon from incomplete combustion

Resistivity, volume of material, and potential fires all point towards

- spending time on combustion
- Air in leakage and air heater leakage can significantly impact ESP performance

- Balancing furnace and flue gas flows
  - What do you balance, flow, temperature, excess air?

Calculating and Measuring Fly Ash Resistivity
- Calculation Methods
- Laboratory Measurements
- In situ Measurements
  - Cup Collection Method
  - Point to Plane Resistivity Probe

Correlating and making sense of resistivity data

Rappers
- Adjustment and different thoughts on rapping sequencing
- Inspections and Maintenance
- Measuring rapper force

High Voltage controls
- Spark rate theories
- Ramp rate, hold and setback settings

Measuring gas flows and particular loadings
- EPA Methods 5 and 17
- Hotwire anemometer

ESP Inspections
- Learn form your inspector
- Mechanical and Electrical

Tune-up Procedures
- Good Combustion
- Furnace conditions and temperatures
- Air Leakage
- Rapper Performance
- Balancing
- Voltage controls

Slag Fundamentals:
Understanding Boiler Slag Causes

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Introduction

The term slag dates back to at least 1552 as the lower middle German term Slagge. Sometimes referred to as clinker, dross, or scoria, it consists of molten rock and minerals and closely resembles volcanic ash and lava. Slag is miserable stuff. Molten ash deposits formed from burning coal increase O&M costs and forced outages at coal plants. Slag problems have plagued boiler operators from the start. A 1916 copy of the B&W Steam Book quotes “A large percentage of ash is undesirable as it chokes up air passages in the furnace. If the coal contains an excessive quantity of sulfur, trouble will result because it unites with the ash to form a fusible slag or clinker which will choke up the boiler.” This is the exact same thing we teach in 2009 coal combustion classes. Most coal miners we know will sell you rock and sulfur at the price of coal. The use of low NOx burners, higher sulfur coals, raw coals, and low rank coals have all increased slag formation. This Coal Combustion, Inc. paper deals with slag causes. There are many ways to minimize and control slag, too numerous for this short report.

There are two basic forms of ash deposits: 1) molten ash and 2) alkali sulfate salts. The molten deposits are called slag and occur primarily in the high temperature or furnace area of the boiler. The alkali salts generally occur in the convection or cooler portions of the boiler and duct work and are called fouling deposits. These two types of deposits are formed independently and have different causes, chemistry, and formation mechanisms. This paper covers slag.

Types of Slag: Wall Slag

Wall slag is the molten slag that builds up on the furnace walls. It is usually controlled by soot blowers using air, steam and in some cases water as a removal medium. Most boilers have some degree of wall slag and it does not necessarily cause problems. In fact, boilers that do not have enough wall slag due to a change to low slagging coal may have problems with maintaining steam temperatures. Low rank high calcium coals may produce a thin wall slag that is hard to remove and yet causes problems due to its reflective nature. Wall slag is caused by both operational and fuel related causes. The wall burners of a pulverized coal boiler are usually pointed at another water wall. If the velocity is too high and/or the particles are too big they will impact the wall across from the burner. Coal will burn away to gas as shown in Figure 53-1. Minerals in coal will move through the flame, melt, and hit the tubes of the water wall as shown in Figure 53-2.

Figure 53-1. Coal Burning

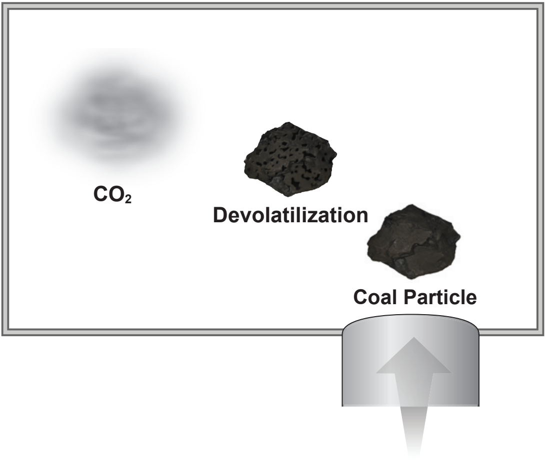
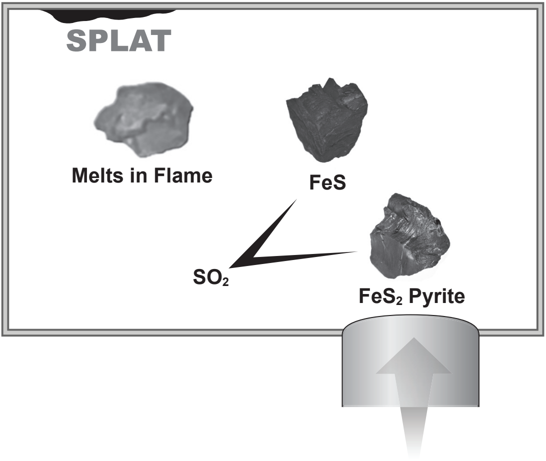


Figure 53-2. Wall Slag Formation



Excessive wall slag leads to the following problems:

1. Wall slag flows to the bottom of the furnace, cools and plugs the opening situated there. The ash eventually bridges over, sealing off the outlet for bottom ash removal.
2. Wall slag acts as an insulator and impedes heat transfer to the water wall. This increases the furnace exit gas temperature (FEGT) and allows molten ash to deposit in the superheater and convection pass regions.
3. Slag buildup around the burner regions, called eyebrows, interferes with the coal and air flow. This type of buildup can cause damage to the burners, among other things.

Superheater Slag

Superheater slags are molten deposits that form in the superheater and other convection sections of the boiler. These are particularly troublesome due to the blockage of the gas flow path and damage resulting from the fall of slag onto the lower furnace.

Causes of Slag

The main causes of ash deposits depend on where you work. If you work in steam plant operations the main cause is lousy coal, if you are a coal buyer the main cause is lousy steam plant design, and if you are in engineering the main cause is lousy steam plant operation. All are right in a sense. Scientific analytical investigations reveal that it is usually a combination of all three of these areas.

Slag is primarily caused by elevated concentrations of the main fluxing elements: iron, calcium, and sodium. This can be from high concentrations in the ash and/or high ash levels. The iron based slags (think high sulfur) are very sensitive to the amount of carbon (LOI) and/or carbon monoxide (CO)levels, and become wetter and stickier when found in a reducing (fuel rich, low NOx) environment. Hence almost all iron based slags can be made more controllable if there is a combustion tune-up that minimizes the carbon and CO levels. Large particles of the iron based mineral pyrite also behave poorly as they are harder to burn than smaller particles.

Slag is also caused by fluxing with calcium and/or sodium. These elements are not as influenced, as iron is, by the combustion conditions. The total amount and concentration of these elements appears to offer the best correlation to problems encountered at generating units.

TABLE I - Major Causes of Ash Deposits
The following table presents the major causes of ash deposits:

Fuel Related	Large pyrite particles that impact the furnace wall before they completely combust
	Clay minerals that contain significant amounts of iron, calcium, sodium or potassium causing them to have low melting temperatures
	Interaction of pyrite, clays and alkalis with alumino silicates to form low viscosity melts
	Extremely fine or organically bound alkalis, sodium and calcium
	Firing low reactivity fuels that introduce unburned carbon into slags with elevated iron (Fe_2O_3) concentrations
	An increase in concentration of any of the materials listed above
Equipment Related	Soot blowers and other deposit removal equipment not in operation or used improperly.
	Poor pulverization of fuel
	Improper air to fuel ratio
	Burners damaged or improperly adjusted
	Changes in operation of boiler or other equipment
Design Related	Furnace size too small for fuel
	Tube material and/or spacing inadequate
	Soot blowing and ash removal coverage inadequate
	No means provided to observe slag buildup

Analytical Procedures for Slag

Coal ash slag is sophisticated material. It covers a wide range of mineralogical transformations including glass formation, devitrification (crystals that form on cooling of glass), changes in oxidation state, and reactions between individual minerals at high temperature. We begin with an overview of coal mineralogy and its relationship to coal ash chemistry, melting and slagging properties, and fusion temperatures.

There are not distinct melting points for coal ash like with ice or other pure compounds, so when melting is mentioned it is used to represent a decrease in viscosity, rather than a melting point. When coal ash melts it occurs on both a large scale and a microscopic scale. On the large or bulk scale the ash behaves like a glass. As the temperature of the material increases, its viscosity decreases. At temperatures less than 2000° (F.) the ash may appear solid, or at least stiff, such as a Tootsie Roll. On a microscopic scale several minerals may have already melted, but their concentrations are low when compared to other minerals with higher melting temperatures. As the temperature is increased the ash becomes less viscous or more liquid-like. Many reactions are now occurring between the minerals as they melt and become more fluid. As the molten components mix they become more like molten glass. This molten material starts to dissolve the non-molten materials like quartz and other minerals. In this way the melting temperature of minerals such as sandstones and shales are lowered by other minerals such as pyrite and limestone.

Ash Fusion Temperatures

The Ash Fusion Temperature Test is a documented observation of the above process occurring in coal ash shaped like a small cone, and placed in a furnace with increasing temperatures. The initial deformation temperature, ID, is usually a hundred or more degrees above where the first low melting temperature minerals start to melt. The remaining fusion temperatures represent an ever increasing amount of molten material, and a lowering of the viscosity of the glass-like material. It should be noted that even at the fluid fusion temperature there may be solid or non-melted minerals such as quartz. The atmosphere of the furnace is controlled to either an oxidizing (like air, good combustion) or a reducing (CO and carbon present, poor combustion) condition. This is important due to the oxidation behavior of iron (Fe) atoms. Reduced iron lowers melting and fusion temperatures of ash much better than the oxidized form. In coals that have significant iron levels, usually those coals with elevated sulfur content, the oxidation state of the iron is critical. The difference between the oxidizing and reducing fusion temperatures can be hundreds of degrees. This phenomenon is one of the variables that make consistent fusion temperature data hard to obtain. It is also why some fuels are sensitive to Low NOx firing conditions that create an excessively reducing environment, good for NOx, bad for slag. The firing of low reactivity fuels such as petroleum coke can also add significant amounts of carbon to the slag material, making it become wetter and stickier than when in an oxidizing environment.

The fusion temperature test is a lower cost technique with reasonable turnaround time. Fusion temperatures have been used for years, and are contained in most coal contracts. Unfortunately, ash fusion temperatures provide no mineralogical information, are notoriously imprecise, and are influenced by all sorts of factors that cause variability. It is the author's experience that different laboratories can produce fusion temperatures that vary well outside the STANDARD TESTING ORGANIZATION guidelines, and both laboratories are performing satisfactorily.

Major and Minor Elements in Coal Ash

(Improperly termed ash mineral analyses, AMA by most major laboratories)

When trying to determine the behavior of coal ash in a boiler, both the type and size of minerals present is important information. This can be performed using Computer Controlled Scanning Electron Microscopy (CCSEM), x-ray diffraction, and other advanced techniques. Unfortunately, it is both difficult and expensive to determine the actual minerals in coal. The ash chemistry or Major and Minor Elements in Coal Ash test is the next best test. This is because melting properties can be estimated and minerals can be inferred. Although the cost of ash chemistry is higher than fusion tests, the information obtained is well worth the expense. The following elements are normally reported (as oxides) in the STANDARD TESTING ORGANIZATION Major and Minor Elements test.

Acids or glass formers (add bulk to the deposit)

Silicon dioxide . . . . SiO_2
Aluminum oxide . . . . Al_2O_3
Titanium dioxide . . . . TiO_2

Base or fluxing agents(act as bonding agents)

Iron oxide . . . . Fe_2O_3
Calcium oxide. . . . . CaO
Magnesium oxide . . . . MgO
Potassium oxide. . . . . K_2O
Sodium oxide . . . . Na_2O

There are several well-recognized slagging calculations that can be performed using the results of the STANDARD TESTING

ORGANIZATION Major and Minor Elemental or ash chemistry test. The simplest is the base to acid ratio, (B/A) that compares the amount of basic (or fluxing/bonding) elements to the acidic (or glass formers/bulk) elements.

$$B/A = \text{Sum of bases/sum of acids} = \frac{(Fe_2O_3+CaO+MgO+K_2O+Na_2O)}{(SiO_2+Al_2O_3+TiO_2)}$$

The ash is dry and has high fusion temperatures when the B/A is low. As the concentration of the fluxing elements increases, the ash becomes stickier and the ash fusion temperatures begin to decrease. There is a point above B/A=0.5 where the fusion temperatures reach a minimum, and further increases of the B/A above 0.75 only increase the amounts of fluxing or bonding material rather than meaningfully influence the fusion temperatures.

There is a well documented Slagging Index that uses the B/A multiplied by the percentage dry sulfur.

Slagging index = Dry sulfur x B/A

As the Slagging Index increases the slagging potential of the coal is deemed to increase. This calculation is in effect an iron squared [$(Fe_2O_3)^2$] term. This is because the B/A has Fe_2O_3 on top and the dry sulfur content has a pyritic component that increases proportionally to the total sulfur. The use of this Index is generally limited to high sulfur coals but could be used on any coal that has significant (>~0.5%) iron pyrite levels.

The concern about all of the above tests is that they do not incorporate the amount of ash present in the system.

Any experienced plant operator will soon realize that if you take the same fusion, B/A, etc. and double the amount of ash, he could have a real situation on hand controlling deposit build ups.

There have been several good methods developed by American Electric Power and Alstom (CE) that use a chart that correlates the ash loading, fusion temperature, and B/A to a slagging potential or cleanability index. Our approach at Coal Combustion, Inc. is to rate the slagging potential to the ash and the main bonding elements iron, calcium, sodium on a pound per million Btus (lb/MBtu) basis. This methodology can easily be applied to any heat units whether English, Metric, or other. So whether you use Btu/lb, Calories/gram, Kcal/Kg, or Joules/Kg the same theory applies that we need to put coal quality data in the form that the boiler sees it. Boilers don't need percent, they need energy. The laboratory procedures (ASTM, ISO) require labs to put levels in percent. It is our job to convert levels to an energy basis. This is easily done.

Ash Loading and Elemental Loading

Ash levels

Ash levels in coal are generally reported from the lab as a percent of ash. This is convenient for the lab but not completely representative of what the boiler sees. Boilers demand Btus, not tons of fuel. A more representative (for the boiler) way to express ash levels is to use pounds of ash per million Btu. These units are easy to calculate using the following expression:

Lb. Ash/MBtu = %Ash/(Btu/lb./10,000)

The author has, on numerous occasions, found that the ash deposits formed in utility-sized boilers correlates best with ash and elemental loading data, rather than fusion temperatures or traditional slagging and fouling indices.

Basic or Bonding Elemental Loading
    Pounds of iron per million Btu
    Pounds calcium, sodium, and other elements

The coals are then compared on a total ash and elemental loading level basis. This procedure works well as indicated in the example below, only if the combustion system is tuned up and there are not excessive carbon and combustion issues.

Slagging with Bituminous Type Ash - High Iron

This example will show how a utility was able to lower its ash fusion specification by understanding how different coals behave in the boiler. Typically utilities have specifications, for total ash (in percent) and a fixed fusion temperature spec. Published accounts of utilities experience in this area have led many slag specialists to consider the amount of ash loading to be important. When ash levels are expressed in pounds per million Btus, they more closely reflect the levels seen by the boiler. The author has also proposed that the Iron loading (lbs.Fe_2O_3/MBtu) level is an important consideration. In several Eastern/ Midwest US coal slagging events worked on by the author, the problematic coal had elevated iron loading levels. Using this information, several utilities have conducted test burns of coals with lower fusion characteristics. Their strategy was to limit the iron loading by considering lower ash, higher iron coals. These coals had lower-than-design fusion temperatures but it was suggested that the lower ash levels would offset this. The results of the test confirmed that the iron loading levels more accurately predicted the slagging behavior of the coal than the fusion temperature of the coal. Other utilities using lower ranked bituminous and sub-bituminous coals have observed that deposit formation correlates well with calcium and sodium levels as expressing in Lbs/MBtu or Kg/MJ.

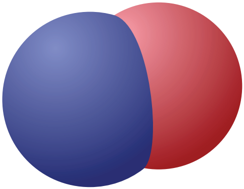
Conclusion

This paper was written to explain our understanding of coal slag. While not complete or sophisticated, we feel that the information presented here will assist you in resolving your slagging concerns. The science and technology of slag formation is complicated and not completely understood, and influenced by many factors, including where you work. We encourage others to share their experiences publicly. Together we can learn.

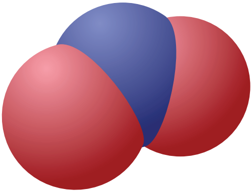
Combustion Management to Achieve Lower NO_x

THE MECHANICS OF NOx FORMATION

NOx generated by coal combustion is a combination of nitric oxide (NO) and nitrogen dioxide (NO_2). NOx in flue gas from coal combustion is 90% to 95% NO.



Nitric Oxide, NO



Nitrogen Dioxide, NO_2

Fuel NOx

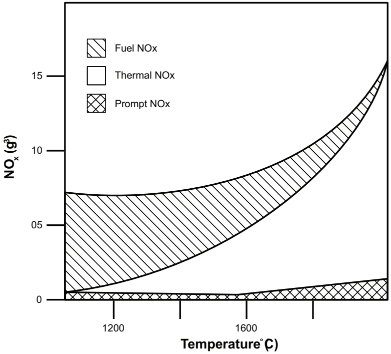
Fuel bound nitrogen and oxygen in the combustion air react to form NOx. All mechanisms that form fuel NOx are not fully understood at this point in time. What is known is that nitrogen in coal is responsible for approximately 80% of the total NOx formed during coal combustion which makes this the largest source of NOx production on a PC boiler. American coals are typically between ~0.25% to 1.5% nitrogen. If complete conversion of all fuel nitrogen took place, this would result in NOx emissions of 0.4 to 2.6 lb/MMBtu. During the normal combustion process only 20% to 30% of the N_2 content in fuel is converted to NOx. The conversion of fuel nitrogen is weakly temperature dependent but depends strongly upon local burner stoichiometry.

Thermal NOx

Molecular nitrogen (N_2) and oxygen (O_2) both in the combustion air react to form thermal NOx at the high temperatures of the flame core. Atmospheric air utilized to provide combustion air for a coal flame is ~20.9% O_2 and 78% N_2. Naturally occurring nitrogen in air is basically inert, however, temperatures above ~2800°F cause thermal dissociation of N_2 and O_2 allowing nitrogen to combine with oxygen, creating primarily NO molecules. The rate of reaction that forms thermal NOx is highly dependent upon peak flame temperature and the stoichiometric ratio in the primary combustion zone (i.e. @ burners). The maximum thermal NOx production occurs at a slightly fuel lean mixture due to the abundance of oxygen in the hottest regions of the coal flame. The rapid decrease in NOx formation for either fuel rich or lean combustion indicates that control of stoichiometry at the burners is critical to achieving reduction in thermal NOx. Flame temperature decreases rapidly along the length of the flame as heat is radiated away from the flame resulting in almost all of the thermal NOx generated at the flame core.

Figure 54-1 illustrates relative NOx emissions and the temperature dependence of the three (3) sources of NOx for coal combustion. These relationships make precise control of burner stoichiometry mandatory for optimization of NOx emissions.

Figure 54-1 -- NOx Sources Versus Temperature



Thermal NOx formation can also increase as furnace heat release increases. Non-optimum combustion results in lower boiler efficiency which in turn requires more fuel to be fired to maintain unit electrical generation or steam flow. Lower boiler efficiency and higher fuel flows result in higher furnace heat release, which in turn, increases furnace gas temperature, promoting the formation of thermal NOx. Consequently, it is important to maintain optimum combustion which reduces heat rate and increases boiler efficiency to achieve further reductions to NOx.

Prompt NOx

Prompt NOx is typically insignificant, producing <5% of the total NOx formed during coal combustion. Prompt NOx is only significant in very fuel rich flames, which are inherently low producers of NOx due to reduction in thermal and fuel NOx. Prompt NOx is formed during the earliest stages of combustion in the flame zone through intermediate formation of fixed species of nitrogen that oxidize to NO, such as hydrogen cyanide (HCN), nitrogen monohydride (NH), dihydrogen cyanide (H_2CN), etc.

COMBUSTION MANAGEMENT

NOx emissions on pulverized coal fired (PC) boilers are increasingly being managed through the use of flue gas treatment technologies (i.e. SCR and SNCR). However, opportunities exist for managing NOx by optimizing boiler side or “combustion” side parameters. Optimized combustion includes control and management of the secondary airflow, balancing the primary air and fuel flow to the burners, burner tuning and burner tilts (tangential fired boilers) and pulverizer performance. Managing the combustion inputs should be the first step towards NOx reduction.

Secondary Air flow

NOx emissions can vary significantly under transient load conditions if primary and secondary air flows are not accurately controlled. Secondary (combustion) air distribution to each burner, burner compartment or burner corner should be balanced to within ±5% deviation from the mean. Precise, repeatable and predictable control of NOx requires accurate measurement and control of both pulverizer primary air and secondary air. Accurate on-line measurement of secondary air is only typically found on units with compartmentalized windboxes. When boiler design does include windbox compartmentalization and flow measurement elements, it is imperative that flow measurement devices, whether they be air foils, pitot arrays, flow nozzle or venturi(s), be periodically calibrated by local hot “K” factor traverses. Common mechanical, maintenance or operational variables that cause burner secondary air imbalances are:

- Air register settings
- Non-representative external indication of burner sleeve, shroud or register position
- Windbox damper stroking or actuator malfunction
- Windbox aerodynamics
- Windbox/casing leaks
- Non-optimum distribution of overfire, boundary or curtain air
- Balancing economizer exit O_2 by burner adjustment when O_2 split is caused by localized boiler setting air in-leakage

- Air heater leakage or partial pluggage
- Imbalances originating from F.D. fans

Primary Air Flow

Fuel flow to each burner should be balanced within ±10% deviation from the mean. Our experience has indicated that high primary air flow can both increase NOx emissions and contribute to non-optimum combustion. Increased NOx emissions caused by high primary air flow are often the result of the following:

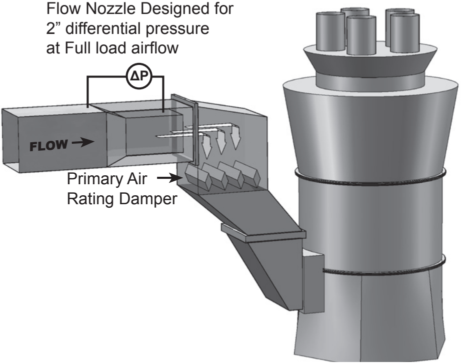
- **Flame Detachment (ignition points far from burner nozzle tip).** The most critical part of a low NOx burner flame is the region of the flame close to the nozzle, as the near burner conditions control the flame's overall NOx production. In the "near burner" region of the flame, the fuel N_2 (largest producer of NOx) in the volatile fraction of the coal must be released into an atmosphere lacking O_2. To ensure this occurs, the flame must be attached to the burner nozzle, since high primary air flow tends to push ignition points out into the furnace. Flame attachment not only controls the near burner air/fuel ratio, but enhances the devolatilization of coal hence the release of fuel N_2 into this critical reducing zone of the flame.

- **Injection of excess oxygen into the high temperature flame core.** High primary air flows force more O_2 into the flame core making more oxygen available for the conversion of nitrogen to nitric oxide.

- **Increases in primary airflow correlate to an increase in velocities at the classifier outlet of the pulverizer.** Higher velocity air at the classifier outlet has sufficient energy to entrap larger, more massive coal particles, which results in poor coal fineness. Lower velocities allow larger particles to be returned to the pulverizer grinding zones. High primary airflow also increases the velocity differential between primary air and secondary (combustion) air. This delays combustion, allowing a large percentage of heat to be released above the burner belt zone instead of being absorbed by the lower water walls. This high heat release elevates furnace exit gas temperatures which increases slagging propensity.

The importance of accurate measurement and control of the primary air cannot be emphasized enough. ICT prefers utilization of a flow nozzle (shown in figure 54-2) when possible. If flow nozzles are not installed, primary air flow measurement accuracy must be within ±5% of actual flow.

Figure 54-2 PA -- Flow Nozzle Schematic



Low Excess Air Operation

Optimum combustion or complete burnout of all oxygen to carbon monoxide and all hydrogen to water is at odds with NOx formation. Excess oxygen is required in the furnace to ensure stoichiometic combustion. However, too much oxygen will increase the formation of NOx. If the combustion air is reduced too much, it can result in poor fuel-air mixing creating CO and soot emissions. On high heat release units, NOx is often marginal and excess air must be lowered to the least possible quantities without excessive CO emissions or flyash loss on ignition (L.O.I.). The effects of reducing excess air on thermal NOx generation and unit performance is case specific with varying effects caused by furnace retention time (height of furnace cavity), furnace heat release, burner heat input and burner placement. Achieving the best possible balance in fuel and air will allow the lowest possible excess air level without unacceptable CO emissions, high carbon in ash and/or localized furnace slagging. This means that opportunities to balance fuel and air flows is case specific and differs between individual boilers.

Burner Tilts

On tangentially fired boilers, burner tilt position sometimes significantly effects NOx emissions. Typically, NOx emissions increase as burner tilts are elevated due to increased interaction of fuel-rich streams with air through the close coupled overfire air compartments or upper auxiliary air compartments. Downward orientation in burner tilts also results in other favorable boiler performance factors, including:

- Lower slagging propensity with downward orientation of burner tilts at full load due to furnace exit gas temperature depression by increased lower water wall heat absorption
- Higher furnace retention time, allowing for enhanced carbon burnout and improved flyash Loss on Ignition
- Increased homogenization of flue gases for uniform tube metal temperatures and flue gas O_2

Combustion conditions and heating surfaces must be evaluated and optimized if full load operation with acceptable steam temperatures can not be maintained at slight downward orientation of burner tilts. Often burner tilts are used as a means to balance furnace O_2 at the boiler or economizer exit. Employing tilts to balance O_2 is only masking a furnace oxygen imbalance and is not the corrective action that attains maximum boiler performance. When tilts are utilized to balance O_2, this is indicative of O_2 imbalances caused by localized boiler setting air in-leakage or fuel and/or air imbalances at the burners.

Staging of Combustion Air

Staging of combustion air includes methods for introducing combustion air into the boiler other than through the in-service burners. The intent is to separate the primary air from the secondary air to delay combustion and encourage the formation of N_2 rather than NOx and to also reduce oxygen at the hot burner flame core to discourage the formation of thermal NOx. Methods that have been used historically include overfire air, simulated overfire air and boundary air.

Overfire Air

Several types of low NOx systems for wall fired and tangentially fired boilers utilize overfire air to reduce NOx emissions. The configuration and delivery of overfire air is unit specific and varies greatly between different boilers. However, the principle and mechanisms through which NOx is reduced are essentially the same. Reduction in NOx with overfire air is facilitated by pyrolysis of coal in an oxygen deficient high temperature atmosphere in which fuel bound nitrogen evolved from the coal is converted to N_2 rather than NO combined with reduction in thermal NOx by ensuring an oxygen deficiency in the hot flame zone. This is followed by the introduction of the remaining air required to completely burn the coal without forming excessive amounts of NO because the bulk of oxidizable organic nitrogen has already been converted into innocuous molecular nitrogen. On systems that utilize overfire air, overfire air is typically 20% of the total air for combustion to attain maximum NOx reduction with acceptable combustion. Decreases in overfire air typically increase NOx emissions and decrease L.O.I. This is the result of allowing a higher proportion of air to pass through the burners where the exposure or retention time of coal derived carbon to excess air is maximized. Increases in overfire air often increase furnace exit gas temperature. This is caused by staging or delaying combustion which elevates the center of combustion in the furnace exposing less water wall heating surface to the active combustion zone, subsequently reducing total heat absorption by the walls. The heat unabsorbed by the water walls must be absorbed by de-superheating spray flows or raising boiler exit gas temperatures. Lower burner belt stoichiometry is also less forgiving to fuel and air imbalances in the lower furnace, exacerbating localized slagging in the burner zone which seasons water wall surface, leading to further increases in furnace exit gas temperature.

Units are often found to be operating at NOx levels far below legally mandated levels due to higher than required overfire air flow. This is sometimes favorable when system averaging of NOx emissions is being exercised, however, it is often detrimental to the boiler and combustion efficiency. While excessive amounts of overfire air will reduce NOx, this comes at the expense of very low burner zone stoichiometry which can lead to tube wastage, slagging, aggravation of coal-ash corrosion, high carbon in ash, burner component overheating and excessive side to side O_2 or tube metal temperature variation and high de-superheating spray flows.

On corner fired units, dissimilar proportioning of over fire air flow between separate corners must be avoided through careful control of measurement of overfire air flow to each corner. Disproportionate distribution of overfire air flow between separate corners will result in some burner corners operating at a different stoichiometry than the remaining corners. This could feasibly result in the bulk of NOx emissions originating from one burner corner. Lower NOx and improved combustion would be realized through more effective utilization of overfire air if it were equally distributed. Equal distribution of overfire air flow and uniform stoichiometry in each of the burner corners is critical to achieving optimum combustion as well as optimizing unit NOx emissions. To prevent the adverse effects of overfire air, it is important that the overfire air be accurately measured and controlled precisely. This is facilitated by accurate flow measurement elements and frequent calibration by local traverse by proficient field test personnel. As a goal, overfire air should be accurately measured and controlled to within ±3% deviation from the mean.

Simulated Overfire Air

On wall fired boilers that have not been retrofitted for overfire air, some plants have substituted the use of an out of service upper pulverizer to inject additional combustion air into the furnace. This technique involves shutting off the fuel flow to a top row of burners and maintaining air flow through them in order to achieve a simulated overfire air effect. Just as with the retrofitted overfire air ports, the benefits are not without cost as low burner stoichiometry is still an issue. Additionally, generation requirements at most plants preclude the use of operating with pulverizers that are out of service for extended periods of time.

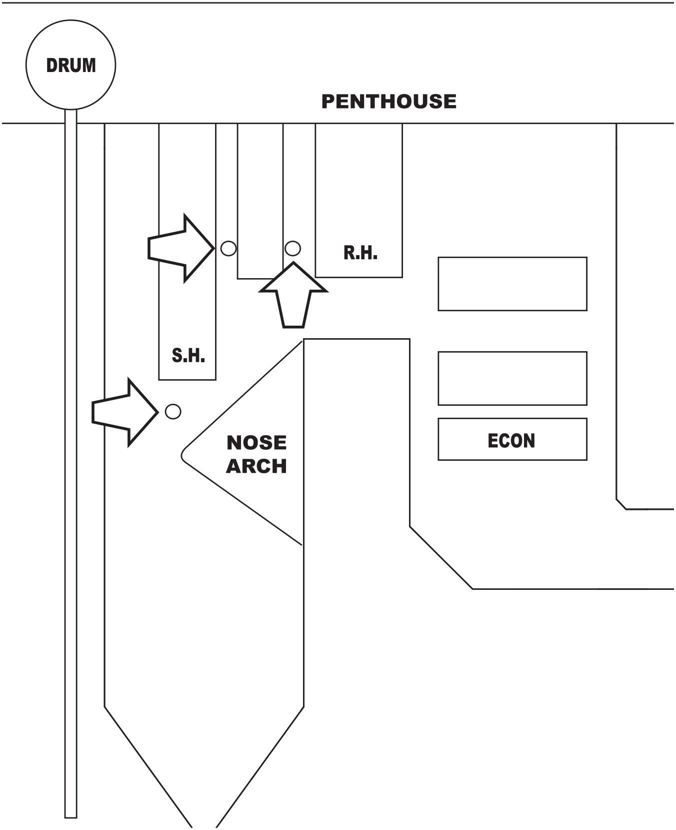
Boundary (Curtain) Air

Some low NOx burner systems utilize “Boundary” or “Curtain” air to reduce localized areas of reducing atmosphere that promote slagging, corrosion and tube wastage or as a NOx reduction technique. Boundary air is typically introduced through the boiler's lower dead air spaces or through openings below or around the burner zone periphery. Great care is usually taken to meter and control combustion air and pulverizer primary air with little attention to control quantity of boundary or curtain air flow. In some cases, excessive amounts of boundary or curtain air are experienced due to lack of measurement or control. This method of combustion air staging is not as common due to the fact that if the boundary air is excessive, the burners can become combustion air starved leading to high carbon in the ash, localized slagging, excessive furnace O_2 stratification, burner component overheating, as well as other adverse effects on performance.

Furnace Stoichiometry

Precise control of furnace stoichiometry is critical in any system that reduces NOx emissions through combustion controls. Furnace stoichiometry is typically controlled by oxygen analyzers at the boiler exit or economizer exit. Oxygen measurement at the boiler exit can often be inaccurate due to air in-leakage through the penthouse, nose arch dead air spaces, expansion joints and casing. Often boiler exit oxygen is 2.5% to 4% higher than furnace O_2 due to dilution of flue gas with ambient air in-leakage between the furnace exit and boiler exit. This results in 0% to 1% oxygen in the furnace cavity which is insufficient to facilitate complete combustion of carbon and can result in slagging, fouling, tube wastage, aggravation of coal-ash corrosion and other adverse effects. Quantifying air in-leakage or the relationship between furnace O_2 level and boiler exit oxygen should be considered of paramount performance on any unit utilizing low NOx burners. Furnace O_2 is usually ascertained using a water-cooled HVT probe at the furnace exit which is also used for accurate quantification of furnace exit gas temperature. Low NOx burners by design are fuel rich at the flame core. Test measurements within the flame envelope of a low NOx burner indicated that a short distance downstream on the burner, burner flue gas was 10% to 15% or 100,000 to 150,000 ppm carbon monoxide. An oxidizing furnace exit is mandatory for complete carbon burnout and the eradication of CO.

Figure 55-1 – Locations for Insertion of a HVT Probe



Burner Line Air and Fuel Imbalances

Combustion management and optimization naturally includes the pulverizer's contribution of fuel and air to each burner. The primary air is responsible for drying the coal and pneumatically transporting the fuel to the burners. The resulting two-phase fuel / air mixture must be balanced in each individual burner line to facilitate proper mixing at the burners and to prevent imbalances in the furnace that would impede stoichiometric combustion. Primary air to each burner (dirty air flow) should be accurately measured and controlled to within ±5% deviation from the mean. Common mechanical, maintenance or operational variables that cause non-uniform combustion as a result of burner line fuel and/or primary air imbalances related to the pulverizer are:

- Non-synchronous opening of classifier blades on centrifugal classifiers
- Excessively worn classifier blades
- Excessive erosion or non-optimum length of the classifier outlet skirt or deflector
- Eroded through holes in classifier cones
- Excessively worn riffle
- Non-optimum riffle configuration or orientation
- Poor coal fineness
- Absence of coal line orifices to balance burner line air flow or worn orifices
- Obstructions in burner lines from repairs of eroded elbows
- Non-uniform or non-optimum spring force on grinding elements

Pulverizer Coal Fineness

Proper sizing of coal transported through the burner lines is mandatory to achieve low NOx formation with low NOx systems without unacceptable levels in unburned carbon in flyash. Fineness is a primary mechanism for controlling flyash L.O.I., however, it is also required to enhance rapid devolatilization of coal in which the burners depend upon to reduce NOx. Low NOx is facilitated through lower burner stoichiometry, less intense mixing of air and fuel at the burners, combustion staging or low excess air. All of these factors provide less abundance of O_2 in close proximity to the coal, making complete combustion of char carbon more difficult. Due to this, previous fineness standards, which were typically 70% passing 200 Mesh and <1% remaining on 50 Mesh, must be increased to higher levels to compensate for less intense combustion associated with low NOx burner systems. Increases in coal fineness almost always result in more even distribution of coal between separate burner lines. More even distribution of coal results in more precise control of burner stoichiometry that is critical to reducing NOx and achieving the best possible burner performance. Some units are more or less forgiving to fineness depending on coal quality, furnace geometry and burner configuration. In all cases, a minimum of >75% passing 200 Mesh and less than 0.3% remaining on 50 Mesh should be maintained with low NOx firing.

Boiler Cleanliness

NOx emissions can vary greatly as ash or slag deposits build up on water walls or in the burner zone which increases furnace exit gas temperatures (FEGT) or local flame temperatures. All wall deslaggers and sootblowers should be operable with frequent maintenance and functional checks. Optimum sootblowing practices are also mandatory to prevent excessive furnace slagging or fouling. The following actions should be taken to ensure optimum furnace cleanliness:

- Ensure retractable (IK) sootblowers that clean the bottom side of the nose arch are operable and have a local steam blowing pressure of 200 to 225 PSIG. This is some of the most effective surface in the furnace. Sootblowers that clean the bottom of the nose arch are typically effective in reducing furnace exit temperature by 100 to 150°F (38-65°C). These blowers will also be effective in reducing reheater or superheater de-superheat spray flows.
- Ensure wall deslagger poppet valves are set to maintain a minimum blowing pressure at the blower of 200 PSI, 225 PSIG on wall deslaggers if slagging is apparent.
- Ensure all sootblowers and deslaggers are functional.
- If slagging or high furnace exit gas temperature is apparent, change wall deslagger gear drive limit pin setting from 360° rotation (1 revolution) to 720° rotation (2 revolutions).

- Ensure lances are not warped or misaligned. Misalignment or warped lances will cause binding. Binding will limit rotation and result in improper cleaning.
- Ensure lance nozzles or orifice(s) in the steam ports are not misaligned, missing, worn or coated with deposits. Misalignment or missing nozzles will handicap efficient removal of deposits.
- Verify blowing arcs. Sootblowers and wall blowers with one or two steam ports will usually release the blowing medium within a predetermined segment of rotation. Insure blowing medium is released when steam ports are facing tube surfaces.
- Ensure poppet valves and lance nozzles/orifices are of optimum sizing to deliver appropriate quantity of blowing medium.
- If aggressive sootblowing is required to reduce FEGT and slagging, ensure all thermal drains are operating properly, steam line insulation is intact and steam line slope is proper for effective condensate removal to prevent tube erosion.

Coal and Ash Quality

When evaluating the effect of coal quality on NOx emissions, fuel nitrogen content and fixed carbon/volatile matter content are often monitored closely without a great deal of attention to other factors. It is important to remember that other coal variables such as moisture, grindability index and ash fusion temperatures are also critical to unit performance and emissions. Changes in the Hardgrove Grindability Index (HGI) or fuel moisture will have significant impact on pulverizer capacity and fineness. Degradation in fineness as a result of lower H.G.I. coal or increased moisture can cause slagging problems, degradation in fuel balance and pulverizer surging which leads to less desirable NOx emissions and higher flyash L.O.I. Classifier changes, increased grinding element spring pressure, grinding surface “blue-printing” or other maintenance actions may be required to compensate for lower HGI coals. Differences in ash fusion temperature significantly changes furnace slagging propensity. A slagged furnace will result in less water wall absorption and higher furnace temperatures which can cause NOx emissions to demonstrate a gradual upward trend. When evaluating ash fusion temperatures, reducing and oxidizing fusion temperatures should be ascertained. Depending on ash constituents, primarily iron oxides and pyrites, oxidizing ash fusion temperature may be anywhere between 50°F and 300°F higher than reducing. For bituminous type coals there is typically a 100° to 175°F differential between reducing and oxidizing fusion temperatures. To prevent slagging, the furnace exit gas temperature at the nose arch should be well below the ash softening temperature. Accurate determination of furnace exit gas temperature requires use of a HVT Probe to quantify temperature peaks. Infrared and optical type pyrometers may be able to quantify average furnace exit gas temperature, but are unable to determine localized peaks in flue gas temperature. Utilization of the HVT Probe also allows quantification of oxygen to ensure no localized areas of reducing or near reducing atmosphere are present.

What is a Successful Low NOx Burner Retrofit?

A low NOx burner retrofit should not be considered successful unless good combustion efficiency, unit efficiency and operability are achieved. Combustion efficiency is usually gauged by flyash Loss on Ignition, while unit efficiency is measured by heat rate which is affected by numerous variables such as spray flows, cycle losses, dry gas losses, draft losses, etc. Operability would be regarded as unit response, unit capacity, flame stability, stack opacity, ease of operation and absence of "excursions" in unit load, boiler pressure or steam temperatures. Achieving combustion uniformity in the burner zone is one of the most critical steps to achieving target NOx emissions and optimum performance; however, it is also one of the most difficult and time consuming endeavors. Achieving combustion uniformity in the burner zone includes the balancing of fuel, primary air and secondary air to each individual burner. Achieving high combustion efficiency with low NOx burners requires enhanced performance of each component in a combustion system. The combustion system includes burners, pulverizers, fans, all points of combustion air injection, boiler heating surface, the unit operators, and boiler maintenance personnel. Too often, boiler combustion is viewed from a macro perspective of total air to fuel ratio. Improvements are achieved by optimizing excess air and burner adjustments dictated by boiler exit gas species. Stratification at the boiler exit often show large variation in O_2, NOx and CO levels. The large gradient in the products of combustion (O_2, NOx and CO) is often caused by non-uniformity in combustion at the burners as a result of fuel and/or air imbalances. Individual burners create a multitude of local combustion zones that have vastly differing emission characteristics due to differing air to fuel ratios. Non-uniform combustion can lead to higher or non-repeatable NOx emissions. Maintaining uniform combustion requires uniformity in burner stoichiometry, which requires precise fuel and air balancing. Uniform combustion will result in similar heat release and emission characteristics of each individual burner. Non-uniform combustion can also result in other combustion related complications that lead to increased NOx emissions. Non-uniform combustion resulting from fuel and air imbalances in the burner zone are sometimes caused by mechanical or maintenance variables related to the pulverizers, burners, dampers or windbox. In other cases, non-optimum fuel balance or secondary air balance is inherent to the systems design and modifications must be made to reduce imbalances.

A-1. Clean Air Calculations

$$\text{Density}\ \ (\rho) = \frac{460 + 70°F}{460 + \text{T}(°F)} \times \frac{\left(Bp + \dfrac{Sp\ (\text{"w.c.})}{13.6\text{" } Hg}\right)}{29.92\text{" } Hg} \times 0.075\ lbs/ft^3$$

$$\text{Velocity} = 1096\,\frac{Avg\sqrt{vh}}{\sqrt{\rho}} \times Probe\ K \qquad Avg\sqrt{vh} = \frac{\sum_{vh=1}^{n}\sqrt{vh}}{n}$$

$$\text{\%Deviation/mean} = \frac{\text{Velocity - Average Velocity}}{\text{Average Velocity}} \times 100$$

Bp = Barometric Pressure ("Hg)

Sp = Static Pressure ("w.c.)

A-2. Coal Sampling Calculations

$$\text{Density}\ \ (\rho) = \frac{460 + 70°F}{460 + \text{T}(°F)} \times \frac{\left(Bp + \dfrac{Sp\ (\text{"w.c.})}{13.6\text{" } Hg}\right)}{29.92\text{" } Hg} \times 0.075\ lbs/ft^3$$

$$\text{Velocity} = 1096\,\frac{Avg\sqrt{vh}}{\sqrt{\rho}} \times Probe\ K \qquad Avg\sqrt{vh} = \frac{\sum_{vh=1}^{n}\sqrt{vh}}{n}$$

$$\text{\%Deviation/mean} = \frac{\text{Velocity - Average Velocity}}{\text{Average Velocity}} \times 100$$

$$\text{Volumetric Flow (Q)} = \text{Velocity(FPM)} \times \text{Pipe Cross Sectional Area}(\text{ft}^2)$$

$$\text{Mass Flow } (\dot{\text{m}}) = \text{Q(CFM)} \times 60(\text{min/hr}) \times \text{Density}(\text{lb/ft}^3)$$

Bp = Barometric Pressure ("Hg)

Sp = Static Pressure ("w.c.)

$$\Delta\text{P (Sampler Orifice during Sampling)} = 1.573 \times (\text{Avg}\sqrt{\text{vh}})^2 \times (\text{Probe K Factor})^2$$

$$\text{Coal Flow} = \frac{\text{Sample Weight (grams)}}{\text{453.6 grams/pound}} \times \frac{\text{60 minutes/Hour}}{\text{Total Sample Time (min)}} \times \frac{\text{Pipe Area - (ft}^2\text{)}}{\text{Sample Tip Area - (ft}^2\text{)}}$$

$$\text{Sample Tip Area} = 0.0021\text{ft}^2$$

$$\text{Air to Fuel Ratio} = \frac{\text{Air Flow in Pounds per Hour}}{\text{Coal Flow in Pounds per Hour}}$$

A-3. Airflow Calculations for Use with the Fecheimer Probe

$$\text{Density } (\rho) = \frac{460 + 70°F}{460 + T(°F)} \times \frac{\left(Bp + \dfrac{Sp\ (\text{"w.c.})}{13.6\text{" } Hg}\right)}{29.92\text{" } Hg} \times 0.075\ lbs/ft^3$$

$$\text{Velocity} = 1096\ \frac{Avg\sqrt{vh}}{\sqrt{\rho}} \times Probe\ K \qquad Avg\sqrt{Cvh} = \frac{\sum_{vh=1}^{n} \sqrt{vh}\ \cos^2\theta}{n}$$

$$\text{Volumetric Flow (Q)} = \text{velocity (FPM)} \times \text{duct cross- -sect. area (ft}^2\text{)}$$

$$\text{Mass Flow } (\dot{m}) = \text{Q} \times \text{60 min/hour} \times \text{Density}$$

$$\text{Device “K factor”} = \frac{\text{Mass Flow } (\dot{m})}{\sqrt{\rho} \times \sqrt{\text{Transmitter } \Delta P}}$$

A-4. Orifice Differential Calculations for Use with the Isokinetic Flyash Probe

h_o = ((A × 1096) / K_o)² × h_v

h_o = Sampler Orifice ΔP (“ w.c.)

A = Nozzle Inlet Area (ft²) = 0.0010084 ft²

K_o = Sampler Orifice Coefficient

h_v = Velocity Head (“ w.c.)

A-5. Calculations for Determining % Flyash L.O.I.

W_{CSD} = Crucible w/sample (dried weight)

W_{CSFW} = Crucible w/sample (final weight)

W_C = Crucible weight

$$\text{\% Flyash L.O.I.} = \left[\frac{(W_{CSD} - W_C) - (W_{CSFW} - W_C)}{(W_{CSD} - W_C)}\right] \times 100$$

A-6. Useful Coal Analyses Formulas

Dry = As Rec'd/(1 − (moisture/100))
MAF = As Rec'd/(1 − ((moist. + ash)/100)
MAF = Dry/(1 − (ash/100))

$/MBtu = $/ton/(2 × (Btu/lb/1000))

$$\text{Lbs } SO_2\text{/MBtu} = \frac{20{,}000 \times \%\text{Sulfur}}{\text{Btu/lb}}$$

Cost of Sulfur/ton of coal = 2 × (%Sulfur/100) × SO_2 Credit costs

Fuel Ratio = Fixed carbon/volatile matter

$$\text{Base to Acid Ratio, B/A} = \frac{(Fe_2O_3 + CaO + MgO + K_2O + Na_2O)}{(SiO_2 + Al_2O_3 + TiO_2)}$$

Slag Index = B/A × dry Sulfur

Lbs.Ash/MBtu = %ash/(Btu/lb/10,000)

Excess air = 20.9/(20.9 – O_2)

* The information on this page is used with permission from www.coalcombustion.com.

B-1. Terms Associated with Coal & Ash Analyses and Properties

As Received - Quality as received by the lab.

Dry - Quality with moisture mathematically removed.

MAF - Moisture Ash Free - quality of coal material as the moisture and ash have both been removed.

Slag - Molten ash deposit

Fouling - Deposit held together by salts (usually sulfates)

Rank - Terms used to describe basic types of coal i.e. Lignite, Bituminous, Anthracite

ASTM - American Society of Testing & Materials, a group that standardizes commonly used tests.

ASME - American Society of Mechanical Engineers

Proximate - Coal analyses that provides moisture, ash, volatile and fixed carbon percentages.

Ultimate - Coal Test that provides elemental data on carbon, hydrogen, nitrogen, sulphur and oxygen.

* The information on this page is used with permission from www.coalcombustion.com.

B-2. Approximation of Air Heater Leakage Using the Excess Oxygen Method

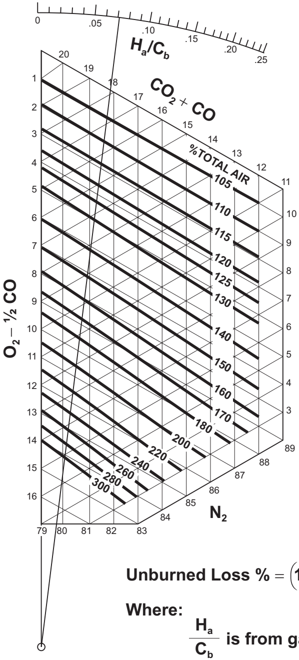
Although not a part of any code, an approximation of percentage of leakage may be obtained by the use of the percent volume of the O_2 in the gas entering and leaving the air heater. The formula is as follows:

B-3. Estimation of Total Boiler Air in Leakage

$$\%\text{Leakage} = \frac{(\%O_2\ \text{Entering} - \%O_2\ \text{Leaving})}{(\%O_2\ \text{Leaving} - 20.9\%)}\ \text{X}\ 90$$

O_2% From Boiler Outlet

Figure 56-1 -- Triangular Combustion Chart



Note: For complete combustion all points should be along a straight line drawn through the pivot point

GENERAL DATA

S.F.	
A.F.	

FUEL ANALYSIS

H	
O	
C	
Btu / lb.	
H_a / C	

$$\textbf{Unburned Loss \%} = \left(1 - \frac{H_a / C}{H_a / C_b}\right) \frac{C \times 14500}{\text{Btu / lb.}}$$

Where:

$\frac{H_a}{C_b}$ **is from gas analysis**

$\frac{H_a}{C}$ **Btu / lb. is from coal analysis**

C-1. Corrected Gas Temperature (No Leakage Basis)

$$\text{Air Heater Corrected Exit Gas Temperature} = \frac{(\text{Air Heater Leakage} \times Cp_{Air} \times (T_{Gas\ Out} - T_{Air\ In}))}{100 \times Cp_{Gas}} + T_{Gas\ Out}$$

Air Heater Leakage (%)

Cp_{Air} = Specific Heat of Air (Btu/lb °F)

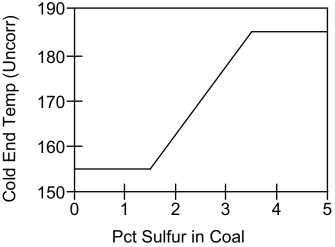
$T_{Gas\ Out}$ = Temperature of Gas Leaving Air Heater (°F)

$T_{Air\ In}$ = Temperature of Air Entering Air Heater (°F)

Cp_{Gas} = Specific Heat of Gas (Btu/lb °F)

C-2. Cold End Temperature

Minimum Average Cold End
Temperature versus Coal Sulfur



C-3. X - Ratio Calculation

$$\text{Air Heater X-Ratio} = \frac{T_{Gas\ In} - T_{Gas\ Out\ (No\ Leakage\ Basis)}}{T_{Air\ Out} - T_{Air\ In}}$$

$T_{Gas\ In}$ = Temperature of Gas entering Air Heater (°F)

$T_{Gas\ Out\ (No\ Leakage\ Basis)}$ = Air Heater Gas Outlet Temperature Corrected for No Leakage (°F)

$T_{Air\ Out}$ = Temperature of Gas Leaving Air Heater (°F)

$T_{Air\ In}$ = Temperature of Gas Entering Air Heater (°F)

Useful Formulas

D-1. Motor Torque Formula

$$\text{Torque (lb ft)} = \frac{\text{Horsepower} \times 5250}{\text{RPM}}$$

For Pumps:

$$\text{Horsepower} = \frac{\text{Flowrate (GPM)} \times \text{Head (ft)} \times \text{Specific Gravity}}{3960 \times \text{Efficiency of pump}}$$

For Fans:

$$\text{Air Horsepower} = \frac{\text{Flowrate (CFM)} \times \left[\left(P_{T2} - P_{T1}\right) + P_{L\,1-2}\right]}{6356}$$

P_{T2} = Total Pressure at fan discharge ("w.c.)

P_{T1} = Total Pressure at fan inlet ("w.c.)

$P_{L\,1\text{-}2}$ = Pressure loss from 1 to 2 ("w.c.)

$$\text{Drive Horsepower} = \frac{\text{Air Horsepower}}{\text{Fan Efficiency}}$$

D-2. Temperature Conversion

$$^{\circ}C = \left(\frac{5}{9}\right)\left(^{\circ}F - 32\right)$$

$$^{\circ}F = {}^{\circ}C \cdot \frac{9}{5} + 32$$

D-3. Electrical Formulas To Obtain Power in kW

$$\text{kW} = \frac{\text{Volts} \times \text{Amps} \times \text{Power Factor} \times \text{Phase Constant} \times \text{Efficiency}}{1000}$$

D-4. To Obtain Power in Horsepower

$$\text{hp} = \frac{\text{Volts} \times \text{Amps} \times \text{Power Factor} \times \text{Phase Constant} \times \text{Efficiency}}{746}$$

Where the phase constants are as follows:

Phase Constant = 1.0 for single phase

Phase Constant = $\sqrt{3}$ for three phase

D-5. Units of Power

1 kW = 1.3415 hp = 738 ft-lb/sec = 3413 Btu/hr

1 hp = .7455 kW = 550 ft-lb/sec = 2544 Btu/hr

D-6. Units of Work, Heat, Energy

1 Btu = 778.3 ft-lb = .0002930 kWhr = .0003931 hphr

1 kWhr = 3412.6 Btu = 1.3415 hphr

D-7. Expansion Coefficients for Commonly Used Metals in Boiler Construction

Carbon Steel	0.00000675 inch/inch/°F
Chrome Molybdenum	0.00000741 inch/inch/°F (up to 3% Chrome)
Type 304 Stainless Steel	0.00000992 inch/inch/°F

E-1. Fan Laws and Equations

Q	volumetric flow rate
D	fan diameter
N	fan speed
ρ	density
HP	fan input power
p	pressure (total, velocity, or static)
AHP	air horsepower

Varible	Constant	Fan Law
D	ρ, N	$Q_2 = Q_1\left(\frac{D_2}{D_1}\right)^3$ $p_2 = p_1\left(\frac{D_2}{D_1}\right)^2$ $HP_2 = HP_1\left(\frac{D_2}{D_1}\right)^5$
N	ρ, D	$Q_2 = Q_1\left(\frac{N_2}{N_1}\right)$ $p_2 = p_1\left(\frac{N_2}{N_1}\right)^2$ $HP_2 = HP_1\left(\frac{N_2}{N_1}\right)^3$
Q	ρ, HP	$p_2 = p_1\left(\frac{Q_2}{Q_1}\right)^{-1}$ $D_2 = D_1\left(\frac{Q_2}{Q_1}\right)^{\frac{3}{4}}$ $N_2 = N_1\left(\frac{Q_2}{Q_1}\right)^{-\frac{5}{4}}$
D	ρ, Q	$p_2 = p_1\left(\frac{D_2}{D_1}\right)^{-4}$ $N_2 = N_1\left(\frac{D_2}{D_1}\right)^{-3}$ $HP_2 = HP_1\left(\frac{D_2}{D_1}\right)^{-4}$
HP	ρ, D	$Q_2 = Q_1\left(\frac{HP_2}{HP_1}\right)^{\frac{1}{3}}$ $N_2 = N_1\left(\frac{HP_2}{HP_1}\right)^{\frac{1}{3}}$ $p_2 = p_1\left(\frac{HP_2}{HP_1}\right)^{\frac{2}{3}}$
p	ρ, D	$N_2 = N_1\left(\frac{p_2}{p_1}\right)^{\frac{1}{2}}$ $Q_2 = Q_1\left(\frac{p_2}{p_1}\right)^{\frac{1}{2}}$ $HP_2 = HP_1\left(\frac{p_2}{p_1}\right)^{\frac{3}{2}}$
ρ	Q	$p_2 = p_1\left(\frac{\rho_2}{\rho_1}\right)$ $HP_2 = HP_1\left(\frac{\rho_2}{\rho_1}\right)$

Example: Given a 40-inch diameter fan delivering 10,000 cfm at 900 RPM and 4 hp, find the fan speed and input power needed to produce 15,000 cfm.

$$Q_2 = Q_1\left(\frac{N_2}{N_1}\right) \longrightarrow N_2 = \left(\frac{Q_2}{Q_1}\right)^3 N_1 = \left(\frac{15{,}000\ cfm}{10{,}000\ cfm}\right) 900\ RPM = \boxed{1{,}350\ RPM}$$

$$HP_2 = HP_1\left(\frac{N_2}{N_1}\right)^3 = 4\ hp\left(\frac{1{,}350\ RPM}{900\ RPM}\right)^3 = \boxed{13.5\ hp}$$

Example: Given a 25-in. fan delivering 5,000 cfm at 1000 RPM and 4 hp, find the corresponding capacity and speed for a 30-in. fan for the same power consumption.

$$D_2 = D_1\left(\frac{Q_2}{Q_1}\right)^{\frac{3}{4}} \longrightarrow 30\ in = 25\ in\left(\frac{Q_2}{5{,}000\ cfm}\right)^{\frac{3}{4}} \longrightarrow Q_2 = \boxed{6{,}380\ cfm}$$

$$N_2 = N_1\left(\frac{Q_2}{Q_1}\right)^{-\frac{5}{4}} = 1000\ RPM\left(\frac{6{,}380\ cfm}{5{,}000\ cfm}\right)^{-\frac{5}{4}} = \boxed{737\ RPM}$$

Useful fan relationships

1. Capacity varies directly with fan speed.
2. Pressure varies with the square of fan speed or square of fan capacity.
3. Velocity varies directly with fan speed or capacity.
4. Fan speed and capacity vary with the square root of pressure.
5. Fan input power varies with the cube of fan speed or cube of capacity.
6. Fan input power varies with $(\text{pressure})^{3/2}$
7. For a constant speed, pressure varies with the square of the fan diameter.
8. For a constant speed, capacity varies with the cube of the fan diameter.
9. For constant capacity, pressure and fan input power vary directly with density.

$$AHP = \frac{p_f\,(in.wg)\ Q\,(cfm)}{6356} \quad where\ p_f = (p_{s2} - p_{s1}) + (p_{v2} - p_{v1})$$

$$HP = \frac{p_f\,(in.wg)\ Q\,(cfm)}{\eta_t 6356} \quad where\ \eta_t = is\ total\ fan\ efficiency$$

F-1. Maximum Allowable Stress Values for Frequently Used Boiler Tube Materials

Maximum Allowable Stress Values for Frequently used Boiler Tube Materials

Data from: ASME Boiler & Pressure Vessel Code 1986 **Section I Power Boilers**

Material Specification	Min. Tensile	700	800	900	1000	1050	1100	1150	1200	1300	1400	1450	1500	Material Type
SA-178-A	47,000	11,500	7,700	*	*	—	—	—	—	—	—	—	—	Carbon Steels C
SA-178-C	60,000	14,400	9,200	*	*	—	—	—	—	—	—	—	—	Carbon Steels C
SA-192	47,000	11,500	9,000	*	*	—	—	—	—	—	—	—	—	Carbon Steels C-Si
SA-209-T1	55,000	13,800	13,500	12,700	*	—	—	—	—	—	—	—	—	Low Alloy Steels C-½ Mo
SA-209-T1A	60,000	15,000	14,400	13,600	*	—	—	—	—	—	—	—	—	Low Alloy Steels C-½ Mo
SA-210-A1	60,000	14,400	10,800	*	*	—	—	—	—	—	—	—	—	Carbon Steels C
SA-210-C	70,000	16,600	12,000	*	*	—	—	—	—	—	—	—	—	Carbon Steels C-Mn-Si
SA-213-T2	60,000	14,200	13,500	12,800	*	—	—	—	—	—	—	—	—	Low Alloy Steels ½ Cr.- ½ Mo
SA-213-T9	60,000	13,700	12,300	11,400	7,400	5,000	*	*	*	—	—	—	—	Low Alloy Steels 9 Cr.- 1 Mo
SA-213-T11	60,000	15,000	15,000	13,100	6,600	4,100	*	*	*	—	—	—	—	Low Alloy Steels 1¼ Cr.- ½ Mo-Si
SA-213-T22	60,000	15,000	15,000	13,100	7,800	5,800	4,200	*	*	—	—	—	—	Low Alloy Steels 2¼ Cr.- 1 Mo
SA-213-TP-304	75,000	15,200	15,200	14,700	13,800	12,200	9,800	7,700	6,100	*	—	—	—	High Alloy Steels 18 Cr.- 8 Ni
SA-213-TP-304-H	75,000	15,200	15,200	14,700	13,800	12,200	9,800	7,700	6,100	*	—	—	—	High Alloy Steels 18 Cr.- 8 Ni
SA-213-TP-321	75,000	10,800	10,800	10,600	10,400	9,200	6,900	5,000	3,600	*	—	—	—	High Alloy Steels 18 Cr.- 10 Ni-Ti
SA-213-TP-321-H	75,000	15,500	15,500	15,300	14,000	11,700	9,100	6,900	5,400	*	—	—	—	High Alloy Steels 18 Cr.- 10 Ni-Ti
SA-213-TP-347-H	75,000	14,700	14,700	14,700	14,400	14,100	13,000	10,500	7,900	*	—	—	—	High Alloy Steels 18 Cr.- 8 Ni-Cb

*Not recommended for use at this temperature, considering oxidation, creep and experience

F-2. Boiler Tube Material Temperature Limits

Boiler Tube Material Temperature Limits			
Tube Material	**B&W**	**CE**	**ASME**
SA 213 (T22) 2.25 Cr. 5 Mo	1115	1075	1200
SA 213 (T11) 1.25 Cr. 5 Mo	1050	1025	1200
SA 213 304 SS	1400	1300	1500
SA 192 Low Carbon Steel	950	850	1000
SA 210 Med Carbon Steel	950	850	1000

F-3. Minimum Tube Wall Thickness Construction

MWT = [PD/(2S + P)] + (0.005 x D)

P = Maximum Design Pressure (PSI)
D = Outside Diameter of Tube (Inches)
S = Maximum Allowable Stress (PSI)
MWT = Minimum Wall Thickness (Inches)

F-4. Frequently Used Boiler Tube Alloys

Designation		Alloy Designation	Suggested outer Skin Temperature Limits	Chemical Composition %	Notes
ASME	ASTM				
SA-178 A	A178	Low Carbon Electric Resistance Welded	800°F	C .06 to .18 Mn .27 to .18 P .050 Max S .060 Max	Maximum Available Wall Thickness is .240"
SA-192	A192	Low Carbon (Seamless)	800°F	C .06 to .18 Mn .27 to .18 P .050 Max S .058 Max Si .25 Max	
SA-178 C	A178	Medium Carbon Electric Resistance Welded	800°F	C .35 Max Mn .80 Max P .050 Max S .060 Max	Maximum Available Wall Thickness is .240"
SA-210 A - 1	A210	Medium Carbon (Seamless)	800°F	C .27 Max Mn .93 Max P .048 Max S .058 Max Si .10 Max	
SA-209 T - 1	A209	Carbon Moly (Seamless)	900°F	C .10 to .20 Mn .30 to .80 P .045 Max S .045 Max Si .10 to .50 Mo .44 to .65	
SA-213 T - 11	A213	Chrom Moly (Seamless)	1000°F	C .15 Max Mn .30 to .60 P .03 Max S .03 Max Si .5 to 1.00 Mo .44 to .65 Cr 1.0 to 1.50	1 1/4 Chrome 1/2 Moly
SA-213 T - 22	A213	Chrom Moly (Seamless)	1075°F	C .15 Max Mn .30 to .60 P .03 Max S .03 Max Si .5 to Max Mo .87 to 1.13 Cr 1.9 to 2.6	2 1/4 Chrom 1 Moly
SA-213 TP 304H	A213	Stainless (Seamless)	1300°F	C .04 to .10 Mn .20 to Max P .040 Max S .03 Max Si .75 to Max Ni 8.0 to 11.0 Cr 18.0 to 20.0	18 Chrome 8 Nickel

G-1. BTU's from Fuel Burned from CEMS

$$HI = \frac{Q \times \%CO_2 \times 600{,}000}{F_C}$$

HI = BTU's from Fuel Burned in BTU's/ hour

Q = SCFM of Wet Flue Gas

$\%CO_2$ = Percent CO_2 - Wet Basis

F_c = Fuel Factor (Fuel Dependant)

EPA Value - 1800

Eastern Coal - 1850

G-2. SO_2, SO_3 Emissions from Boilers Firing Coal or Fuel

O_2:

$$\text{lb } SO_2 \text{ produced / lb fuel} = K\left(\frac{\text{lb sulfur}}{\text{lb fuel}}\right)\left(\frac{64 \text{ lb } SO_2 \text{ / mole}}{32 \text{ lb sulfur / mole}}\right)$$

$$\text{lb } SO_2 \text{ produced / hr} = K\left(\frac{\text{lb fuel}}{\text{hr}}\right)\left(\frac{\text{\% sulfur in fuel} \times 2}{100}\right)$$

$$\%\ SO_2 \text{ by weight} = \frac{\text{lb } SO_2 \text{ / hr} \times 10^2}{\text{lb flue gas / hr}}$$

$$\text{ppm } SO_2 \text{ by weight} = (\%\ SO_2 \text{ by weight}) \times 10^4$$

$$\%\ SO_2 \text{ by volume} = \frac{100\ (\%\ SO_2 \text{ by weight / 64})}{\dfrac{(\%\ SO_2 \text{ by weight})}{64} + \dfrac{100 - (\%\ SO_2 \text{ by weight})}{M}}$$

$$\text{ppm } SO_2 \text{ by volume} = \%\ SO_2 \text{ by volume} \times 10^4$$

where K = 0.95 cyclone furnace firing
0.97 dry bottom PC firing
0.99 oil firing

M = molecular weight of flue gas
30.2 coal firing
29.0 oil firing

O_3:

SO_3 quantity = 1% of SO_2 quantity (coal firing)
= 2% of SO_2 quantity (oil firing)

H-1. Definition of Heat Rates

$$\text{Turbine Cycle Heat Rate} = \frac{\text{Energy Input to Feedwater \& Steam (BTU)}}{\text{Generator Output (kWhr)}}$$

$$\text{Gross Heat Rate} = \frac{\text{Energy from Burned Fuel (BTU)}}{\text{Generator Output (kWhr)}}$$

$$\text{Net Heat Rate} = \frac{\text{Energy from Burned Fuel (BTU)}}{\text{Generator Output} - \text{Station Consumption (kWhr)}}$$

$$\frac{\text{Turbine Cycle Heat Rate}}{\text{Gross Heat Rate}} = \frac{\text{Turbine Cycle Heat Rate}}{\text{Boiler Efficiency}} \left(\frac{\text{(BTU)}}{\text{kWhr}}\right)$$

$$\frac{\text{Gross Heat Rate}}{\text{Net Heat Rate}} = \frac{\text{Gross Heat Rate}}{(1 - \ \text{\% Station Comsumption})} \left(\frac{\text{(BTU)}}{\text{kWhr}}\right)$$

H-2. Heat Losses in Steam Generating Units

(Based on ASME Test Form for Abbreviated Efficiency Test)

$$\text{Dry Refuse per lb of as-fired fuel} = \frac{\text{\% ash in as-fired fuel}}{100 - \ \text{\% combustible in refuse sample}} \left(\frac{\text{lb}}{\text{lb}}\right)$$

Carbon burned per lb of as-fired fuel =

$$\frac{\text{\% wt carbon in fuel sample}}{100} - \frac{\text{dry refuse per lb fuel} \times \text{BTU per lb refuse}}{14{,}500} \left(\frac{\text{lb}}{\text{lb}}\right)$$

100-% combustible in refuse sample

Note: If flue dust and ash pit refuse differ materially in combustible content, they should be estimated separately.

Dry gas per lb of as-fired fuel burned, lb/lb =

$$\frac{11CO_2+8O_2+7(N_2+CO)}{3(CO_2+CO)} \times (lb\ carbon\ burned\ per\ lb\ as-fired\ fuel + 3/8S)$$

CO_2, O_2 and CO are the percent by volume of carbon dioxide, oxygen and carbon monoxide, respectively in the flue gas. N_2 is the percent by volume of nitrogen, by difference, in the flue gas. S is the lb of sulfur per lb of as-fired fuel from the fuel analysis or % sulfur in fuel/100.

1. **Heat loss due to dry gas**

   = lb dry gas per lb as-fired fuel burned × .24 (Tg – Ta)
   where .24 = specific heat of gas
   Tg = temperature of gas leaving unit, ˚F
   Ta = temperature of air entering unit, ˚F

2. **Heat loss due to moisture in fuel**

   = (H_2O/100) × (enthalpy of vapor at 1 psia and Tg – enthalpy of liquid at Ta)
   where: H_2O = % moisture in fuel

3. **Heat loss due to hydrogen in fuel**

   = (9 H_2/100) × (enthalpy of vapor at 1 psia and Tg – enthalpy of liquid at Ta)
   where: H_2 = % hydrogen in fuel
   Tg = temperature of gas leaving unit, ˚F
   Ta = temperature of air entering unit, ˚F

4. **Heat loss due to CO in flue gas**

   = CO/(CO_2 + CO) × 10160 × lb carbon burned per lb as-fired fuel
   where: CO and CO_2 are percent by volume of carbon monoxide and carbon dioxide in flue gas
   10160 = Btu generated burning 1 lb of CO to CO_2

5. **Heat loss due to unburned combustible**

   = Dry refuse (ash pit + fly-ash) per lb as-fired fuel × Btu per lb in refuse (weighted average) Calculations for each of the above five losses will give the Btu per lb for each loss. To determine the percent loss in efficiency, which is the percent of heating value of as-fired fuel:
   (Btu in loss/Btu per lb as-fired fuel) × 100 = % loss

H-3. Heat Loss Due to Unburned Carbon %

% Ash	HHV 8,000	HHV 9,000	HHV 10,000	HHV 11,000	HHV 12,000	HHV 13,000
4%	0.08%	0.07%	0.06%	0.06%	0.05%	0.05%
6%	0.11%	0.10%	0.09%	0.08%	0.08%	0.07%
8%	0.15%	0.14%	0.12%	0.11%	0.10%	0.09%
9%	0.17%	0.15%	0.14%	0.12%	0.11%	0.11%
10%	0.19%	0.17%	0.15%	0.14%	0.13%	0.12%
11%	0.21%	0.19%	0.17%	0.15%	0.14%	0.13%
12%	0.23%	0.20%	0.18%	0.17%	0.15%	0.14%
13%	0.25%	0.22%	0.20%	0.18%	0.17%	0.15%
14%	0.27%	0.24%	0.21%	0.19%	0.18%	0.16%

*Values are determined as % heat loss per 1% L.O.I.

HHV = Heat value of fuel as received Btu/lb

% Ash = Percent ash in as received fuel

6. **Unaccounted for losses %**

These losses include sensible heat in ash, moisture in the air and other minor losses which are not measured.

The design value on almost all boilers is 1.5%. The value normally used in testing is 0.3%.

I-1. Flow Through of an Orifice or Nozzle for Water and Steam

$$\dot{m} = \frac{358.93 \times C \times Y \times d^2 \times Fa \times \sqrt{\rho} \times \sqrt{\Delta P}}{\sqrt{1-\beta^4}}$$

Where:

$\dot{m}$ = Mass flow (lb/hr)

C = Discharge Coefficient

Y = Fluid Expansion Factor

For Water, Y = 1.0

For Steam, Y = 0.995 for β=0.6, P_2/P_1=0.99

For Steam, Y = 0.975 for β=0.6, P_2/P_1=0.96

For Y, see the ASME “Fluid Meters”

d = Diameter of orfice or nozzle (in.)

Fa = Thermal Expansion Factor

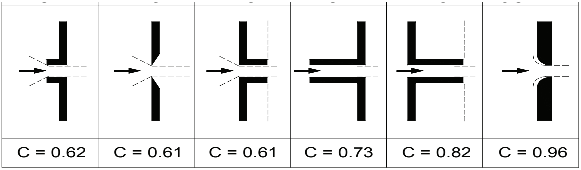
At 200°F (94°C) for 300 SS Material = 1.002

At 600°F (315°C) for 300 SS Material = 1.010

At 1000°F (538°C) for 300 SS Material = 1.019

ρ = Density (lb/ft ^{3})

ΔP = Differential Pressure (“w.c.)



For smooth, well-tapered ASME flow nozzle discharge coefficient is .99 to 1.0.

I-2. Theoretical Air Required for Combustion of Coal or Oil

$$\text{Theoretical Air, lb/10,000 Btu as fired} = 144 \times \frac{8.01C + 23.86(H_2 - \frac{O_2}{8}) + 3S}{\text{Btu/lb}}$$

$$\text{Theoretical Air, lb/lb fuel as fired} = \frac{11.53C + 34.36(H_2 - \frac{O_2}{8}) + 4.32S}{100}$$

Where:

C = Percent by weight of carbon in the fuel, from ultimate analysis

H_2 = Percent by weight of hydrogen in the fuel, from ultimate analysis

O_2 = Percent by weight of oxygen in the fuel, from ultimate analysis

S = Percent by weight of sulfur in the fuel, from ultimate analysis

Btu/lb equals the heating value of the fuel "as fired"

$$\text{Theoretical Air, std. cu. ft. /lb. fuel} = 17.10\left(\frac{C}{12} + \frac{H}{4} + \frac{O}{32} + \frac{S}{32}\right)$$

$$\text{Theoretical Air, lb. / lb. fuel} = 1.38\left(\frac{C}{12} + \frac{H}{4} + \frac{O}{32} + \frac{S}{32}\right)$$

Where:

C = % carbon in the fuel

H = % hydrogen in the fuel

O = % oxygen in the fuel

S = % sulfur in the fuel

I-3. Conversion of NO_X from Ppm to Lbs per Million Btu Input

$$NO_x \text{ (lb/MMBtu) input} = \frac{(\text{ppm } NO_x) \times (0.024457)}{(20.9 - \%O_2)}$$

I-4. Conversion to a Reference O_2 Concentration

NO_X at O_2 reference = (NO_X) × [21 – (O_2, reference)] / [21 – (O_2, measured)]

I-5. NO_X Emissions from Coal

Unit for Original Value	Converted Value*			
	mg NO_2/m^3	ppm NO_X	g NO_2/GJ*	lb NO_2/Mbtu**
mg NO_2/m^3	1	0.49	0.37	8.14 x 10^4
ppm NO_X	2.05	1	0.76	1.67 x 10^3
g NO_2/GJ**	2.70	1.31	1	2.20 x 10^3
lb NO_2/Mbtu***	1230	598	455	1

* @ 6% O_2 0°C and 1.013 x 10^5 Pa. On Dry Gas

** assuming flow gas volume 370m^3/GJ. dry gas (net heat value)

*** assuming flow gas volume 350m^3/GJ. dry gas (gross heat value)

J-1. Parameters Impacting Heat Rate

Parameter	Change	%HR
OPERATOR CONTROLLABLE		
Outlet Gas Temp (12,000 Btu/lb Coal)	10° F	0.25%
Outlet Gas Temp (8,000 Btu/lb Coal)	10° F	0.35%
Outlet Gas O_2	1%	0.29%
Main Steam Temp (Subcritical Unit)	10° F	0.15%
Main Steam Temp (Supercritical Unit)	10° F	0.20%
Hot Reheat Temp	10° F	0.14%
Main Steam Pressure (Constant Control Valve)	10 Psi	0.04%
Superheat Spray (From BFP Discharge)	1% of MSF	0.025%
Superheat Spray (From Final FW)	1% of MSF	0.008%
Reheat Spray	1% of MSF	0.20%
PLANT CONTROLLABLE		
Condenser Pressure	1"HG	Thermal Kit
Station Service	1%	1.0%
Final Feedwater Temp	5° F	0.10%
Unburned Carbon	1%	0.1%
Steam Coils (From Drum)	1% of MSF	0.37%
Steam Coils (From Cold Reheat)	1% of MSF	0.25%

*Note: MSF abbreviated for Main Stream Flow

J-2. Parameters Impacting Heat Rate Continued

Parameter	Change	%HR
TURBINE CYCLE COMPONENTS		
HP Turbine Efficiency (Reheat Unit)	1%	0.18%
HP Turbine Efficiency (Non Reheat Unit)	1%	0.60%
IP Turbine Efficiency	1%	0.17%
LP Turbine Efficiency	1%	0.45%
BFP Efficiency	1%	0.02%
BFPT Efficiency	1%	0.02%
Top HP Heater TTD	5° F	0.10%
Other Heaters TTD	5° F	0.03%
BOILER COMPONENTS		
Coal Moisture (12,000 Btu/lb Coal)	1%	0.10%
Coal Moisture (8,000 Btu/lb Coal)	1%	0.17%
Air Heater Leakage	1%	0.05%
Air Heater Effectiveness	1%	0.15%
FD Fan Inlet Air Temp	10° F	0.05%
Mill Outlet Air Temp	10° F	0.04%

J-3. Heat Rate Impact of Drum Blowdown

Lb/hr	Equal Makeup GPM	Equal Makeup GPD	%HR Load 200 MW	%HR Load 700 MW
5,000	10	14,400	0.15%	0.05%
10,000	20	28,800	0.30%	0.10%
15,000	30	43,200	0.45%	0.15%
20,000	40	57,600	0.60%	0.20%
25,000	50	72,000	0.75%	0.25%

J-4. Heat Rate Impact of Sootblowing or Thermal Drain Leakage

Lb/hr	Equal Makeup GPM	Equal Makeup GPD	%HR Load 200 MW	%HR Load 700 MW
5,000	10	14,400	0.40%	0.10%
10,000	20	28,800	0.80%	0.20%
15,000	30	43,200	1.2%	0.30%
20,000	40	57,600	1.6%	0.40%
25,000	50	72,000	2.00%	0.50%

K-1. Typical Sootblower Steam Consumption

Unit	Lbs/Cycle	Lbs/hr
Wall Blowers	127	5,000
20 ft. Boiler Retracts <2000°F	400	2,500
20 ft. Boiler Retracts @2800°F	1,200	7,000
40 ft. Boiler Retracts <2000°F	2,500	10,000
40 ft. Boiler Retracts @2800°F	6,000	24,000
Size #24 Air Heater Swing Arm	2,300	4,600
Size #24 Air Heater Retracts	1,000	2,000
Size #31 Air Heater Swing Arm	6,400	12,800
Size #31 Air Heater Retracts	3,000	6,000
Waterlances	450	30,000

K-2. Abnormal Feedwater Heater Operation

Top Heater Out of Service	1.2%
Next to Top Heater Out of Service with Top Heater Drain to Condenser	1.8%
Both High Pressure Heaters Out	2.2%
1/2 of High Pressure Heaters Out	1.1%
One LP Heater Out of Service	0.3-0.5%
Next to Top Heater Drain to LP Heater Rather Than DA	0.2%
Top Heater Extraction Line DP +10%	0.2%
Other Heater Extraction Line DP +10%	0.04-0.06%

K-3. Heat Rate Impacts of Cycle Isolation Problems on a Reheat Unit

Leakage Source, Amount, and Destination	Heat Rate Effect
1% (of MS) from Primary Superheat to Waste	0.8%
1% (of MS) from Main Steam to Condenser	1%
1% (of MS) from Cold Reheat to Condenser	0.7%
1% (of MS) from Hot Reheat to Condenser	0.9%
1% (of MS) from IP Exhaust to Condenser	0.6%
1% (of MS) from Final Fw to Condenser	0.18%
10% of Top Heater Extraction to Condenser	0.6%
10% of Next to Top Heater Extraction to Condenser	0.4%
10% of DA/BFPT Extraction to Condenser	0.5%
10% of LP Heater Extraction to Condenser	0-0.01%
100% of Top Heater Shell Drain to Condenser	1%
100% of Next to Top Heater Shell Drain to Condenser	1%
100% of LP Heater Shell Drain to Condenser	0-0.1%
10% FW Bypassing Top Heater	0.12%
10% FW Bypassing Other Heaters	0.03%
1% of BFP Suction to Condenser	0.05%
1% Minimum Flow Valve Leakage	0.01%
20% FW Recirculating to DA @ 60% Load	0.4%

Note: MS abbreviated for Main Steam

K-4. Parameters Impacting MW Load Reheat Unit

Parameter	Unit	MW Change
HP Efficiency	1%	0.28%
IP Efficiency	1%	0.17%
LP Efficiency	1%	0.45%
Throttle Flow	1%	0.94%
Throttle Pressure	1%	1%
Superheat Temp	10° F	0.10%
Reheat Temp	10° F	0.50%
Superheat Spray	1% of MSF	0.08%
Reheat Spray	1% of MSF	0.60%
Condenser Pressure	1”HG	Thermal Kit
Cold Reheat (EXTRACTION)	1%	0.70%
Final FW Temp	5° F	0.40%

Note: MSF abbreviated for Main Steam Flow

L-1. Boiler Performance Rules of Thumb

Sometimes approximate values are useful for quick performance analyses to determine orders of magnitude of temperatures, efficiency effects, capacities and so forth. Some approximate rules of thumb are used by Innovative Combustion Technologies field engineers, until exact calculations can be made. These generally apply to large utility central station power plants for the 2400 psi 1000°F/1000°F single stage of reheat cycle.

- Approximately eleven pounds of air per pound of Eastern Bituminous fuel fired – total air requirement
- 15% to 20% primary air
- 80% to 85% secondary air
- 7 pounds of steam per kilowatt hour
- 1.15 pounds of air per pound steam flow
- 0.7 pounds of coal per kWhr
- 35°F exit gas temperature change – approximately 1% boiler efficiency change (Eastern Bituminous Coal only)
- 1% Flyash LOI change is equal to about 0.1% boiler efficiency change (Eastern Bituminous Coal)

80% Flyash/ 20% Bottom Ash	Dry Bottom Boilers
70% Flyash/ 30% Bottom Ash	Wet Bottom P.C. Boilers
20% Flyash/ 80% Bottom Ash	Wet Bottom Broken Coal Fired Boilers (cyclones)

L-2. Thermal Efficiency of a Boiler

$$\text{Efficiency} = \frac{W_1(H_1 - h_1) + W_2(H_2 - h_2)}{C} \text{ x } 100\%$$

Where:

W_1 = Actual initial evaporation (lb/hr)

W_2 = Actual steam reheated (if any) (lb/hr)

C = Gross heating value of fuel burned (Btu/hr)

H_1 = Enthalpy in initial steam (Btu/lb)

H_2 = Enthalpy in reheat steam (if any) (Btu/lb)

h_1 = Enthalpy of feed water(Btu/lb)

h_2 = Enthalpy in steam entering reheater (if any) (Btu/lb)

To calculate the net, lower heating value from the gross, or higher heating value:

$$\text{LHV} = \text{HHV} - 1040 \; \frac{(M + 9H_2)}{100}$$

Where:

M = Percent moisture in fuel (%)

H_2 = Percent hydrogen in fuel (%)

NOTE:

In the United States the HHV is commonly used in heat balance calculations. In Europe the LHV is most commonly used.

Conversion Factors

To Convert From	To	Multiply By
Area		
Square Feet (ft^2)	Square Centimeters (cm^2)	929.0304
Square Feet (ft^2)	Square Meter (m^2)	0.09290304
Square Feet (ft^2)	Square Inches(in^2)	144
Square Inches(in^2)	Square Centimeters (cm^2)	6.4516
Length		
Feet (ft)	Centimeters (cm)	30.48
Feet (ft)	Meter (m)	0.3048
Feet (ft)	Inches(in)	12
Inches (in)	Millimeters (mm)	25.4
Inches (in)	Centimeters (cm)	2.54
Mass/Force		
Pounds (lb)	Grains (gr)	7000
Pounds (lb)	Grams (g)	453.59237
Grains (gr)	Grams (g)	0.06479891
Kilograms (kg)	Pounds (lb)	2.2046226
Kilogram-force (kgf)	Newton (N)	9.80665
Pound-force (lbf)	Newton (N)	4.44822
Temperature		
Degrees Celsius (°C)	Kelvin (K)	K = °C + 273.15
Degrees Celsius (°C)	Degrees Fahrenheit (°F)	°F = 9/5 (°C + 32)
Degrees Fahrenheit (°F)	Degrees Rankine (°R)	°R = °F + 459.67 = 1.8K
Degrees Fahrenheit (°F)	Degrees Celsius (°C)	°C = 5/9 (°F − 32)
Power, Energy, Heat		
British Thermal Unit per Min (Btu/min)	Steam, Pounds per Hour (lb/hr Steam)	1 x 10^{-3}
Horsepower (hp)	Watts (W)	745.7
Horsepower, boiler (hp)	British Thermal Unit per hour (Btu/hr)	33445.7
Horsepower, boiler (hp)	Kilowatts (kW)	9.8095
Kilowatt-Hours (kWhr)	British Thermal Unit per hour (Btu/hr)	3414.43
British Thermal Unit, mean (Btu)	Kilogram-Calories (kcal)	0.252
British Thermal Unit, mean (Btu)	Watts per Second, Joule (J)	1055.06
Pressure		
Inches of Mercury (In Hg)	Millimeters of Mercury (mm Hg)	25.4
Inches of Mercury (In Hg)	Inches of Water (in H_2O)	13.6
Inches of Mercury (In Hg)	Atmospheres (atm)	0.0334211
Inches of Mercury (In Hg)	Kilopascals (kPa)	3.386388
Atmospheres (atm)	Bars (bar)	1.01325
Atmospheres (atm)	Pounds per Square Inch (psi)	14.695949
Pascals (Pa)	Newton per Square Meter (N/m^2)	1.0
Volume		
Cubic Meters (m^3)	Cubic Feet (ft^3)	35.314667
Cubic Feet (ft^3)	Liters (l)	28.136847
Liters (l)	Cubic Centimeters (ccm)	1000

Constants

Avogadro's Number	6.02×10^{23} atoms/g atom
Gas Constants	82.05 atm cm^3/(g-mole * K)
	1.987 cal/(g-mole * K)
	10.731 ft lb in^2/(lb-mole * °R)
	0.732 ft^3 atm/(lb-mole * °R)
1 g-mole of Ideal Gas	24.05 Liters at US EPA Standard Conditions

US EPA Standard Conditions

Standard Temperature (T_{std})	20°C (68°F)
Standard Pressure (P_{std})	760mm Hg (29.92in Hg)

Gas Concentration Units

Parts-per-million by volume (ppm_v) to milligrams per dry standard cubic meter (mg/dscm)

$$\text{mg / dscm} = \left[\frac{ppm_v \times MW}{22.405 \ \frac{Liters}{g\text{ - }mole}} \right]$$

Correct to x% O_2

$$C_{S\ @\ x\ \%O_2} = C_S \times \left[\frac{20.9 - x\%O_2}{20.9 - \%O_{2\ (dry\ actual)}} \right]$$

Gas Concentration Units		
To Convert From	**To**	**Multiply By**
Parts-per-million (ppm) SO_2	Nanogram/Std Cubic Meter (ng/scm) SO_2	2.66×10^{6}
Parts-per-million (ppm) SO_2	Pounds/Std Cubic Foot (lb/scf) SO_2	1.660×10^{-7}
Parts-per-million (ppm) NO_X	Nanogram/Std Cubic Meter (ng/scm) NO_X	1.912×10^{6}
Parts-per-million (ppm) NO_X	Pounds/Std Cubic Foot (lb/scf) NO_X	1.194×10^{-7}

Average of Square Roots of Δp$_i$

$$\left(\sqrt{\Delta p}\right)_{avg} = \frac{\sum_{i=1}\sqrt{p_i}}{n}$$

Average Δp

$$\Delta p_{avg} = \left[\sqrt{\Delta p_{avg}}\right]^2$$

Absolute Stack Pressure

$$P_s = P_b + \frac{P_g}{13.6}$$

Stack Gas Dry Molecular Weight

$$M_d = 0.44(\%CO_2) + 0.32(\%O_2) + 0.28(\%N_2 + \%CO)$$

Stack Gas Wet Molecular Weight

$$M_s = M_d\,(1 - B_{ws}) + 18.0B_{ws}$$

Stack Gas Velocity

$$v_s = K_p C_p \left(\sqrt{\Delta p}\right)_{avg} \sqrt{\frac{T_{s(avg)}}{P_s M_s}}$$

K_p = *85.48 (English Units)*
= *34.96 (Metric Units)*

Area of Stack (Circular)

$$A_s = \Pi \left(\frac{D_s}{2}\right)^2$$

Area of Stack (Rectangular)

$$A_s = LW$$

Volumetric Flow Rate (acfm)

$$Q_a = 60 v_s A_s$$

Volumetric Flow Rate (scfm)

$$Q_s = K_1 v_s A_s \frac{P_s}{T_s}$$

Volumetric Flow Rate (dscfm)

$$Q_{sd} = K_1(1 - B_{ws}) v_s A_s \frac{P_s}{T_s}$$

Dry Gas Meter Volume

$$V_{m(std)} = K_1 Y \frac{V_m\left(P_{bar} + \frac{\Delta H}{13.6}\right)}{T_m} \text{ or } = V_m Y \left(\frac{T_{std}}{P_{std}}\right) \frac{\left(P_{bar} + \frac{\Delta H}{13.6}\right)}{T_m}$$

K_1 = *17.64 (English Units)*
= *0.3858 (Metric Units)*

Volume of Water Vapor

$$V_{wc(std)} = K_2(V_f - V_i)$$

K_2 = *0.04706 (English Units)*
= *0.001333 (Metric Units)*

Stack Gas Moisture Fraction

$$B_{ws} = \frac{V_{wc(std)}}{V_{m(std)} + V_{wc(std)}}$$

Pollutant Mass Rate

$$\overline{PMR_s} = c_s Q_s$$

Estimated Nozzle Diameter

$$D_{n(est)} = \sqrt{\frac{K_3 Q_m P_m \sqrt{T_s M_s}}{T_m C_p (1 - B_{ws}) \sqrt{P_s \Delta p_{avg}}}}$$

K_3 = *0.03575 (English Units)*
= *0.6071 (Metric Units)*

K-Factor

$$K = \frac{\Delta H}{\Delta P} = K_6 D_n^4 \Delta H_{@} C_p^2 (1 - B_{ws})^2 \frac{M_d T_m P_s}{M_s T_s P_m}$$

K_6 = *846.72 (English Units)*
= *8.009×10^{-5} (Metric Units)*

Meter Orifice Flowrate

$$\Delta H = K \Delta P$$

Average Moisture Content

$$B_{ws} = \frac{V_{wc(std)}}{V_{m(std)} + V_{wc(std)}}$$

Isokinetic Rate Percentage

$$\%I = \frac{K_5 T_s V_{m(std)}}{P_s v_s A_n \theta (1 - B_{ws})}$$

K_5 $= 0.09450$ *(English Units)*

$= 4.320$ *(Metric Units)*

Average Standard Flow Rate of Dry Stack Gas

$$Q_{sd(avg)} = 3600(1 - B_{ws(avg)}) v_{s(avg)} A_s \left(\frac{T_{std}}{T_{s(avg)}}\right)\left(\frac{P_s}{P_{std}}\right)$$

% Excess Air

$$\%EA = \frac{(\%O_2) + 0.5(\%CO)}{0.0264(\%N_2) - (\%O_2) + 0.5(\%CO)}$$

F_0 Factor

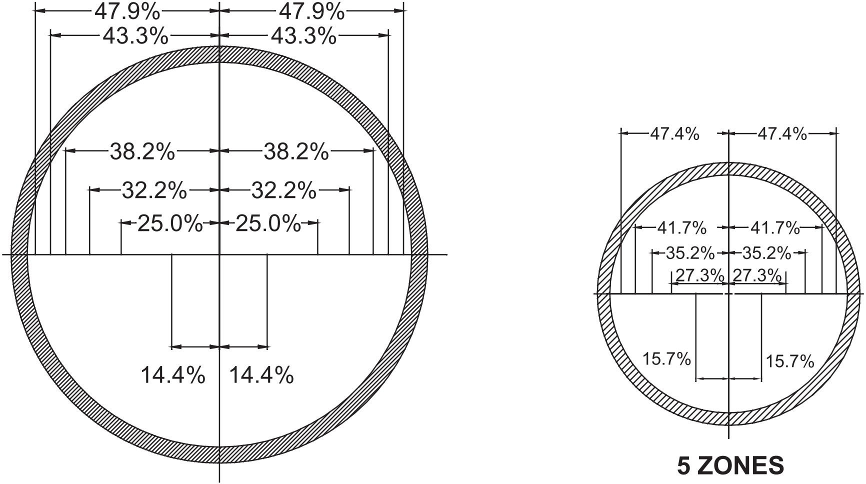
$$F_0 = \frac{20.9 - \%O_2}{\%CO_2}$$

Nomenclature

A_n	Sampling Nozzle Cross-Sectional Area, mm^2 (in^2)
A_s	Stack Cross-Sectional Area, m^2 (ft^2)
B_{ws}	Percent Moisture in Stack Gas, % H_2O
C_p	Pitot Tube Calibration Coefficient
$C_{p(std)}$	Standard Pitot Tube Calibration Coefficient
c_s	Particulate Concentration in Stack Gas, g/dscm gr/dscm (lb/dscf gr/dscf)
D_e	Equivalent Diameter, m (ft)
D_n	Sampling Nozzle Diameter, mm (in)
Δp	Stack Gas Velocity Pressure, mm H_2O (in H_2O)
$(\Delta p^{1/2})_{avg}$	Average of the Squareroots of Velocity Pressure, $(mm\ H_2O)^{1/2}$ $(in\ H_2O)^{1/2}$
%EA	Percent Excess Air, %
F_d	F factor for dry effluent, used with percent O_2, dry basis
F_o	Fuel Factor
$\Delta H_@$	Pressure Drop across Orifice Meter for 21.2 lpm (0.75cfm) at Std Conditions, mm H_2O (in H_2O)
ΔH	Pressure Drop across Orifice Meter, mm H_2O (in H_2O)
%I	Isokinetic Sampling Rate, %
K	Isokinetic Rate Constant
K'	Critical Orifice Calibration Factor
K_p	Pitot Tube Constant
L	Length of Duct Cross-Section at Sampling Site, m (ft)
m	Mass, g (lb)
M_d	Stack Gas Dry Molecular Weight, g/g-mole (lb/lb-mole)
M_s	Stack Gas Wet Molecular Weight, g/g-mole (lb/lb-mole)
pmr	Pollutant Mass Emission Rate, kg/hr (lb/hr)
P_b	Barometric Pressure, mm Hg (in Hg)
P_s	Absolute Stack Pressure, mm Hg (in Hg)
P_{std}	Standard Pressure, 760 mm Hg (29.92 in Hg)
Q_{aw}	Actual Wet Volumetric Flowrate, acmm (acfm)
Q_{sd}	Dry Standard Volumetric Flowrate, dscmm (dscfm)
ρ_w	Density of Water, 0.9982 g/ml
θ	Time (minutes)
T_s	Stack Temperature, °C (°F)
T_{std}	Standard Temperature, 293K (528°R)
T_{amb}	Ambient Temperature, °C (°F)
V_{cr}	Critical Orifice Volume, m^3 (ft^3)
V_m	Dry Gas Meter Volume, m^3 (ft^3)
V_{lc}	Volume or Mass Liquid Collected in Impingers, ml or g
W	Width of Duct Cross-Section at Sampling Site, m (ft)
Y	Dry Gas Meter Calibration Factor

Figure Index

Calculations and Formulae Index



6 ZONES
12" OR LARGER

5 ZONES
10"-11" PIPE

Dimensions are "Percent of Pipe Diameters"
EQUAL AREA TRAVERSE GRID