

## 1. Combustion Considerations - General

Simply stated ... it is the Burner's responsibility to accept the input of at least two dissimilar fluids, mix them, ignite them, oxidize all of the combustible material with the least amount of excess air and the least possible emissions, all over the widest range of firing rates without instability and with a flame envelope that does not impinge on heat transfer surfaces. Reduced electrical energy consumption, low fuel and atomizing media supply pressure requirements and reduced atomizing media consumption are other desirable features. To accomplish all of this not only requires that the Burner's mechanical design be optimum but as well the control and fuel handling systems responsible for the flow control and the conditioning of those inputs.

### Rule #1

Under the exact same conditions it is not possible to achieve a Burner performance level over the full range of firing rates while in the "automatic" mode which exceeds that possible when operated in "manual" at each firing rate.

### Rule #2

A Burner is a system of fixed orifices. Without proper fuel handling and preparation systems, a proper control strategy/system and a means by which to monitor performance, it is not possible to achieve and maintain a level of automation which provides repeatable, efficient and safe operation. Applying a simple control strategy to a Burner based on an argument of simplicity (and lower cost) ignores the responsibility to provide a system which provides repeatable performance and a means by which to assure that through monitoring.

### EXAMPLE

The NOx guarantee on an application is 30 ppmc. The current "indicated" NOx level is 32 ppm with a corresponding excess O2 of 2.5% ("dry"). Correcting the "indicated" value to 3% O2 ("dry") yields ..  $32 \times (17.9/(20.9 - 2.5)) = 31.13$  ppmc. Our published guarantee is that we can operate with between 1.5 to 2.5% excess O2 with less than 100 ppmc CO. You reduce the O2 to 1.5% ("dry"), the "indicated" NOx remains 32 ppm and the CO does not increase above 100 ppmc:

$$32 \times (17.9/(20.9-1.5)) = 29.53 \text{ ppmc}$$

Nothing is this easy but regardless it raises a couple of interesting questions ...

- By the way ... Why was the O2 at 2.5%? You had set the unit up at 1.5% at the same firing rate the other day. ... You are reminded that the air temperature has dropped 50 degrees since the other day and that the control system (provided by others) is without "O2 Trim".? How do you prevent this from happening again?
- By the way ... Why was the O2 at 2.5%? You had set the unit up at 1.5% at the same firing rate the other day. ... You note that the regulated gas pressure at

the inlet to the piping train is now 10 psig while it was 12 psig the other day. You are reminded that there is a single pressure regulator for all three Boilers in the plant and that you had set up your Burner the other day when the other two Boilers were inoperative (the load has now increased and all three units are now online). The control system (provided by others) is without "O<sub>2</sub> Trim" and you have no means of measuring gas flow. How do you prevent this from happening again?

The above example and the follow-up issues are presented to convey that the performance of a Burner is not a "snapshot" taken at the time of commissioning, rather it is an ongoing issue that depends on providing control, fuel handling and monitoring systems that make appropriate adjustments for varying conditions and as well provide a means by which to identify and then correct any deficiencies.

## 2. Pressure and Flow Basic Principles

Most of these have to do with the resistance to a fluid's flow (i.e. pressure drop) imposed by not only the Burner, but by piping, ducting, breeching, etc. and the influence of fluid properties on that resistance. The general equation (developed by Darcy) for calculating pressure drop (DP) across any system element and for any fluid is:

$$DP = K \times p \times (((Q/A)/1096.7)^2) \times CFp \times CFt \times CFe$$

DP = Pressure Drop, inches W.C. (Divide by 27.8 for Pressure Drops in PSI)

K =  $f \times L/Dh$  (See note below)

f = Friction Factor which depends on the Reynolds Number (Re), the Hydraulic Diameter (Dh) and the flow conduit "roughness" (e). "Re" in turn depends on the fluid mass flow rate (W.), its "actual flowing" viscosity (u) and (Dh)

L = Length of pipe, or the equivalent length of an elbow, a piping "tee", etc.

Dh = Hydraulic Diameter ( $4 \times \text{Flow Cross-sectional Area} / \text{Wetted Perimeter}$ ) (Note: The Dh for any item of a round cross-section is equal to its diameter)

p = The fluid's "standard" density at 60° F, atmospheric pressure and at sea level, lbs/SCF

Q = The fluid's flow rate referenced to "standard" conditions, SCFM

A = The cross-sectional flow area, ft<sup>2</sup>

CFp (Pressure Correction Factor) =  $14.7/(Pinlet+14.7)$ ; Where P is in psig

CFt (Temperature Correction Factor) =  $(Tinlet+460)/520$ ; Where T is in deg. F.

CFe (Elevation Correction Factor) – less than 1 for any elevation below sea level

Alternatively the above equation can be re-arranged to solve for flow:

$$Q = 1096.7 \times A \times ((DP/(K \times p \times CFp \times CFt \times CFe))^{1/2})$$

One need not remember these equations or know how to use them. They should remember the following ... for a fixed DP:

- If the site elevation increases, the flow rate in SCFM or lbs/hr. decreases. (Note: this can occur if the Burner is on a Rental Boiler)
- If the inlet temperature of the fluid increases, the flow rate in SCFM or lbs/hr. decreases (Note: seasonal change in ambient air temperature).
- If the inlet pressure of the fluid increases, the flow rate in SCFM or lbs/hr. increases (Note: change in Pressure Regulator setpoint).
- If the “standard” density of the fluid decreases, the flow rate in SCFM or lbs/hr. increases. (Note: this could occur if there was a change in Fuel Oil grade from #6 to #2)
- If the cross-sectional flow area of the item increases, the flow rate in SCFM or lb/hr. increases (Note: this could occur if there was an increase in the number of holes or the hole drill size of the Gas Injectors or Sprayer Plate).
- If the viscosity of the fluid increases, the “Re” decreases and the “f” increases whereupon the flow rate in SCFM or lbs/hr. decreases (Note: a change from #2 to No. 6 Fuel Oil).

Note: The term “K” is one used by Crane (Technical Paper 410 –“Flow of Fluids”) to reflect a given device’s “resistance to flow”. The term “Cv” used by most control valve manufacturers includes an area allowance, while Orifice Plate calculations use the terms “C” (orifice coefficient) and “Y” (expansion factor). Nonetheless, the conditions affecting the pressure drop across all of these devices is accounted for identically.

Note: In the guaranteed operating Excess Oxygen range (1.5-2.5% “dry” O<sub>2</sub> from 50 to 100% firing rate), a change in fuel or combustion air flow by only 5% would produce an approximate 1% Excess O<sub>2</sub> change.

### 3. Atomizing Media Considerations

The primary purpose of the Atomizing Media is to shear the higher viscosity liquid into fine droplets that can then be thoroughly burned in a short duration. Simply put, it is the role of the Atomizing Media to alter the liquid fuel’s characteristics so that they approximate that of a gaseous fuel. The two most common Atomizing Media are compressed air and steam, though any high pressure gas can be used. If applied properly, either can be used just as effectively. Steam, if available, is generally preferred because it is usually already at a high pressure and the operating cost to differentially

produce this steam is lower than that to compress air. The primary considerations applicable to these two Atomizing Media alternatives are as follows:

Similarities ... Moisture: It is well understood that steam must be trapped to remove any condensed moisture. People forget or are simply unaware that there is considerable moisture in atmospheric air, a lot of which is removed with air compressor intercoolers and after coolers. This “Plant Air” which is generally used for Atomizing Media is interestingly unsuitable as “Instrument Air” because it still contains too much moisture. Moisture of any kind adversely affects the shearing process and is very erosive, causing premature wear of all parts in contact with the atomizing media alone or the mixture of it with the liquid fuel. The importance of providing a suitable number of traps and applying ample insulation to piping cannot be understated.

Dissimilarities ... Change of State: The biggest difference between the two fluids is that compressed air does not undergo a change of state while some steam vapor does condense within the Atomizer, either by direct or indirect contact with the lower (relatively) temperature liquid fuel. Note that some of this condensed steam can actually “flash” back into vapor when it exits the Sprayer Plate due to the expansion that occurs as the stream exits a high pressure area and discharges into atmosphere. The benefits of this condensing and flashing on atomization quality is not the subject of this discussion, rather it is the heat exchange process that influences the selection of the correct Atomizer. Recall that we manufacture both the “Internal Mix” and “External Mix” designs. The former applies the shearing at the Distributor and the resulting Atomizing Media/Liquid Fuel mixture then passes through some number of Mixers before exiting the Sprayer Plate. In addition to the heat exchange that takes place between the Oil Tube/Steam Barrel section of the Atomizer, there is the subsequent and more significant heat exchange that results because of the direct contact between the two fluids. With the “External Mix” design, the shearing process takes place within the Sprayer Plate and the amount of direct contact between the two fluids is limited to the short distance of exposure in the Sprayer Plate “exit hole”. For all of these reasons, application of the “Internal Mix” will generally be limited to heavy fuel oil with steam atomization or light oil with air atomization applications, while the “External Mix” would generally be used otherwise. This may not always be the case, as emissions and/or flame shaping issues may dominate as the more important criteria on specific applications.

### 4. Combustion Air Considerations

The largest single input to the fired equipment is the combustion air. Under ideal mixing conditions there is an absolute minimum quantity of combustion air required to incinerate all of the combustible material in any given fuel and any additional amount above this minimum is termed excess air. Usually some excess air is inputted because mix-

ing is not perfect and as well to serve as a “cushion” during firing rate changes. Many Burners operate with excess air levels of 15-25% (2.5 to 4% excess O<sub>2</sub>), while “Low Excess Air” Burners operate with 5-10% excess air (1 to 2% excess O<sub>2</sub>). It is advantageous to operate with as little excess air as possible because operation with lower excess air levels generally results in the formation of less NO<sub>x</sub> and because fired equipment efficiency increases when operated with lower excess air (less heated mass flow exiting the unit). Of course the difficulty in operating with less excess air is the potential that some portion of the fuel will not totally be incinerated, resulting in CO and Hydrocarbon emissions

The lowest excess air with which the Burner is capable of operating (at each firing rate) can be determined during commissioning when operating the Burner in the “manual” mode. If the complete “set-up” is performed within a short period on a given day, one can presume that factors affecting combustion air flow are fairly constant. Over the course of time the following conditions bear paying attention to:

**Elevation** – for a given site this is not an issue. We bring it up again because if the Burner is on a Rental Boiler, a change in location could result in a change in job site elevation. At an elevation of 3000 feet ASL the density of air is about 10% less than it is at sea level. Therefore there will be an approximate 10% increase in “DP” for the same flow, “Q”, in SCFM or lbs/hr. Alternatively for the same “DP” there will be an approximate 5% reduction in SCFM or lbs/hr. Moving a Burner from a lower elevation to a higher one generally results in deriding its capacity unless a means is provided to compensate ... this is one of the reasons why the **XPlus Burner** is equipped with a VSD.

**Temperature** – this is the one condition that is subject to the greatest variation. If the Burner is “set-up” with 50° F. combustion air and due to seasonal changes the air temperature can vary by +/- 50° F. then there is the potential for the combustion air flow to vary +/-5% from the original “set-up” value. Oxygen Trim would provide the needed compensation ... this is one of the reasons why the **XPlus Burner** is equipped with O<sub>2</sub> Trim.

**Draft** – See the following section 5, “Flue Gas Considerations”

## 5. Flue Gas Considerations

Flue Gasses are of course the products of combustion and exit the fired equipment at elevated temperatures. Besides CO<sub>2</sub>, N<sub>2</sub> and excess O<sub>2</sub> and the emissions of particulate, VOCs, Hydrocarbons, NO<sub>x</sub>, SO<sub>x</sub> and CO, flue gases contain considerable moisture which at the elevated temperatures are in the form of vapor. Emissions will be discussed in a later section, while in this section, we will address Draft, FGR and Moisture.

**Draft:** the Furnace of fired equipment is either operated at a positive pressure or a negative pressure usually termed “draft”. Regardless, flue gasses are ultimately discharged from a stack. The height of the stack is important, because the taller it is, the greater the developed “natural draft”. If multiple pieces of fired equipment are breeched to a single common stack, the natural draft will be impacted by the number of units in operation and their individual firing rates. In some cases, even if there is a tall stack, it is necessary to provide an Induced Draft (ID) Fan to overcome resistances imposed downstream of the fired equipment and to assure that a negative Furnace pressure is maintained regardless of conditions.

The equation for calculating “natural draft” is as follows:

$$\text{Stack Draft} = 7.57 \times L \times ((1/T_a) - (1/T_g)) \times B/30$$

Where: L = Stack Height, feet  
 Ta = Ambient Temperature, deg. Rankine  
 Tg = Flue Gas Temperature, deg. Rankine  
 B = Barometric Pressure, inches Hg

Even on pressurized firing applications, it is possible to have a negative draft in the Furnace at reduced firing rates, when the elevated temperature necessary to produce a natural draft exists while the pressure drop experienced by the flue gas as they pass through the fired equipment is negligible.

There are two potentially serious problems attributable to the existence of draft: if it is not repeatable (i.e. it is not controlled) and/or it results in uncontrolled air infiltration into the fired equipment, it then leads to misleading information regarding the presumed combustion air flow through the Burner(s). The latter problem is referred to as “Tramp Air” and this is discussed in **section 8.2 “Common Application-Specific Problems”**. As to the lack of draft repeatability, we offer the following:

- As should be apparent from the above equation, “natural draft” is dependent on the stack height and the temperature of the flue gases and the environment. For 500° F flue gases, the “natural draft” is 50% higher on a 20° F day than it is on a 100° F day. Though this unto itself may only represent itself in a “few tenths of an inch W.C.”, consider that on the same cold day that the draft is higher, more combustion air is capable of passing through the system (See **section 4 “Combustion Air Considerations”**). The combination may or may not warrant the use of draft control (unless “Tramp air “ is an overruling issue) but the addition of O<sub>2</sub> trim would be justified. This is one of the reasons why the **XPlus Burner** is provided with a combustion control strategy incorporating O<sub>2</sub> Trim.
- Anytime more than one piece of fired equipment is connected to one stack, draft controls should be provided for each unit. This because the “net natural draft” depends not only on the conditions described

above but also on the resistance imposed by the stack on the flow of flue gases through it. Therefore the number of units in operation and their combined firing rate influences the “net natural draft”. ... draft controls are a standard option available with the **XPlus Burner**.

- Draft control should be provided anytime the expected “natural draft” is greater than 2.5% of the “Burner Draft Loss” (i.e. if the “BDL” is 10" W.C. then draft control should be included if the “natural draft” will be greater than or equal to 0.25" W.C.). This because the influence of “natural draft” (which is essentially constant throughout the firing rate range) has a pronounced affect on air flow at firing rates less than 50%.
- Draft control should be provided whenever an “Induced FGR” NOx reduction strategy is provided. The FGR take-off should be upstream of the draft control damper to minimize “tramp air” infiltration.
- Flue gas excess O<sub>2</sub> measurements should also be taken upstream of the draft control damper to minimize “tramp air” bias of the sample.

**FGR (Flue Gas Recirculation):** FGR is effective in reducing NOx emissions despite its elevated temperature, because the additional mass flow inputted to the combustion zone reduces the flame temperature and because it is Oxygen deficient. If FGR is withdrawn from a location which is at a negative draft, it is possible, depending on the tightness of the setting, that “tramp air” has infiltrated into the flue gas. FGR should always be withdrawn from the area that has the lowest potential for “tramp air” infiltration and where the flue gases are at their lowest temperature.

**Moisture:** the amount of moisture in the products of combustion (resulting from the burning of Hydrogen) is considerable (about 10% by volume when burning Fuel Oils and approaching 20% by volume when burning Natural Gas). This moisture, if allowed to collect can result in misleading indications of draft, beginning with those specific to the measurement of Furnace Pressure. Refer to **section 8.2 Common Application-Specific Problems** for further information.

## 6. Gas Fuel Firing Considerations

For a fuel such as Natural gas, one’s contract usually stipulates a very narrow range of Higher Heating Value (HHV in BTU/SCF or BTU/lb) and Specific Gravity (SG). In the case of chemical process Off-Gases, these conditions are likewise fairly constant when the process is being operated normally, but under start-up, shutdown or operational upsets these could change dramatically. A term often times used to compare one gas to another is called the Wobbe Index:

**Wobbe Index = Gas HHV/((Gas SG)<sup>1/2</sup>)**  
Where the HHV is in units of BTU/SCF

The reason for creating this index is that it combines conditions that impact on the gas’ flow rate and its density which in turn affects the pressure drop. We don’t expect to encounter Gas Heating Value and Specific Gravity variations too often but one should be aware of it

**Elevation:** Refer to section 4 “Combustion Air Considerations.” At a given site this is not an issue.

**Temperature:** Like Combustion Air, variations in temperature are very possible though generally not to the same extent.

**Pressure:** There is no reason for pressure variations at the inlet of a Burner’s piping train, unless the fuel is a by-product of some process. Regardless, every Burner piping train should be equipped with a pressure or differential pressure regulator at its inlet. Referencing the Darcy equation given in section 2, an uncontrolled increase in inlet pressure will result in an increase in flow and vice versa. Note that this affect applies to every component in the piping train, so application of a flow meter does not by itself compensate for pressure fluctuations unless the meter is a Thermal Mass type or the reading of an alternative meter is pressure compensated ... this is why the standard XPlus Combustion System includes a differential pressure regulator and a Thermal Mass flow meter.

## 7. Fuel Oil Firing Considerations

Liquids are incompressible fluids, whereupon their density is not influenced by pressure variations. Though a liquid’s density is affected by temperature, not to the same extent as that of gasses (water’s density reduces by about 20% for a temperature change of from 100° to 500° F while any gas will undergo a 40% reduction in density). There are simply significantly more variables to be concerned about when burning liquid fuels. These primarily have to deal with its composition as that influences emissions and other physical characteristics, which impact on storage, pumping, preparation and atomization considerations. Some of the more important fuel oil characteristics are:

### Viscosity

Viscosity is a measure of a fluid’s resistance to flow. It is probably one of the most important properties of the fuel to be fired since it relates to its ability to flow through the lines and be properly atomized at the burner nozzle.

A *high viscosity* fuel like No. 6 oil will thicken considerably at normal room temperatures and requires constant heating and circulation in order to flow and be atomized properly. A low viscosity fuel like No. 2 oil will flow and atomize easily at room temperature.

In the combustion industry, viscosity is generally expressed in SSU or Saybolt Seconds Universal. This is determined in a lab and is the length of time in seconds required for the oil, heated to a specified temperature, to flow through a standard orifice. To assure good fuel oil combustion, the

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maximum value is generally between 100 – 200 SSU for most applications.

Temperature vs. viscosity information is critical in determining the required oil temperature at the burner to achieve the correct SSU for atomization. This data can be obtained from standard viscosity tables. However, some fuels, particularly blends may require that an analysis be provided by the supplier. Regardless, it is always sensible for the user to draw a sample monthly and have it tested by an independent lab.

Problems with fuel viscosity control can lead to burner performance problems. High viscosity can decrease the ability of the atomizer to properly atomize the fuel and result in incomplete combustion, high CO, smoking, and sooty deposits. Viscosity that is below the recommended levels can cause flashing at the sprayer tip and erratic burning. The viscosity must be carefully controlled because of its potential effect on stack opacity, NOx, CO and particulate emissions.

**Pour Point** - The fuel oil pour point is the lowest temperature at which fuel can be stored and still remain fluid or be pumped.

**Cloud Point** – Normally determined for No. 2 oil, is the temperature at which the wax crystals (paraffin) suspended in the fuel first begin to appear and drop out as a slight haze in the sample.

**Flash Point** – The flash point of the fuel oil is the lowest temperature at which a flash flame can be produced. It is an indication of the maximum temperature at which the fuel can be safely stored or handled without causing a serious fire hazard. Oil should not be preheated to a temperature greater than its Flash Point.

**Sulfur Content** – Fuel oil loads containing 1% sulfur or more can be troublesome in terms of corrosion to the fired equipment. During the combustion process, free sulfur will combine with Oxygen to form sulfur dioxide that, in the presence of water molecules, will combine to form sulfurous acid. Although relatively weak, it can over time cause severe corrosion to exposed parts and components. Sulfur dioxide or SO<sub>2</sub> is also considered a major atmospheric pollutant and contributes to smog and acid rain.

**Nitrogen Content** – Fuel oils with high nitrogen content can contribute significantly to the formation of nitrogen oxides or NOx during the combustion process. Nitrogen atoms located in bonds within the fuel molecule are released into the total nitrogen pool and oxidized leading to an increase in NOx levels. This is commonly referred to as fuel NOx and can greatly affect burner emission performance. 0.2 – 2.0% N in fuel can potentially yield 60-2100 ppm NO.

**Summary** – It is important that operators understand the different fuel oil characteristics and how they relate to burner and fired equipment performance. It is especially critical that these factors be taken into consideration anytime a change in the type or grade of fuel is made.

**Caution!**  
**You should contact Preferred Utilities directly before attempting to fire a fuel oil different from that which was fired during initial commissioning. A planned change in suppliers should include receiving confirmation of the new supply's equivalence to the previous fuel supplier. Preferred Utilities should also be notified of this proposed change in suppliers.**

Refer to the following Summary of Fuel Problems excerpted from "The Fuel Oil Manual for Boiler Operation"; Boiler Efficiency Institute, Auburn, AL.

| PROBLEM                      | CAUSE   |
|------------------------------|---|
| Atomization Poor .....       | Oil viscosity too high; improper preheat temperature; atomizing media or oil pressure too low                 |
| Boiler Corrosion.....        | Ash contains corrosive elements; oil sulfur and/or salt content is too high; soot has absorbed sulfuric acid  |
| Burner Erosion.....          | High oil sediment or salt content; velocities in eroded areas (liquid or flue gas-side ) too high             |
| Burner Tip Blocked .....     | High oil sludge or lint content; No strainer or strainer mesh not fine enough; Carbonization of Sprayer Plate |
| Carbon Dioxide Low .....     | Too much excess air; poor air and/or fuel cross-sectional distribution  |
| Carbon on Furnace Walls..... | Flame impingement; oil too viscous or too light; atomizing media/oil injection velocity too high              |
| Carbon in Preheater .....    | Too high preheating temperature; oil contains sludge and/or asphaltic compounds                               |

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| PROBLEM                                | CAUSE   |
|--|---|
| Carbonization of Sprayer Plate.....    | Carbon residue in oils; high viscosity oil, poor atomization; insufficient, excessive or varying pre heat temperature; inadequate guidepipe purge air   |
| Discoloration of Ceramics.....         | High sulfur, sediment, or iron in the oil.  |
| Sprayer Plate Dripping Oil.....        | Oil viscosity too high; incorrect pre heat temperature, partially plugged Sprayer Plate; Sprayer Plate Assembly gaskets missing or damaged  |
| Flame Pulses.....                      | Water, sediment or sludge in oil; oil viscosity too high; non uniform combustion air or oil flow; air infiltration into oil; atomizing media flow irregular or too high; Atomizer internal leak of atomizing media into oil |
| Flame Leaves Sprayer Plate.....        | Too much atomization, oil too thin  |
| Flashback.....                         | Flash point is too low resulting in pre-ignition; water and sludge in oil; fluctuation of atomizing media flow; oil pressure too high   |
| Foaming of Oil.....                    | Water or extremely light material in oil  |
| Heat Loss (poor heat transfer).....    | Sediment and/or water in oil; deficient or excessive combustion air flow; poor combustion; oil temperature too high   |
| Plugged Lines.....                     | Sludge in oil; congealed oil; wax in oil; high viscosity oil; foreign materials in oil  |
| Odor is Bad.....                       | Preheat temperature too high; high oil sulfur content; contamination by other foreign material  |
| Oil Consumption is Excessive.....      | Oil too light, oil of low heat value, excessive combustion air; holes in Sprayer Plate too large (eroded), water in fuel oil  |
| Unable to Pump Oil.....                | Oil too cold or too high in viscosity; restricted or blocked passages; strainers plugged  |
| Smoke.....                             | Not enough or too much combustion air; poor atomization; oil viscosity too high; flame impingement, excessive furnace draft   |
| Soot Excessive.....                    | High ash content in oil; poor combustion; heavy compounds in oil  |
| Spitting, Sputtering Or Sparkling..... | Water or sediment in oil; oil viscosity too high; high atomizing media flow; leakage of air into oil; Atomizer internal leak of atomizing media into oil; wet atomizing media   |
| Stack Temperature Too High.....        | Boiler tubes need cleaning; damaged baffles; too much draft; overfiring of unit   |
| Ignition Difficulty.....               | No oil; sludge and/or water in lines; viscosity of oil too high; too much atomizing media flow; preheat temperature too high, too much combustion air   |
| Strainer Screens Blocked.....          | Sludge; wax or lint in the oil; oil viscosity too high; oil temperature too cold; heavy precipitated compounds in oil; tank scale or rust.  |
| Suction Loss.....                      | Oil too heavy and/or cold; leak in oil suction line, slippage of oil pump; pump not primed; oil too hot.  |
| Water.....                             | Water in oil as delivered; condensation from natural sources (atmospheric humidity) and/or from high temperature heating; leaking heating coils; leaking tank or accesses   |

## 8. Overview - Application Troubleshooting

The following is a brief discussion of a number of possible problems that can be encountered on various applications. This is a general listing, so obviously some of these will not be applicable to this specific project. Most will apply to retrofit applications where our Combustion System is being installed on existing fired equipment and/or existing equipment or systems are being reused. Given the retrofit issue the following must be considered:

- Realistically, the retrofit would not be made unless the latest technology was either desired or required. For this reason, operating issues that may not have been significant prior to the change will be afterwards.
- All modern burners must meet strict emissions requirements as well as provide optimum excess air and turndown performance. Most servicemen carry portable analyzers that allow spot checking of emissions levels. Twenty to twenty-five years ago many of today's requirements or the means by which to monitor them did not exist.
- The above being so, there will be conditions uncovered now which were either not evident or simply non-issues prior to the retrofit.
- Simply put, when problems are encountered after the retrofit, which were never evident beforehand, it will be logical to conclude that the burner is at fault because it is the only thing that has changed. However, bear in mind for all the reasons stated above, not only has the burner changed, but performance expectations, operating issues and the means by which to monitor them have all changed as well.

### 8.1 Operational Rules of Thumb

Natural Gas and Fuel Oils – True excess air ( $O_2$ ) levels in the flame zone that are less than the design level tend to lower  $NO_x$ , increase CO, increase flame length and cross-section and increase opacity (black).

Fuel Oils – Deficient atomizing media flow or higher than design oil viscosities (low oil temperature) tend to lower  $NO_x$ , increase CO, increase flame length and cross-section, increase the visible level of droplets or “fireflies” or “sparklers”, increase opacity and increase liquid splatter on furnace surfaces.

Natural Gas and Fuel Oils – True excess air ( $O_2$ ) levels in the flame zone that are significantly high (greater than 10-11%  $O_2$ ) tend to increase CO, increase opacity (brownish or white) and potentially create instability due to flame blow off.

### 8.2 Common Application-Specific Problems

- A. “Tramp Air”
- B. “Feed the Grate, Starve the Burner”
- C. “Short-circuiting”
- D. Regenerative Air Heater Combustion Air Bypassing
- E. Location of  $O_2$  Sensor

- F. Oversized FD and/or ID Fans
- G. Moisture in Draft Measurements
- H. Air Infiltration into Fuel Oil Piping on Below Grade Storage Applications
- I. Water in the Fuel Oil
- J. Heating or Cooling of Fuel Oil in Atomizers
- K. Heavy Oil Viscosity Increases at Reduced Firing Rates
- L. Wet Atomizing Steam or Plant Air
- M. Single Pressure Regulator but Multiple Users

A. Tramp Air – Tramp Air can be defined as any air that enters the fired equipment unintentionally at a location other than the Burner. Tramp Air can be either a known input i.e. observation port cooling and purging air; soot blower purging air; cooling air to “out-of-service” atomizers; “over-fire” air for grates; “staging air” through “out-of-services” burners; cooling air for “out-of-service” grates, etc or the input can be unaccounted for. Unaccounted for “tramp air” is most common on applications where the furnace is operated at a negative pressure. There is of course the negative heat transfer aspect of an undesirable level of cool air being drawn through the fired equipment. But in addition, there can be the more serious affect resulting from the operation of a Burner at an excess air level based on an  $O_2$  measurement which is gathered downstream of and whose reading is then biased by the “tramp air” infiltration. The problems that will arise are defined in the “Operational Rules of Thumb” associated with less than design levels of excess air. The corrective actions are as follows:

1. Check the location of the  $O_2$  Sensor. See “Location of  $O_2$  Sensor” paragraph in this section. Make the necessary arrangements to relocate the Sensor if its position is less than optimal (Note: this may not be possible without a shutdown).
2. Place the Burner in the “Manual” control mode. Attach a manometer to the Burner’s high air pressure and furnace pressure connections and measure the “BDL” (Burner Draft Loss). Compare this value to that in this O&M Manual for the same Burner Firing Rate.
3. Increase the combustion air flow to the Burner until the “BDL” equals that listed in this Manual for the firing rate. CO, opacity, flame appearance, etc. should all be directionally improved. Note the new operating  $O_2$  level indicated by the Sensor.
4. Slowly change the Furnace Pressure Setpoint on the Furnace Pressure Controller to a value that brings the Furnace Pressure to a slightly positive condition (0.00 to +0.01” W.C.). CAUTION: FLUE GAS INFILTRATION INTO THE

OPERATING AREA CAN BE HARMFUL TO PERSONNEL. Note the reduction in operating  $O_2$  as indicated by the Sensor. This difference in excess  $O_2$  represents the amount of “Tramp Air” infiltration. Return the Furnace Pressure Setpoint to its normal operating level.

5. Note and/or correct all unnecessary “Tramp Air” infiltration points. Those that cannot be corrected while the unit is operating should be documented for correction during the next scheduled outage.
  6. Make the necessary control configuration changes and explain to all operating personnel the new Excess Oxygen, Air Flow to Burner and/or Furnace Pressure operating parameters.
  7. Correct any remaining “Tramp Air” infiltration points during the next fired equipment outage.
- B. Feed the Grate, Starve the Burner – On grate overfiring applications it is common for the combustion air supply to the over-fire burners to be from the same FD Fan as that supplying combustion air to the grate. Under these circumstances, since the grate fuel (wood, coal, bagasse etc.) is the primary fuel, it is common for the majority of the air to be directed to the grate while the over-fire burner(s) are “starved” for air. In effect, the problem is exactly the same as that encountered with an excess of “Tramp Air” ... high CO, opacity, larger/longer fires ... and once again a composite flue gas excess  $O_2$  reading can be deceiving. Because two fuels are being fired simultaneously it is not possible to offer a step by step procedure as was offered for the “Tramp Air” problem. In this case one should again check the “BDL” of each individual Burner, compare it to that in this Manual for the actual Burner firing rate and then adjust overfire Burner and grate combustion air flow control points until both the overfire Burner’s and grate’s performance is optimal. Since grate firing furnaces are typically operated at negative draft conditions “Tramp Air” should be considered in any “tuning” efforts.
- C. Short-circuiting – Short-circuiting is defined as the premature exiting of combustion products from the fired equipment’s furnace to its convection section or exit. Since combustion requires time (as well as temperature and turbulence) to be completed, this “short-circuiting” of combustion products is characterized by high levels of CO (greater than 500 ppm) and/or hydrocarbons at operating  $O_2$  levels which should produce less than 100 ppm. This problem is not a progressive one, rather will occur immediately upon initial Burner start-up. “Short-circuiting” results because of leak paths through the Furnace sidewall separating the Furnace and

the Convection Section. Sidewall constructions of either the “Tangent Tube” or “Studded Tube” type are notorious for “short-circuiting”. On the other hand “short-circuiting” is unlikely when Furnace sidewall construction is either of the “Welded Tangent Tube” or “Membrane Wall” type. Regardless, combustion products must travel the entire furnace length to assure complete oxidation of the combustible material and any leak path, no matter how small, should be scrutinized. If the leak is fairly easy to correct ... such as replacing a refractory plug that has fallen out of a tube inspection port ... then proceed with the change. On the other hand if gaps between tubes need to be filled, the Boiler Manufacturer must be contacted for recommendations. Burner changes are not warranted unless the high CO is the result of “Flame Impingement” (reference that paragraph in this section). Operating at higher excess air levels (where the preceding burner likely operated) is a short-term fix to minimize the exiting CO level. However, this will adversely impact on the ability to meet the performance requirements.

- D. Regenerative Air Heater Combustion Air Bypassing – A Regenerative Air Heater consists of a rotor containing heat transfer “baskets”. This rotor rotates from the combustion air side of the Air Heater to the flue gas side. While in the flue gas area, the “baskets” heat and then this heat is subsequently transferred to the combustion air when it has rotated to that side of the Air Heater. Metal seals (when new) reduce the amount of air leakage to the flue gas side to about 5% of the maximum design combustion air flow. After the seals wear, this leakage rate will increase. Because of this air leakage, one should never sample the  $O_2$  level or locate a continuous  $O_2$  Sensor downstream of a Regenerative Air Heater. If an alternate location upstream of the Air Heater is not available for continuous online sensing, one must at a minimum perform periodic spot checks of the  $O_2$  level on the upstream side (using a portable analyzer) to confirm the level of air leakage and update the operating  $O_2$  parameters based on the downstream sensor.
- E. Location of the  $O_2$  Sensor – Referencing our discussions of “Tramp Air” and “Air Heater Air Bypassing,” it should be apparent that the location of the  $O_2$  Sensor with respect to any intentional or unintentional air infiltration points is critical for establishing the Burner’s true performance. The normal operating excess  $O_2$  levels of the W. N. Best “XPlus” Combustion System from 30 to 100% of capacity is from 1 to 3%. This excess  $O_2$  difference represents itself in an excess combustion air difference of about 10% (recall “as new” Regenerative Air Heater air bypassing is about 5%). For these reasons  $O_2$  Sensors should be located as follows:

1. Locate O<sub>2</sub> Sensors upstream of Regenerative Air Heaters.
  2. Locate O<sub>2</sub> Sensors upstream of any purging or cooling air sources (ie. soot blowers, observation ports).
  3. The O<sub>2</sub> Sensor should protrude into the flue to about 50% of its width. It should also be centered relative to the flue's height.
  4. Ideally, the O<sub>2</sub> Sensor should be installed in a long straight section of the flue. If the Sensor must be installed downstream of an elbow, remember that the flue gas will tend to "hug" the flue face on the "long side of the elbow".
  5. If at all possible establish an O<sub>2</sub> cross-section of the flue using a portable analyzer before installing the permanent Sensor.
- F. Oversized FD and ID Fans – Many burner retrofit applications involve replacing burners whose design excess air levels are considerably higher than that of the W. N. Best "XPlus" Combustion System or replacing solid fuel firing equipment which most assuredly operated with considerably higher excess air. In addition, at the time the original combustion equipment was installed, it is quite possible that the facility did not require this equipment to have high turndown capabilities. The combination of high air delivery capabilities and a lack of a prior need for high turndown will most often result in the existing FD and ID Fans being considerably oversized for the new retrofit burner. This "oversizing" can have a considerable adverse influence on combustion air flow control, particularly at reduced firing rates. The possible corrective measures are as follows:
- a) "Short-stroke" the inlet and/or discharge damper(s) travel (via linkage adjustments) to limit the amount of damper opening at the higher firing rates. Note: this will only improve high firing rate air flow control.
  - b) Add some form of restriction (such as perforated sheet) at the discharge of the fan(s). The addition of this restriction will likely eliminate the need for "short-stroking". Note: this will only improve high firing rate air flow control.
  - c) Add "closure" plates (i.e. strips of metal) to open areas of the fan damper or vanes when they are in the closed position. This will minimize air leakage at lower firing rates. Note: this will only improve low firing rate air flow control.
  - d) A combination of either "a" and "c" or "b" and "c". Note: this will improve both low and high firing rate air flow control.
  - e) Depending on the level of fan derating, replace the existing motor with a lower speed model. This is the most practical alternative but also the most time consuming. Note: this will improve both low and high firing rate air flow control and electrical energy consumption.
  - f) Install a Variable Speed Drive (VSD). This is the most desirable alternative and will most often prove to be the most expeditious one unless the motor has to be upgraded for application to the VSD. Note: this will improve both low and high firing rate air flow control and electrical energy consumption.
- G. Moisture in Draft Measurements – Combustion products contain considerable moisture (and humid air can as well). When these gasses cool, the moisture condenses. Since the vast majority of combustion air, flue gas pressure and differential pressure measurements will be in "inches water column," if the condensed moisture is allowed to collect about the gauge or transmitter diaphragm, the measurement will be faulty. This can have a significant effect on the control of combustion air to the Burner and/or the control of furnace draft. Ideally all sensing tubing should slope downwards from the transmitter connection to the duct, flue, burner or fired equipment pressure connection to promote drainage back towards the process connection. Regardless, in close proximity to the transmitter, the tubing from the transmitter connection should run vertically downward with a "tee" connection on the side for connection to the process and a continuation of the vertical run for at least 6 inches. This will assure that there is a vertical leg for collecting any moisture. This leg should be equipped with a valving arrangement to allow draining the moisture, without disrupting control, while the fired equipment is online.
- H. Air Infiltration into Fuel Oil Piping on Below Grade Storage Applications – When the Oil Storage Tank (or simply the oil level) is below the centerline of the Fuel Oil Pumps, the suction pipe will be at a negative pressure. Any leak in that suction piping will reflect itself as air infiltration into the pipe (i.e. the leak is not visible). Evidence of this problem will be represented by the pump sounding as if it is pumping gravel while both the pump suction and discharge pressure gauge needles will exhibit considerable pressure or vacuum fluctuations. Burner performance will be noticeably impacted because there will be actual fuel oil supply irregularities to it. Depending on the level of air infiltration the fire may have a visible pulse and there will be excess Oxygen fluctuations as well. The only cure for this situation is to locate and repair the leak.

- I. Water in the Fuel Oil – There have been known situations in which fuel oil storage facilities have become intentional receptacles for contaminated water (or other products). Besides these situations, it is not uncommon for leaks to develop on in-tank heating coils over time, resulting in the leakage of steam condensate or hot water into the oil. This water absorbs heat from the combustion process and converts to steam and that heat is never recovered (on non-condensing applications) thereby adversely affecting the fired equipment's efficiency. The "water in the oil" problem may reflect itself in a visual increase in sparklers or fireflies (like high viscosity or poor atomization) but will definitely be evidenced by an increase in oil flow input for the same heat output, excess air level and flue gas outlet temperature. The problem can be identified by drawing a sample of oil from the supply line to the burner(s) and having a local lab check that sample for water content. For No. 5 or No. 6 Fuel Oils, this percentage should be 1-2% or less, while for the other grades this percentage should be no greater than 0.5%. For situations involving intentionally contaminated oil, the problem will resolve itself with close monitoring and time for the contaminated oil to be burned. In-tank heating coil leakage can be established by disconnecting the coils from the steam/condensate or hot water sources and checking to see if oil appears on the steam or hot water side of the coil (Note: the higher the oil level the quicker the leak will appear. Be sure to have a means of isolation to prevent spillage).
- J. Heating or Cooling of Fuel Oil in Atomizers – These conditions have been accounted for in the design of the Preferred **XPlus Burner** Atomizer. They are brought to your attention here, because our design allowances do have limits and operation in excess of these limits will cause the indicated problems. Heavy Oil requires heating to lower its viscosity to a level desirable for burning. In most cases heavy oil is atomized with steam. Since the Preferred atomizer is a "tube within a tube" design, it works quite well as a heat exchanger, allowing one to run lower oil temperatures to the atomizer than they might if this supplemental heat exchange benefit did not exist. If however during start-up, an atomizing steam source did not exist, and one elected to try using compressed air instead, the atomizer's design would promote cooling of the oil. This would be reflected by a significant increase in sparklers and liquid splatter on heating surfaces (just as would be the case with too low an oil temperature). The only way to compensate for this condition is to raise the temperature of the oil entering the atomizer. Conversely, light oil (#2) requires no heating for viscosity control. We have tested the Preferred **XPlus Burner's** operation with
- #2 Fuel Oil heated to 150° F (with compressed air atomization) and know that overall performance is not adversely affected. However, if atomizing steam is used and oil temperatures climb to levels above this point, overheating can occur within the atomizer and unstable pulses can appear in the combustion zone.
- K. Heavy Oil Viscosity Increases at Reduced Firing Rates – Heavy Fuel Oil systems with a single common pumping and heating set which is located some distance from the combustion equipment are prone to this problem. Piping systems which are not designed with a return loop or a pressure regulator at the connection point to the return line aggravate the problem. Piping with a given amount of insulation transfers heat to the space about it at a fixed rate depending on the fluid's temperature (and that of the space), but essentially independent of the fluid's velocity. Therefore the same amount of heat is given up to the surroundings whether oil is flowing through the pipe at a rate corresponding to the Burner's maximum or its minimum firing rate. However, because the amount of heat transferred is constant, the affect on the Fuel Oil's temperature is significantly different. On fuel oil systems of the sort described, it is not uncommon for the oil temperature at the burner to be 20 to 40 degrees lower at minimum firing rate (10-15% of maximum rate) relative to that at maximum. All of the aforementioned problems attributable to unacceptably high oil burning viscosities will result. Changing the piping system, installation of a back pressure regulator, relocation of the pump and heater set temperature sensing element or installation of a local "trim" heater are the corrective alternatives.
- L. Wet Atomizing Steam or Plant Air – Moisture in either the steam or compressed air atomizing media will be evidenced by sparklers. The more significant problem is that liquid carried by any gas stream is very erosive and can result in "water hammer." Both the atomizer and the atomizing media piping components will undergo premature failure if subjected to these conditions. Orifices on the Atomizer Sprayer Plate will "oval" due to erosion and obviously oil burning performance will suffer. Well insulated atomizing media piping should connect to the top of well trapped main headers and then run vertically downward to a mudleg complete with drain and trap assembly. The connection to the burner piping train should be off the side of the vertical run approximately 12" from the bottom of the mudleg
- M. Single Pressure Regulator but Multiple Users – A properly designed fuel or atomizing media main piping system should assure that the pressure and

temperature (see “Heavy Oil Viscosity Increases at Reduced Firing Rates” above) supplied at the inlet to the burner piping trains are a constant regardless of the firing rate combinations of all of the fired equipment in the facility. Unfortunately due to plant expansions or other reasons, it is common to encounter pressure “drips” in the fuel pressures at the burner piping train inlets which varies depending on the operating states of all the fired equipment. This results from the existence of only a single pressure regulator which is responsible for controlling the entire header pressure. Pressure variations at the burner piping train inlet is an unacceptable condition and is particularly unsafe when this occurs with gaseous fuels. This because the actual flow rate and/or the measured flow rate (via flowmeters) are both affected by pressure (due to compressibility), so variations can lead to both real and measured errors which can be both inconsistent and dangerous. The solution is to install a pressure regulator in the local piping for combustion system served.

The most commonly referenced emissions on Boiler or HTHW Generator applications are NO<sub>x</sub>, SO<sub>x</sub>, THC, CO, Particulates and VOC. Most are familiar with the first five emissions. The definition of “VOC” or “Volatile Organic Compound” is ... “a group of chemicals that react in the atmosphere with nitrogen oxides in the presence of heat and sunlight to form ozone; does not include methane and other compounds determined by EPA to have negligible photochemical reactivity. Examples of VOCs include fumes from gasoline, solvents and oil-based paints.” Since there is effectively no “unburned Carbon” resulting from the combustion of Natural Gas or Fuel Oils, Particulate emissions can be calculated by knowing the percentage of Ash in the fuel. Likewise SO<sub>x</sub> emissions can be calculated given the percentage of Sulfur in the fuel.

THC or “Total Hydrocarbons” are rare and effectively negligible but one should be aware of the following when considering both THC and CO emissions ... assuming a suitable level of mixing, hydrocarbons will be thoroughly oxidized (i.e. incinerated) if maintained at a temperature of 1460° F for a “residence time” of at least 0.25 seconds while CO will be thoroughly oxidized if maintained at a temperature of 1600° F for a “residence time” of at least 0.33 seconds. The “residence time” (calculated by knowing the “actual” temperature corrected volumetric flow rate of combustion products and the fired equipment furnace volume) in industrial fired equipment furnaces generally exceeds the requirements, and at the normal levels of operating excess air, the combustion temperatures well exceed the above guidelines.

As to NO<sub>x</sub>, it is well documented that NO<sub>x</sub> emissions are maximized when combustion temperatures are at their peak. This peak temperature is achieved theoretically when there is absolutely

perfect mixing and only the exact requirement of combustion air is inputted (no less or no more) to thoroughly oxidize the combustible matter in the fuel. NO<sub>x</sub> is significantly reduced if there is either an excess of combustion air which reduces the combustion temperature by dilution or a deficiency of combustion air which also lowers combustion temperatures by depriving a portion of the fuel of the air necessary to burn it. Regardless, meeting NO<sub>x</sub> and CO emissions requirements, as well as “Furnace Flame Fit” and “turndown” expectations often times leads to the “NO<sub>x</sub>/CO Box” which is a condition in which the needed reduction in one emission is prevented by the fact that the corrective measure leads to the increase in the other emission.

First, let us review “indicated” versus “dry” versus “corrected” emissions values. “Indicated” emissions values are as the term implies, simply those displayed by the analyzer. One should never presume that these displayed values are either “dry” or “corrected” (some analyzers do have an option for performing the needed mathematics to “correct” the measured values). To obtain “dry” values it is necessary to remove all of the moisture from the flue gas sample (recall that the moisture in the products of combustion can be from 10 to 20% depending on the fuel being fired). This can be accomplished by directing the sample to an ice-cooled sample bottle before directing it to the analyzer. A “corrected” emissions value is one that has been adjusted for an EPA established excess Oxygen level, which varies depending on the fired equipment application. The value for industrial Boilers and HTHW Generators is 3% “dry” O<sub>2</sub> (for duct burner or direct-fired air heaters the value is 15% “dry” O<sub>2</sub>). As an example, a “corrected” NO<sub>x</sub> emissions level for industrial Boilers or HTHW Generators is calculated as follows:

$$\text{Corrected NO}_x, \text{ ppmc} = \text{“Dry” NO}_x, \text{ ppm} \times \frac{(20.9 - 3)}{(20.9 - \text{“Dry” O}_2\%))}$$

For a displayed “wet” emissions level of 50 ppm of CO at an O<sub>2</sub> level of 11% when firing Natural Gas, the actual emissions will increase to about 60 ppm when the sample is “dry” and will further increase to over 100 ppmc when “corrected to 3% O<sub>2</sub>”.

Remember ... to effectively enact “staged combustion” requires that there is a combustion zone which has an excess of combustion air and one that has a deficiency of combustion air, which are then subsequently mixed without residual CO or THC emissions and at a composite excess O<sub>2</sub> level that is as low as possible and ... what is optimal at higher burner firing rates is not necessarily optimal at lower burner firing rates.

“Rules of Thumb”:

- √ In the design region of operating excess air levels, the “corrected” NO<sub>x</sub> will decrease with reductions in excess air while the “Corrected” CO will increase.
- √ When excess O<sub>2</sub> levels increase above 12% CO emissions increase. This because combustion temperatures approach the minimum level required for complete oxidation.

- √ At higher firing rates, fuel and combustion air velocities at the point of mixing are at their most optimal (with the appropriate allowance for “staging”). At reduced firing rates, mixing degrades as the fuel and air velocities decrease. To compensate either the combustion air input, therefore its velocity, can be increased or forced mixing via swirl can be imparted. Though increases in O<sub>2</sub> (up to 12%) and swirl help reduce CO, these tend to increase NO<sub>x</sub>.

**Summary:** *There is, for each specific firing rate a low and most efficient excess air level that gives the lowest “corrected NO<sub>x</sub>” for an acceptable “corrected CO” level (less than 100 ppmc). As the firing rate decreases, this excess air level increases because of the decrease in velocity promoted mixing.*