
19 Duct Burners

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19.1 INTRODUCTION

Linear grid and in-duct burners were used for many years to heat air for drying operations before use in co-generation systems became widespread. Some of the earliest heating systems were merely a gas lance inserted into the air stream. Other systems mixed fuel and air in an often-complicated configuration to fire into a relatively low-temperature recirculating process air stream with oxygen depleted by combustion or water vapor. General use in high-temperature, depleted oxygen streams downstream of gas turbines began in the early 1960s and such systems were used to increase steam production in waste heat boilers for process use in industrial applications, or to drive steam turbine-generators for electrical peaking utility plants. Gas turbines have become larger and more efficient in the intervening years, and duct burner supplemental heat input has increased correspondingly.

Linear burners are applied where it is desired to spread heat uniformly across a duct, whether in ambient air or oxygen-depleted streams. In-duct designs are more commonly used in fluidized bed boilers and small co-generation systems.

19.2 APPLICATIONS

19.2.1 CO-GENERATION

19.2.1.1 Introduction

Co-generation implies simultaneous or consecutive production of two or more forms of energy, most commonly electrical (electric power), thermal (steam, heat transfer fluid, or hot water), and pressure (compressor). For the purposes of this discussion, the basic process involves combustion of fossil fuel in an engine (reciprocating or turbine) that drives an electric generator, coupled with a recovery device that converts the heat from the engine exhaust into a usable energy form.¹ Production of recovered energy can be increased independently of the engine through supplementary firing provided by a special burner type known as a *duct burner* (sometimes called a *grid burner*). Most modern industrial systems will also include flue gas emissions control devices. A typical plant schematic is shown in [Figure 19.1](#).

Reciprocating engines (typically diesel cycle) are often used in smaller systems (10 MW and lower) and offer the advantage of lower capital and maintenance costs but produce relatively high levels of pollutants. Turbine engines are used in both small and large systems (3 MW and above) and, although more expensive, generally emit lower levels of regulated air pollutants.

The fossil fuels used in co-generation systems may consist of almost any liquid or gaseous hydrocarbon, although natural gas and various commercial grades of fuel oil are most commonly used. Mixtures of hydrocarbon gases and hydrogen found in plant fuel systems are often used in “cogen” facilities near refining and petrochemical facilities. Duct burners are capable of firing all fuels suitable for the engine/turbine, as well as many that are not, including heavy oils and waste gases.

Heat recovery for large systems is accomplished in a convective waste heat boiler, commonly referred to as a “heat recovery steam generator” (HRSG). Smaller systems may utilize a steam or hot water boiler, a process heater, or some type of gas-to-gas heat exchanger.

Supplementary firing is often incorporated into the boiler of HRSG design as it can increase thermal input for production of steam as demanded by the process. The device that provides the supplementary firing is a duct burner, so called because it is installed in the duct connecting the engine/turbine exhaust to the heat recovery device, or just downstream of a section of the HRSG superheater (see [Figure 19.2](#) and [Figure 19.3](#)). These systems are often referred to as “duct fired.” The oxygen required for the duct burner combustion process is provided by the residual oxygen

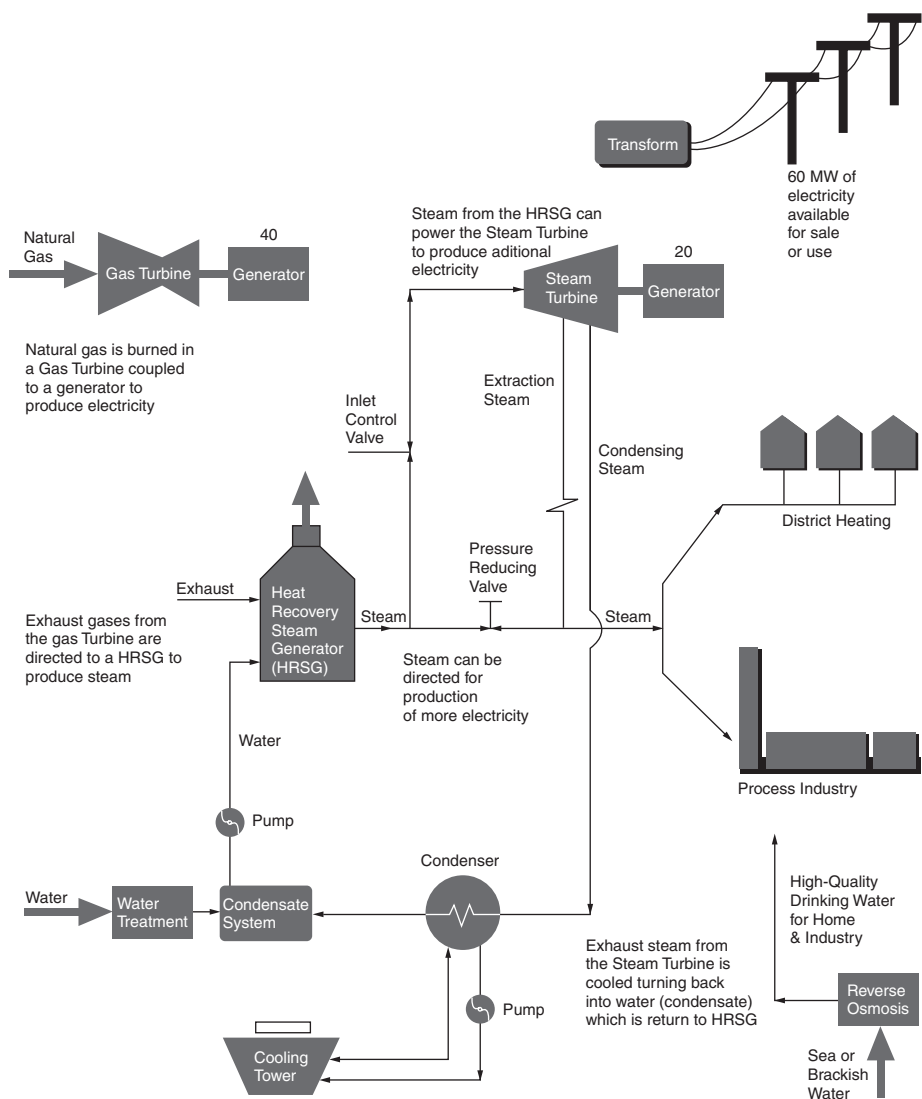


FIGURE 19.1 Typical plant schematic.

in the hot flue gas exhausted from the gas turbine. The flue gas is usually called turbine exhaust gas (TEG) or gas turbine exhaust (GTE).

19.2.1.2 Combined Cycle Systems

Combined cycle systems incorporate all components of the simple cycle configuration with the addition of a secondary electrical production device, usually a steam turbine or generator set powered by the high-pressure steam produced in the HRSG. This arrangement is attractive when the plant cannot be located near an economically viable steam user. Also, when used in conjunction with a duct burner, the steam turbine or generator can provide additional power during periods of high or “peak” demand. The arrangement whereby electricity is generated from the relatively high-grade waste heat before use in a process is called a “topping cycle.”

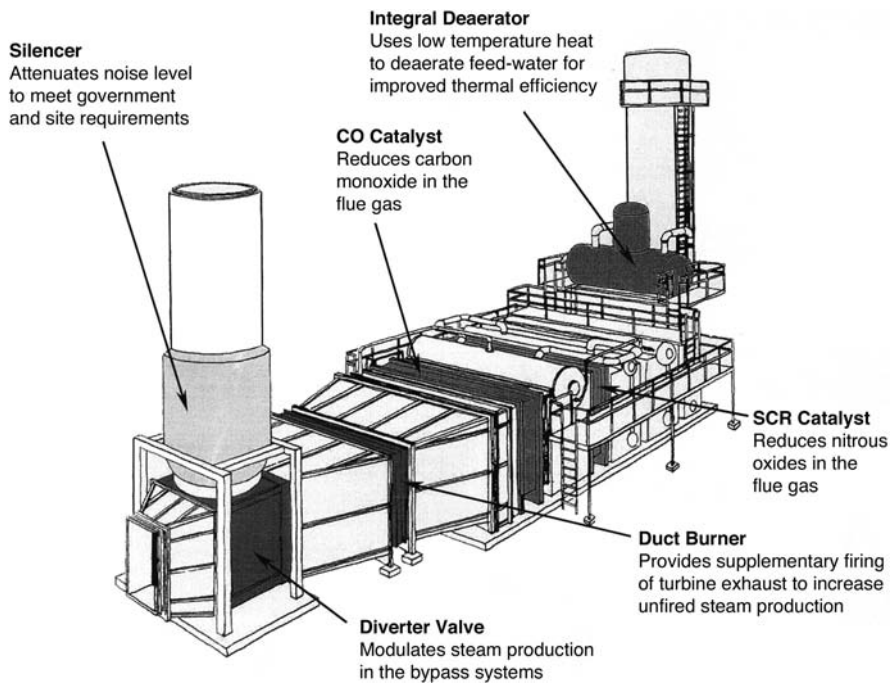


FIGURE 19.2 Typical location of duct burners.

19.2.2 AIR HEATING

Duct burners are suitable for a wide variety of direct-fired air heating applications where the physical arrangement requires mounting inside a duct, and particularly for processes where the combustion air is at an elevated temperature and/or contains less than 21% oxygen. Examples include:

- *Fluidized bed boilers.* Burners are installed in combustion air ducts and are only used to provide heat to the bed during start-up. At cold conditions, the burner is fired at maximum capacity with fresh ambient air, but as combustion develops in the bed, cross exchange with stack gas increases the air temperature and velocity. Burners are shut off when the desired air preheat is reached and the bed can sustain combustion unaided.
- *Combustion air blower inlet preheat.* Burners are mounted upstream of a blower inlet to protect against thermal shock caused by ambient air in extremely cold climates (-40°F ; $^{\circ}\text{C}$ and below). This arrangement is only suitable when the air will be used in a combustion process as it will contain combustion products from the duct burner.
- Drying applications in which isolation of combustion products from the work material is not required. For example, certain paper and wallboard manufacturing operations.

19.2.3 FUME INCINERATION

Burners are mounted inside ducts or stacks carrying exhaust streams primarily composed of air with varying concentrations of organic contaminants. Undesirable components are destroyed both by an increase in the gas stream bulk temperature and through contact with localized high temperatures created in the flame envelope. Particular advantages of the duct burner include higher thermal

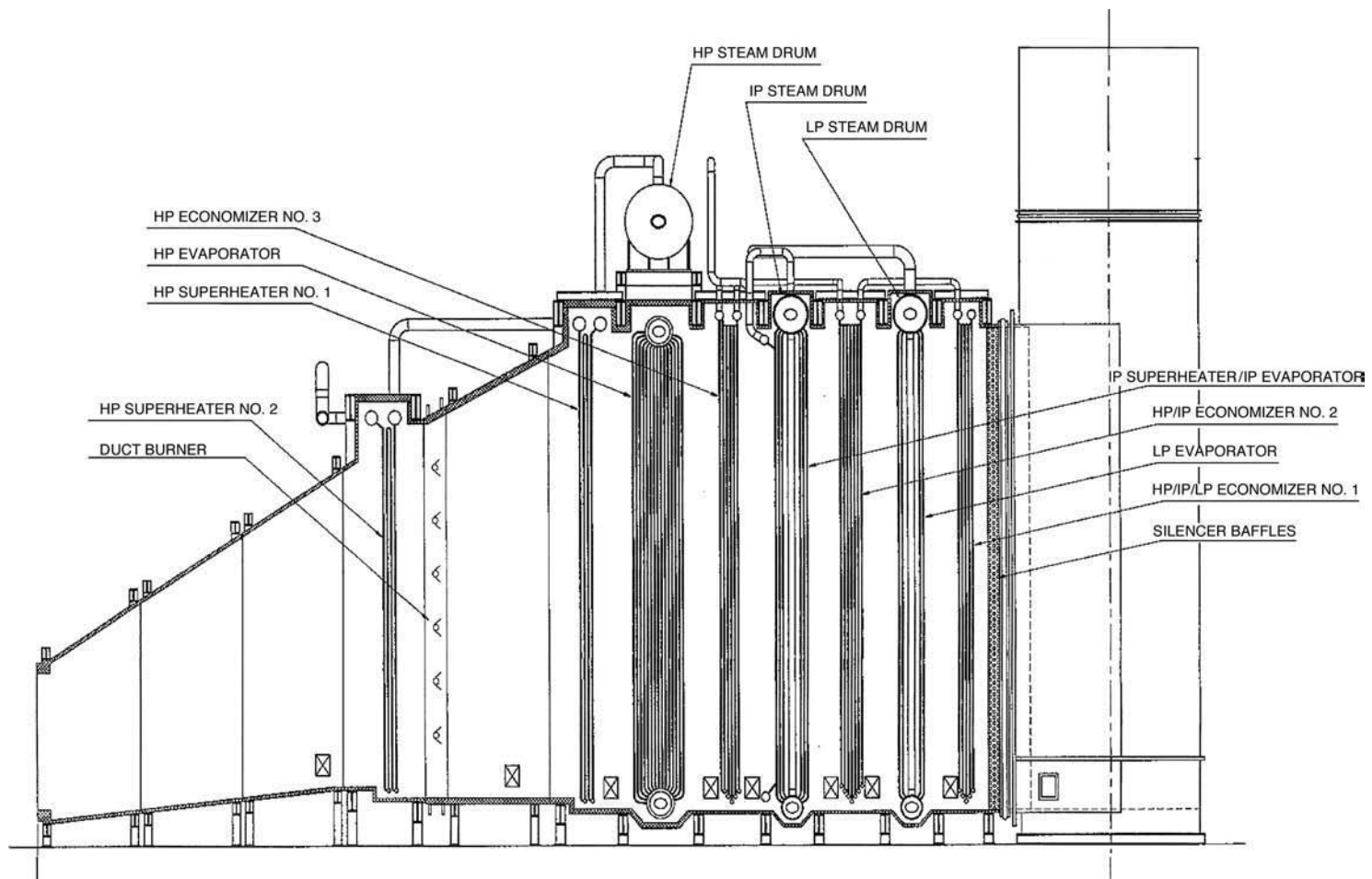


FIGURE 19.3 Schematic of HRSG.

efficiency as no outside air is used, lower operating cost as no blower is required, and improved destruction efficiency resulting from distribution of the flame across the duct section with a grid-type design.

19.2.4 STACK GAS REHEAT

Mounted at or near the base of a stack, the heat added by a duct burner will increase natural draft, possibly eliminating a need for induced-draft or eductor fans. In streams containing a large concentration of water vapor, the additional heat can also reduce or eliminate potentially corrosive condensation inside the stack. An additional source of augmenting combustion air is added if the stack gas oxygen concentration is too low to support combustion. This arrangement may also provide a corollary emissions reduction benefit (see Chapter 19.2.3).

19.3 BURNER TECHNOLOGY

19.3.1 IN-DUCT OR INLINE CONFIGURATION

Register or axial flow burner designs are adapted for installation inside a duct. The burner head is oriented such that flame will be parallel to and co-flow with the air or TEG stream, and the fuel supply piping is fed through the duct sidewall, turning 90° as it enters the burner. Depending on the total firing rate and duct size, only one burner may be sufficient, or several may be arrayed across the duct cross section. In-line burners typically require more air/TEG pressure drop, produce longer flames, and offer a less-uniform heat distribution than the grid type. On the other hand, they are more flexible in burning liquid fuels, can be more easily modified to incorporate augmenting air, and sometimes represent a less-expensive option for high firing rates in small ducts without sufficient room for grid elements.

19.3.2 GRID CONFIGURATION (GAS FIRING)

A series of linear burner elements that span the duct width are spaced at vertical intervals to form a grid. Each element is comprised of a fuel manifold pipe fitted with a series of flame holders (or wings) along its length. Fuel is fed into one end of the manifold pipe and discharged through discrete ports or through multi-port tips at intervals along its length, or through holes drilled directly into the pipe. Gas ports are positioned such that fuel is injected in co-flow with the TEG. The flame stabilizers meter turbine exhaust gas or air flow into the flame zone, thus developing low-pressure zones and eddy currents that anchor ignition. They also shield the flame to maintain suitably high flame temperatures for stability, while also preventing excessive flame cooling which might cause high emissions. Parts exposed to TEG and the flame zone are typically of high-temperature alloy construction.

19.3.3 GRID CONFIGURATION (LIQUID FIRING)

As with the gas-fired arrangement, a series of linear burner elements comprised of a pipe and flame holders (wings) spans the duct width. However, instead of multiple discharge points along the pipe length, liquid fuel is injected at one point per element through the duct sidewall, and directed parallel to the flame holders (cross-flow to the TEG). This configuration utilizes the duct cross section for containment of the flame length, thus allowing a shorter distance between the burner and downstream boiler tubes. The injection device, referred to as a “side-fired oil gun,” utilizes a mechanical nozzle supplemented by low-pressure air (2 to 8 psi) to break the liquid fuel into small droplets (atomization) that will vaporize and burn readily. Although most commonly used for light fuels, this arrangement is also suitable for some heavier fuels where the viscosity can be lowered by heating. In some cases, steam may be required instead of low-pressure air for adequate atomization of heavy fuels.

19.3.4 DESIGN CONSIDERATIONS

19.3.4.1 Fuels

19.3.4.1.1 *Natural Gas*

Natural gas is, by far, the most commonly used fuel as it is readily available in large volumes throughout much of the industrialized world. Because of its ubiquity, combustion characteristics are well understood and most burner designs are developed for this fuel.

19.3.4.1.2 *Refinery/Chemical Plant Fuels*

Refineries and chemical plants are large consumers of both electrical and steam power, which makes them ideal candidates for co-generation. In addition, these plants maintain extensive fuel systems to supply the various direct- and indirect-fired processes, as well as to make the most economical use of residual products. This latter requirement presents special challenges for duct burners, because the available fuels often contain high concentrations of higher molecular weight or unsaturated hydrocarbons with a tendency to condense and/or decompose inside burner piping. The location of burner elements inside the TEG duct, surrounded by high-temperature gases, exacerbates the problem. Plugging and failure of injection nozzles, or even the distribution pipe, may occur, with a corresponding decrease in online availability and increase in maintenance costs.

With appropriate modifications, however, duct burners can function reliably with most hydrocarbon-based gaseous fuels. Design techniques include full insulation of internal burner element manifolds, insulation and heat tracing of external headers and pipe trains, specially designed runners to reduce residence time, and blending of fuel and steam. Steam can also be used to periodically purge the burner elements of solid deposits before plugging occurs, and it may have some value in regasifying deposits via the “Water-Gas Shift” reaction.

19.3.4.1.3 *Low Heating Value*

By-product gases produced in various industrial processes such as blast furnaces, coke ovens, reformers, and flexicokers, or from mature landfills, contain combustible compounds along with significant concentrations of inert components, thus resulting in relatively low heating values (range 50 to 500 Btu/scf). These fuels burn more slowly and at lower peak temperatures than conventional fuels, and thus require special design considerations. Fuel pressure is reduced to match injection velocity to flame speed, and some form of shield or “canister” is employed to provide a protected flame zone with sufficient residence time to promote complete combustion before the flame is exposed to the quenching effects of TEG.

Other design considerations that must be considered include moisture content and particulate loading. High moisture concentration results in condensation within the fuel supply system, which in turn produces corrosion and plugging. Pilots and igniters are particularly susceptible to the effects of moisture because of small fuel port sizes, small igniter gap tolerance, and the insulation integrity required to prevent “shorting” of electrical components. A well-designed system may include a knock-out drum to remove liquids and solids, insulation and heat-tracing of piping to prevent or minimize condensation, and low-point drains to remove condensed liquids. Problems are usually most evident after a prolonged period of shutdown.

Solid particulate can cause plugging in gas injector ports and other fuel system components and should therefore be removed to the maximum practical. In general, particle size should be no greater than 25% of the smallest port, and overall loading should be no greater than 5 ppm by volume (weight).

19.3.4.1.4 *Liquid Fuels*

In co-generation applications, duct burners are commonly fired with the same fuel as the turbine, which is typically limited to light oils such as no. 2 diesel, kerosene, or naphtha. For other applications, specially modified side-fired guns or an in-line design can be employed to burn heavier oils such as no. 6 and some waste fuels.

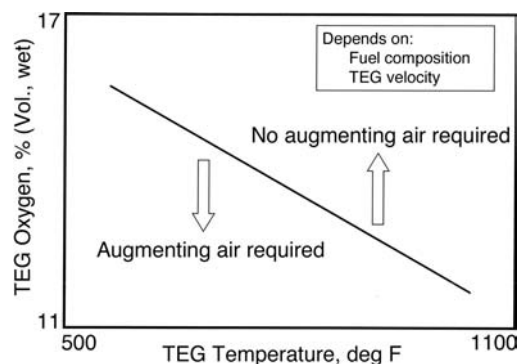


FIGURE 19.4 O_2 vs. temperature.

19.3.4.2 Combustion Air and Turbine Exhaust Gas

19.3.4.2.1 Temperature and Composition

Oxygen used for supplementary firing in HRSG co-generation applications is provided by the residual in the turbine exhaust gas instead of from an external source of air. Because this flue gas is already at an elevated temperature, duct burner thermal efficiency can approach 100%, as relatively little heat is required to raise the combustion product temperature to the final fired temperature entering the boiler. TEG, however, contains less oxygen than fresh air, typically between 11 and 16% by volume, which in conjunction with the TEG temperature significantly affects the combustion process. As the oxygen concentration and TEG temperature decrease, products of incomplete combustion (CO and unburned hydrocarbons) occur more readily, eventually progressing to combustion instability. The effect of low oxygen concentrations can be partially offset by higher temperature; and, conversely, higher oxygen concentrations will partially offset the detrimental effects of low TEG temperatures. This general relationship is depicted graphically by Figure 19.4. Duct burner emissions are discussed in more detail elsewhere in this chapter.

One measure used to predict potential combustion success is the calculated adiabatic flame temperature with a stoichiometric mixture. The burner can then be designed to create a local high-temperature condition for stable combustion, while not allowing premature quenching by the remaining excess TEG. Flame speed is another measure of combustibility and can be calculated for unusual fuel constituents.

The oxygen remaining from the turbine combustion is usually many times greater than required for supplemental firing. The final concentration of O_2 after supplemental firing is frequently still above 10%. In the extreme, a fully fired boiler is possible, with the residual O_2 as low as 2%. Fully fired HRSGs can produce large amounts of steam but are rare because the economics favor the power-to-heat ratio of unfired or supplemental fired HRSG.

19.3.4.2.2 Turbine Power Augmentation

During periods of high electrical demand, various techniques are employed by turbine suppliers to increase power output, and most methods increase the concentration of water vapor in the TEG. The corresponding effect is a reduction in TEG oxygen concentration and temperature with consequent effects on duct burner combustion. Depending on the amount of water vapor used, CO emissions may simply rise or, in extreme cases, the flame may become unstable. The former effect can be addressed with an allowance in the facility operating permit or by increasing the amount of CO catalyst in systems so equipped. The latter requires air augmentation for the duct burner, a process wherein fresh air is injected at a rate sufficient to raise the TEG oxygen concentration to a suitable level.

19.3.4.2.3 Velocity and Distribution

Regardless of whether TEG or fresh air is used, velocity across the flame stabilizers must be sufficient to promote mixing of the fuel and oxygen, but not so great as to prevent the flame from anchoring

to the burner. Grid-type configurations can generally operate with velocities ranging from 20 to 90 fps (feet per second) and pressure drops of less than 0.5 inches water column (in. w.c.). In-line or register burners typically require velocities of 100 to 150 fps with a pressure drop of 2 to 6 in. w.c.

Grid burners are designed to distribute heat uniformly across the HRSG or boiler tube bank, and thus require a reasonably uniform distribution of TEG or air to supply the fuel with oxygen. Nonuniform distribution creates localized areas of low velocity resulting in poor flame definition along with high emissions of CO and unburned hydrocarbons. In addition, the variable flows will affect the burner flame length and boiler inlet temperature profile. Gas turbine exhaust flow patterns combined with the rapidly diverging transition duct will almost always produce an unsatisfactory flow profile that must be corrected by means of a redistribution or straightening device. Likewise, the manner in which an alternate ambient air source is introduced into a duct may also result in flow maldistribution requiring some level of correction. Selection and design of flow straightening devices are discussed elsewhere in this chapter.

In instances where the bulk TEG or air velocity is lower than that required for proper burner operation, flow straightening alone is not sufficient. It becomes necessary to restrict a portion of the duct cross section at or near the plane of the burner elements, thereby increasing the “local” velocity across flame holders. This restriction, also referred to as “blockage,” commonly consists of unfired runners or similar shapes uniformly distributed between the firing runners. The extra blockage is almost always needed for duct burners embedded in the superheater section of the HRSG, and less often required for duct burners located in the inlet transition duct. The designer must also account for the exhaust gas flow conditions at various turbine load and ambient air temperature.

In-line or register burners inject fuel in only a few (or possibly only one) positions inside the duct, and can therefore be positioned in an area of favorable flow conditions, assuming the flow profile is known. On the other hand, downstream heat distribution is less uniform than with grid designs and flames may be longer. As with grid-type burners, in some cases it may be necessary to block portions of the duct at or just upstream of the burners to force a sufficient quantity of TEG or air through the burner.

19.3.4.2.4 Ambient Air Firing (air-only systems and HRSG backup)

Velocity and distribution requirements for air systems are similar to those for TEG, although inlet temperature is not a concern because of the relatively higher oxygen concentration. As with TEG applications, the burner elements are exposed to the products of combustion, so material selection must take into account the maximum expected fired temperature.

Ambient (or fresh) air backup for HRSGs presents special design challenges. Because of the temperature difference between ambient air and TEG, designing for the same mass flow and fired temperature will result in velocity across the burner being approximately one-third that of the TEG case. Reducing the air flow to save on fan horsepower may make the design unwieldy or impossible. If the cold-condition velocity is outside the acceptable range, it will be necessary to add blockage, as described elsewhere in this chapter. Fuel input capacity must also be increased to provide the heat required to raise the air from ambient to the design firing temperature. By far, the most difficult challenge is related to flow distribution. Regardless of the manner in which backup air is fed into the duct, a flow profile different from that produced by the TEG is virtually certain. Flow straightening devices can therefore not be optimized for either case, but instead require a compromise design to provide acceptable flow distribution and pressure drop results for both operating modes. If the two flow patterns are radically different, it may ultimately be necessary to alter the air injection arrangement independent of the TEG duct straightening device.

19.3.4.3 Augmenting Air

As turbines have become more efficient and more work is extracted in the form of, for example, electricity, the oxygen level available in the TEG continues to decrease. To some extent, a correspondingly higher TEG temperature provides some relief for duct burner operation.

In some applications, however, an additional oxygen source may be required to augment that available in the turbine exhaust gas when the oxygen content in the TEG is not sufficient for combustion at the available temperature of the TEG. If the mixture adiabatic flame temperature is not high enough to sustain a robust flame in the highly turbulent stream, the flame may become unstable.

The problem can be exacerbated when the turbine manufacturer adds large quantities of steam or water for NO_x control and power augmentation. A corresponding drop in TEG temperature and oxygen concentration occurs because of dilution. The TEG temperature is also reduced in installations where the HRSG manufacturer splits the steam superheater and places tubes upstream of the duct burner.

By combining results from field measurements with data from their research and development facilities, manufacturers have defined the oxygen requirement with respect to TEG temperature and fuel composition and are able to quantify the amount of augmenting air required under most conditions likely to be encountered. In cases where augmenting air is required, the flow may be substantial — from 30 to 100% of the theoretical air required for the supplemental fuel. It is not normally feasible to raise the level of oxygen in the entire stream to an acceptable level, so it is raised only in the locality of the burner in specially designed systems.

The augmenting air runner of one manufacturer consists of a graduated air delivery tube designed to ensure constant velocity across the length of the tube. Equal distribution of augmenting air across the face of the tube is imperative. The augmenting air is discharged from the tube into a plenum and passes through a second distribution grid to further equalize the flow. The air passes through perforations in the flame holder where it is intimately mixed with the fuel in the primary combustion zone. This intimate mixing ensures corresponding low CO and UHC emissions under most conditions likely to be encountered. Once the decision has been made to supply augmenting air to a burner, it is an inevitable result of the design that the augmenting air will be part of the normal operating regime of the combustion runner.

19.3.4.4 Equipment Configuration and TEG/Combustion Air Flow Straightening

The turbine exhaust gas/combustion air velocity profile at the duct burner plane must be within certain limits to ensure good combustion efficiency and, in co-generation applications, this is rarely achieved without flow straightening devices. Even in nonfired configurations, it may be necessary to alter the velocity distribution to make efficient use of the boiler heat transfer surface. [Figure 19.6](#) shows a comparison of flow variation with and without flow straightening.

The modern HRSG has become a huge structure, often rising five stories in the air and up to four times as wide as their 1960-era ancestors. The duct burners are commonly positioned in the TEG inlet duct, either upstream of the first bank of heat transfer tubes or nested in the boiler superheater section between banks of tubes. In the former case, a straightening device would be mounted just upstream of the burner, while in the latter, it is mounted either upstream of the first tube bank or between the first tube bank and (upstream of) the burner. Although not very common, some HRSG design configurations utilize two stages of duct burners with heat transfer tube banks in between and a flow straightening device upstream of the first burner. Such an arrangement is, however, problematic, because the TEG downstream of the first stage burner may not have the required combination of oxygen and temperature properties required for proper operation of the second stage burner.

Perforated plates extending across the entire duct cross section are most commonly used for flow straightening, because experience has shown they are less prone to mechanical failure than vane-type devices, although they require a relatively high pressure drop. The pattern and size of perforations can be varied to achieve the desired distribution. Vanes can produce comparable results with significantly less pressure loss, but require adequate structural reinforcement to withstand the flow-induced vibration inherent in HRSG systems. Regardless of the method used, flow pattern complexity, particularly in TEG applications, usually dictates the use of either physical or computational fluid dynamics (CFD) modeling for distributor design optimization (see [Figure 19.5](#)).

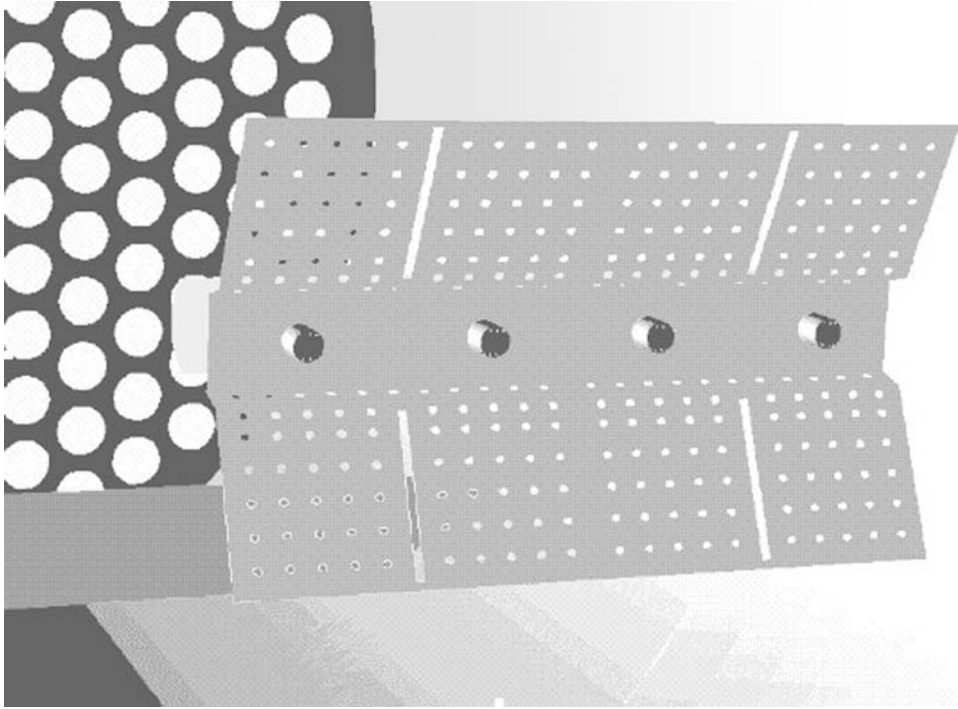


FIGURE 19.5 CFD model of duct burner element.

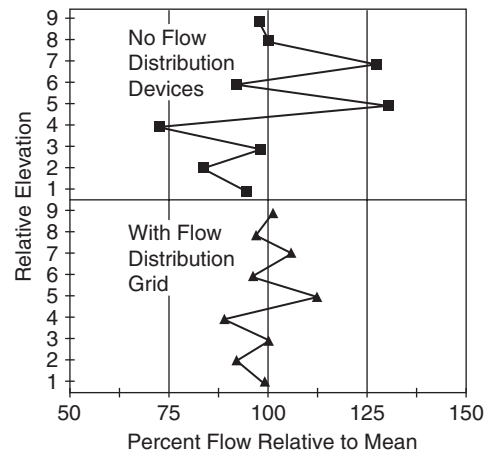


FIGURE 19.6 Comparison of flow variation with and without straightening device.

19.3.4.4.1 Physical Modeling

TEG/air flow patterns are determined by inlet flow characteristics and duct geometry, and are subject to both position and time variation. The design of an efficient (low pressure loss) flow-straightening device is therefore not a trivial exercise, and manual computational methods are impractical. Historically, physical models, commonly 1:6 to 1:12 scale, are constructed, and flow characteristics are analyzed by measuring pressure or velocity and by flowing air with smoke tracers or water with polymer beads through the model (see [Figure 19.7](#)). The simulation velocity is maintained in

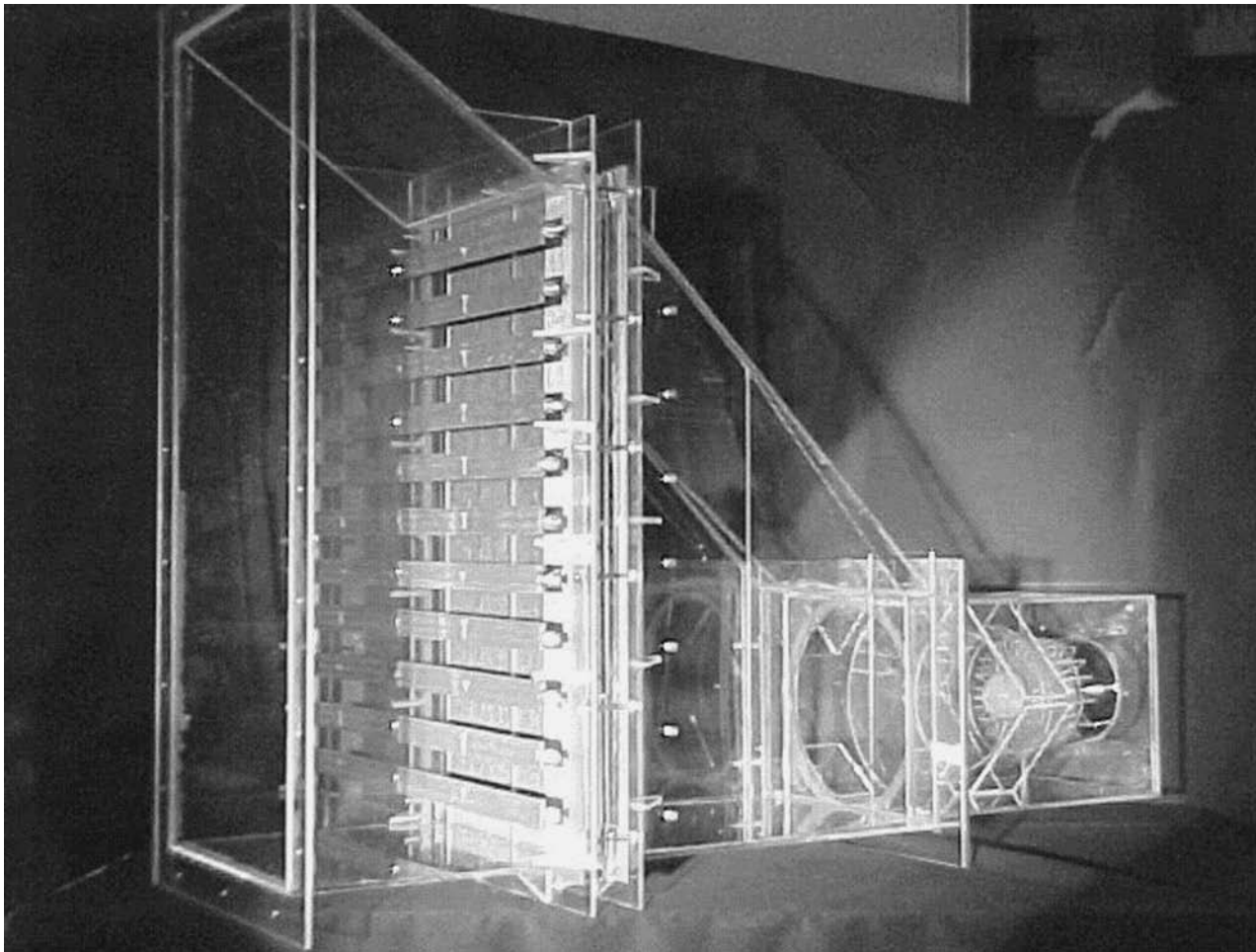


FIGURE 19.7 Physical model of burner.

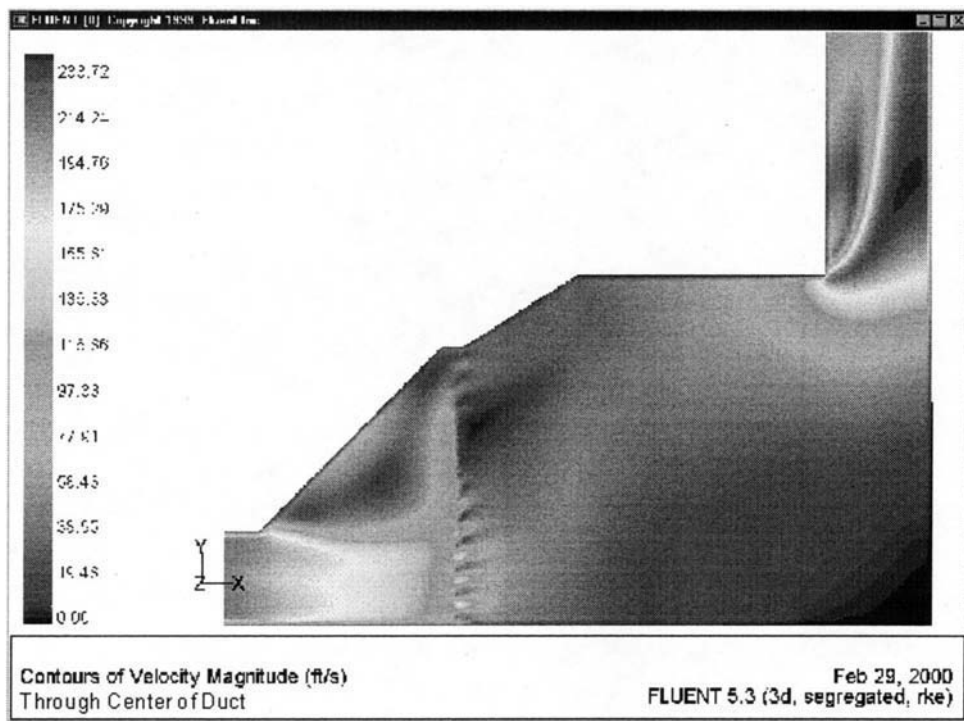


FIGURE 19.8 Sample result of CFD modeling performed on a burner.

the turbulent flow regime for scaling but may not be directly related to the actual condition. This method is generally accepted and produces reasonable results, although the tests conducted at ambient conditions (known as “cold flow”) are not capable of simulating buoyant effects that may occur at elevated temperatures.

19.3.4.4.2 Computational Fluid Dynamic (CFD) Modeling

Flow modeling with CFD, using a computer-generated drawing of the inlet duct geometry, is capable of predicting flow pattern and pressure drop in the turbine exhaust flow path. The model can account for swirl flow in three dimensions to accurately predict pressure drop and to subsequently design a suitable device to provide uniform flow. The CFD model must be quite detailed to calculate flow patterns incident and through a perforated grid or tube bank, while also keeping the overall model solution within reasonable computation time. Care must be taken to evaluate the model because shortcuts to reduce complexity by assuming symmetry may hide the adverse effect of turbine-induced swirl. Combustion effects can be included in the calculations at the cost of increased computation time. Emissions calculations are not yet reliable, however. [Figure 19.8](#) shows a sample result of CFD modeling performed on an HRSG inlet duct.

19.3.4.5 Wing Geometry Variations

19.3.4.5.1 Flame Holders

Design of the flame stabilizer, or flame holder, is critical to the success of supplementary firing. Effective emission control requires that the TEG be metered into the flame zone in the required ratio to create a combustible mixture and ensure that the combustion products do not escape before the reactions are complete. Each duct burner manufacturer has developed proprietary designs in response to new turbine and HRSG design requirements, to enable them to provide the desired results.

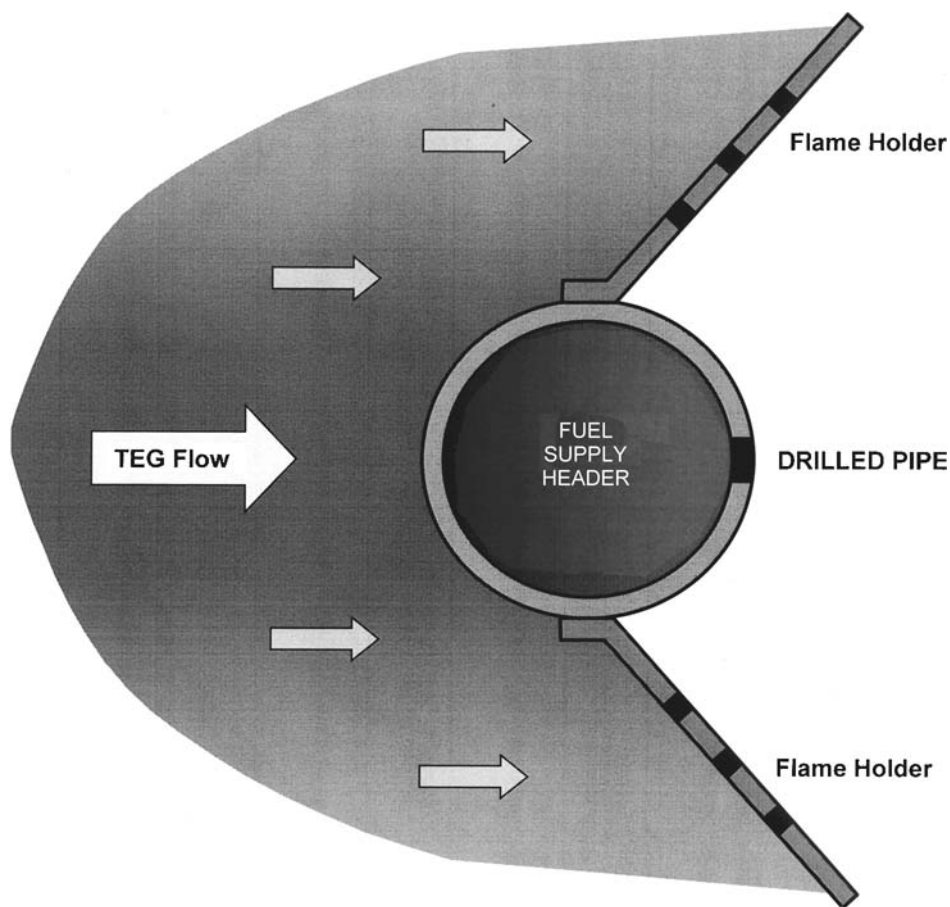


FIGURE 19.9 Drilled pipe duct burner.

19.3.4.5.2 Basic Flame Holder

In its basic form, a fuel injection system and a zone for mixing with oxidant are all that is required for combustion. For application to supplemental firing, the simple design shown in [Figure 19.9](#) consists of an internal manifold or “runner,” usually an alloy pipe with fuel injection orifices spaced along the length. A bluff body plate, with or without perforations, is attached to the pipe to protect the flame zone from the turbulence in the exhaust gas duct. The low-pressure zone pulls the flame back onto the manifold. This primitive runner may overheat the manifold and cause distortion of the metallic parts and internal coking. Emissions are unpredictable with changing geometry and CO is usually much higher than the current typically permitted levels of 0.04 to 0.1 lb/MMBtu (HHV basis).

19.3.4.5.3 Low Emissions Design

Modifications to the design for lower emission performance generally include a larger cross section in the plane normal to the exhaust flow. The increased blocked area protects the fuel injection zone and increases residence time. The NO_x is reduced by staging the oxygen-depleted TEG; the CO/UHC is reduced by the delayed quenching and back mixing. The correct flow rate of TEG is metered through orifices in the flame holder, and the fuel injection velocity and angle are designed to enhance combustion efficiency. The flame zone is pushed away from the internal manifold

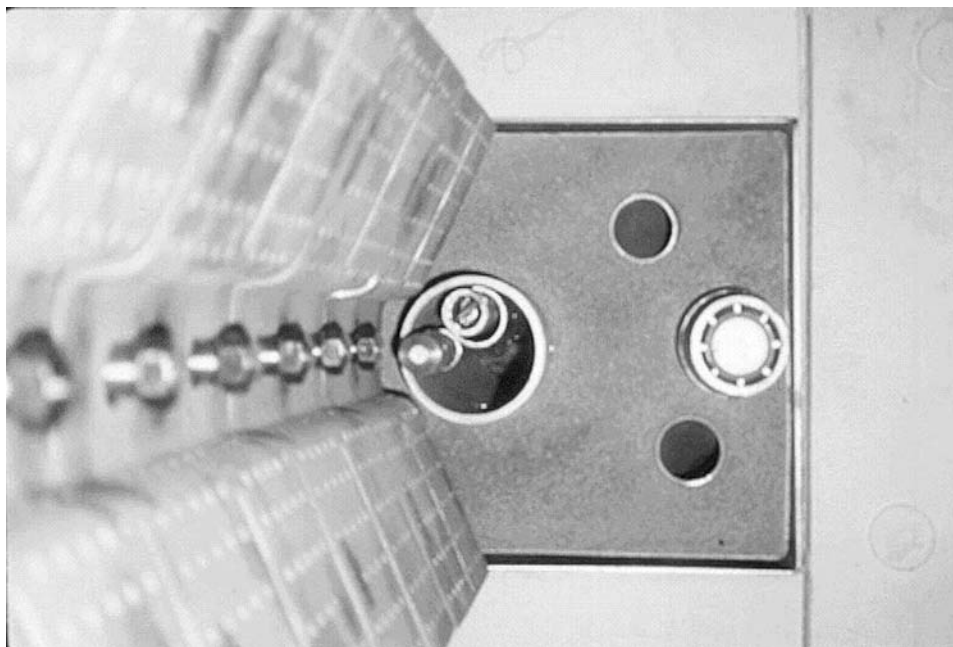


FIGURE 19.10 Low-emission duct burner.

(“runner” pipe), creating space for cooling TEG to bathe the runner and flame holder and enhance equipment life.

Each manufacturer approaches the geometry somewhat differently. Some manufacturers use cast alloy pieces welded together to provide the required blockage. These standard pieces are difficult to customize to specific applications and often add significant weight. Hot burning fuels, such as hydrogen, may not receive the cooling needed to protect the metal from oxidation. Alternately, fuels subject to cracking (e.g., propylene) may not have the oxygen needed to minimize coke build-up.

Another manufacturer supplies custom designs to accommodate velocity extremes, while maintaining low emissions. In the design shown in [Figure 19.10](#), the flame holder is optimized with CFD and research experimentation to enhance mixing and recirculation rate. Special temperature-resistant materials of construction are easily accommodated. This supplier also uses patented removable fuel tips with multiple orifices, which can be customized to counteract any unexpected TEG flow distribution discovered after commercial operation. [Figure 19.11](#) depicts the flow patterns of air/TEG and fuel in relation to the typical duct burner flame holder.

19.3.4.6 Emissions

19.3.4.6.1 *NO_x and NO vs. NO₂*

Formation of NO and NO₂ is the subject of ongoing research to understand the complex reactions (see Chapter 6). Potentially, several oxides of nitrogen (NO_x) can be formed during the combustion process, but only nitric oxide (NO) and nitrogen dioxide (NO₂) occur in significant quantities. NO is colorless and NO₂ has a reddish-brown color.

In the elevated temperatures found in the flame zone in a typical HRSG turbine exhaust duct, NO formation is favored almost exclusively over NO₂ formation. Turbine exhaust NO_x was historically 95% NO and 5% NO₂, although newer turbines have increased this ratio to 70/30. In the high temperature zone, NO₂ dissociates to NO via the following mechanism:



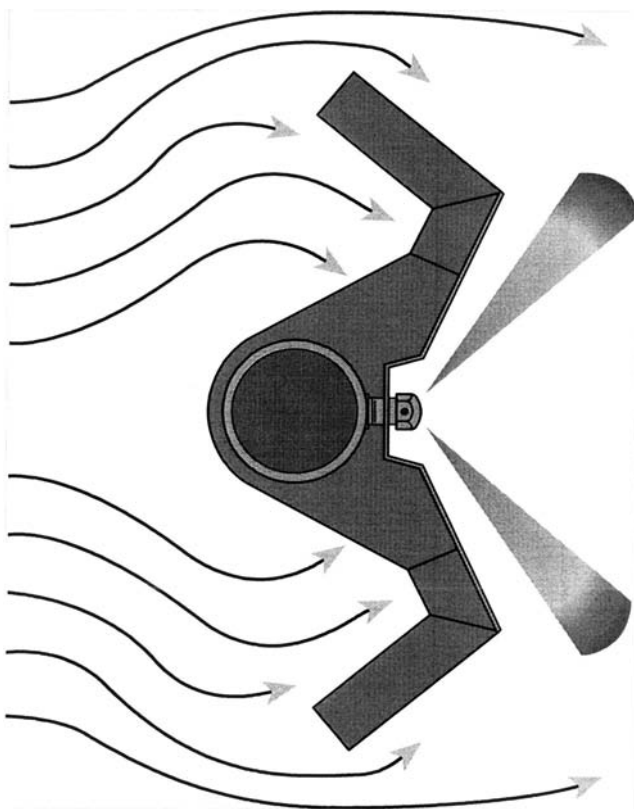
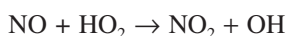


FIGURE 19.11 Flow patterns around flame stabilizer.

However, after the TEG exits the hot zone and enters the cooling zone at the boiler tubes, reaction slows and the NO_2 is essentially fixed. At the cooler stack outlet, the entrained NO is very slowly oxidized to NO_2 through a complex photochemical reaction with atmospheric oxygen. The plume will be colorless unless the NO_2 increases to about 15 ppm, at which time a yellowish tint is visible. Care must be taken in duct burner design because NO can also be oxidized to NO_2 in the immediate post-flame region by reactions with hydroperoxyl radicals:



if the flame is rapidly quenched. This quenching can occur because of the large quantity of excess TEG commonly present in duct burner applications. Conversion to NO_2 may be even higher at fuel turn-down conditions where the flame is smaller and colder. NO_2 formed in this manner can contribute to “brown plume” problems and may even convert some of the turbine exhaust NO to NO_2 . Co-generation units with catalyst to oxidize CO will have an increase in NO_2 and SO_3 content, which must be considered in the design of the NO_x removal system.

There are two principle mechanisms in which nitrogen oxides are formed:

1. *Thermal NO_x* . The primary method is thermal oxidation of atmospheric nitrogen in the TEG by combustion-generated oxygen free radicals by way of the Zeldovitz mechanism. NO_x formed in this way is called *thermal NO_x* . As the temperature increases in the combustion zone and surrounding environment, increased amounts of nitrogen (N_2) and

oxygen (O_2) from the TEG are ionized and converted to NO. Thermal NOx formation is predominant in the peak temperature zones of the flame.

2. *Fuel-Bound Nitrogen NOx*. The secondary method to form NOx is the reaction of oxygen with nitrogen that is chemically bound in compounds contained in the fuel. NOx formed in this manner is called *fuel* NOx. Large amounts of NOx can be formed by fuels that contain molecularly bound nitrogen, such as, for example, amines and cyanates. If a gaseous fuel such as natural gas contains diluent N_2 , it simply behaves as atmospheric nitrogen and will form NOx only if it disassociates in the high-temperature areas. However, if the gaseous fuel contains, for example, ammonia (NH_3), this nitrogen is considered to be bound. In the low concentrations typically found in gaseous fuels, the conversion to NOx is close to 100% and can have a major impact on NOx emissions.

Bound nitrogen in liquid fuel is contained in the long carbon chain molecules. Distillate oil is the most common oil fired in duct burners as a liquid fuel. The fuel-bound nitrogen content is usually low, in the range of 0.05 weight percent. Conversion to NOx is believed to be 80 to 90%. For no. 6 oil, containing 0.30 weight percent nitrogen, the conversion rate to NOx would be about 50%. Other heavy waste oils or waste gases with high concentrations of various nitrogen compounds may add relatively high emissions. Consequently, fuel NOx can be a major source of nitrogen oxides and, in liquid firing, may predominate over thermal NOx.

The impact of temperature on NOx production in duct burners is not as pronounced as in, for example, fired heaters or package boilers. One reason is that both the bulk fired temperature and the adiabatic flame temperature are lower than in fired process equipment.

When used to provide supplementary firing of turbine exhaust, duct burners are generally considered to be “low-NOx” burners. Because the turbine exhaust contains reduced oxygen, the peak flame temperature is reduced and the reaction speed for O_2 and free radical N^+ to form NOx is thus lowered. The burners also fire into much lower average bulk temperatures, usually less than 1600°F, than, for example, process burners or fired boilers. The high-temperature zones in the duct burner flames are smaller due to large amounts of flame quenching by the excess TEG. Finally, mixing is rapid and therefore retention time in the high-temperature zone is very brief.

The same duct burner, when used to heat atmospheric air, is no longer considered “Low NOx” because the peak flame temperature approaches the adiabatic flame temperature in air.

Clearly, operating conditions have a major impact on NO formation during combustion. To properly assess NOx production levels, the overall operating regime must be considered, including TEG composition, fuel composition, duct firing temperature, and TEG flow distribution.

19.3.4.6.2 Visible Plumes

Stack plumes are caused by moisture and by impurities in the exhaust. Emitted NO is colorless and odorless while NO_2 is brownish in color. If the NO_2 level in the flue gas exceeds about 15 to 20 ppm, the plume will take on a brownish haze. NOx also reacts with water vapor to form nitrous and nitric acids. Sulfur in the fuel may oxidize to SO_3 and react with condensate or ammonia in the stack effluent, causing a more persistent white plume. Both nitric acid and sulfuric acid are components of “acid rain.”

19.3.4.6.3 CO, VOC, Sox, and Particulate

Carbon Monoxide. Carbon monoxide (CO), a product of incomplete combustion, has become a major permitting concern in gas turbine-based co-generation plants. Generally, CO emissions from modern industrial and aero-derivative gas turbines are very low at the design condition, in the range of a few parts per million (ppm). There are occasional situations in which CO emissions from the turbine increase because of a high rate of water injection for NOx control or at operation at partial load. The primary concern in this section is the potentially large CO contribution from supplementary firing. The same low-temperature combustion environment that suppresses NOx formation is

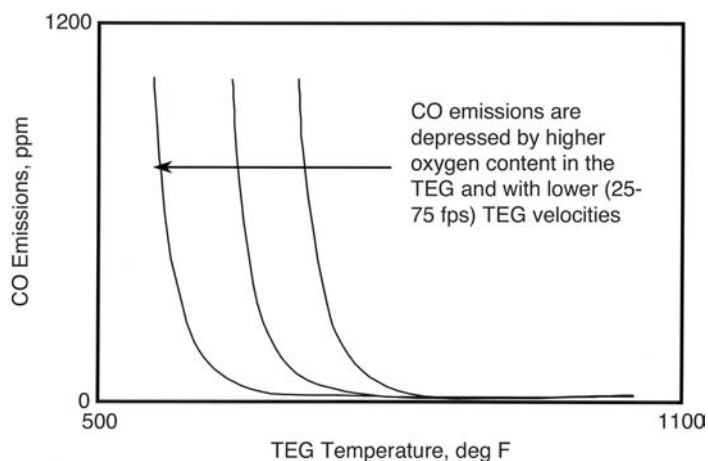


FIGURE 19.12 Effect of conditions on CO formation.

obviously unfavorable for complete oxidation of CO to CO₂. Increased CO production occurs when a fuel is combusted under fuel-rich conditions or when a flame is quenched before complete burnout. These conditions causing CO production (see Figure 19.12) can occur if there is poor distribution of TEG to the duct burner which, in the extreme, causes some burner elements to fire fuel-rich and others fuel-lean, depending on the efficiency of the TEG distribution device. The downstream residence time is seldom long enough to allow the extra CO to mix and completely react with the excess oxygen.

The factors affecting CO emissions include:³

- Turbine exhaust gas maldistribution
- Low TEG approach temperature
- Low TEG oxygen content
- Flame quench on “cold” screen tubes
- Improperly designed flame holders that allow flame quench by relatively cold TEG
- Steam or water injection
- Low firing rate promoting quenching
- Insufficient residence time or burnout distance

Unburned Hydrocarbons (UHCs). In a mechanism similar to CO generation, unburned hydrocarbons are formed in the exhaust gas when fuel is burned without sufficient oxygen, or if the flame is quenched before combustion is complete. UHCs can consist of hydrocarbons (defined as any carbon-hydrogen molecule) of one carbon or multiple carbon molecules. The multiple carbon molecules are often referred to as long-chain hydrocarbons. Unburned hydrocarbons are generally classified in two groups:

1. Unburned hydrocarbons reported as methane
2. Nonmethane hydrocarbons or volatile organic compounds (VOCs)

The reason for the distinction and greater concern for VOCs is that longer chain hydrocarbons play a greater role in the formation of photochemical smog. VOCs are usually defined as molecules of two carbons or greater, or sometimes three carbons or greater. These definitions are set by local air quality control boards and vary across the United States.

UHCs can be reduced by correct combustion of the fuel and by a CO oxidation catalyst. However, hydrocarbon compounds will always be present in trace quantities, regardless of how the HRSG system is operated. Both UHCs and VOCs are typically higher when firing with liquid fuels.

Sulfur Dioxide. Sulfur dioxide (SO_2) is a colorless gas that has a characteristic smell in concentrations as low as 1 ppm. Sulfur dioxide is formed when sulfur (S) in the fuel combines with oxygen (O_2) in the TEG. If oxygen is present (from excess of combustion) and the temperature is correct, the sulfur will further combine and be converted to sulfur trioxide (SO_3). SO_2 is also converted to SO_3 by the CO oxidation catalyst. These oxides of sulfur are collectively known as SO_x .

Except for sulfur compounds present in the incoming particulate matter, all of the sulfur contained in the fuel is converted to SO_2 or SO_3 . Sulfur dioxide will pass through the boiler system to eventually form the familiar “acid rain” unless a gas-side scrubbing plant is installed. Sulfur trioxide can, in the cooler stages of the gas path, combine with moisture in the exhaust gas to form sulfuric acid (H_2SO_4). This material is highly corrosive and will be deposited in ducts and the economizer, if the exhaust gas is below condensing temperatures. Natural gas fuels are, fortunately, very low in sulfur and do not usually cause a problem. However, some oil fuels and plant gases can be troublesome in this respect.

Particulate Matter (PM). Particulate emissions are formed from three main sources: ash contained in liquid fuels, unburned carbon in gas or oil, and SO_3 . The total amount of particulate is often called TSP (total suspended particulate). There is a concern for the smaller sized portion of the TSP, as this stays suspended in air for a longer period of time. The PM-10 is the portion of the total particulate matter that is less than 10 microns (1×10^{-6} m) in size. Particles smaller than PM-10 are on the order of smoke.

Typical NO_x and CO emissions for various fuels are shown in Table 19.1.

19.3.5 MAINTENANCE

19.3.5.1 Normal Wear and Tear

If nothing has been replaced in the past 5 years and the burner (or turbine/HRSG set) is operated fairly continuously, it is likely that some tips, pilot parts, or flame stabilizers may require replacement.

TABLE 19.1
Typical NO_x and CO Emissions from Duct Burners

Gas	NO_x (lb/ 10^6 Btu Fired)	CO (lb/ 10^6 Btu Fired)
Natural gas	0.10	0.04–0.08
Hydrogen gas	0.15	0.00
Refinery gas	0.1–0.15	0.03–0.08
Plant gas	0.11	0.04–0.01
Flexicoker gas	0.08	0.01
Blast furnace gas	0.03–0.05	0.12
Producer gas	0.05–0.1	0.08
Syn fuels	0.08–0.12	0.08
Propane	0.14	0.12
Butane	0.14	0.12

Note: NO_x emissions from butane and propane can be modified by direct steam injection into gas or burner flame. CO emissions are highly dependent on residence time, TEG approach temperature, and HRSG fired temperature.

19.3.5.2 Damage

This refers to damage due to misuse, system upsets, or poor maintenance practices. Older systems designed without sufficient safety interlocks (TEG trip, high temperature) sometimes expose parts to excessively high temperatures, which results in equipment warpage and oxidation failure. Because of the severe conditions, it is not always possible to predict where failure might occur.

19.3.5.3 Fuel Quality/Composition

Some refinery fuels or waste fuels contain unsaturated components and/or liquid carryover. Eventually, these compounds will form solids in the runner pipes or directly in tips, which results in plugging and eventual failure. Products of corrosion may also accumulate in fuel piping, particularly when the burner is fired intermittently.

The following are some items to look for when operational problems are encountered:

- *Plugged gas ports, which are evidenced by gaps in the flame or high fuel pressure.* Gas ports may simply consist of holes drilled into the element manifold pipe, or they may be located in individual removable tips. Designs of the former type may be re-drilled or else the entire manifold pipe must be replaced. Discrete tips can be replaced individually, as required.
- *Warped flame holders (wings).* Some warping is normal and will not affect flame quality, but excessive deformation such as “curling” around the gas ports will degrade the combustion and emissions performance. Most grid-type burner designs permit replacement of individual flame holder segments.
- *Oxidation of flame holders (wings) or portions of flame holders.* If more than one quarter of the flame holder is missing, it is a good candidate for replacement. Fabricated and cast designs are equally prone to oxidation over time. If oxidation is caused by flame recirculation behind the runner, the TEG flow should be modified to remove the recirculation. Most grid-type burner designs permit replacement of individual flame holder segments. For hot burning fuels (hydrogen and unsaturated hydrocarbons), materials suitable for higher temperatures may be substituted.
- *Severe sagging of runner pipes (grid design only).* If the manifold pipe is no longer supported at both ends, it should be replaced. Beyond that relatively extreme condition, sagging at midspan in excess of approximately 1 to 2 inches (3 to 5 cm) per 10 ft of length should be corrected by runner replacement and/or installation of an auxiliary support.

19.3.6 ACCESSORIES

19.3.6.1 Burner Management System

All fuel burning systems should incorporate controls that provide for safe manual light-off and shutdown, as well as automatic emergency shutdown upon detection of critical failures. Control logic may reside in a packaged flame safeguard module, a series of electromechanical relays, a programmable logic controller (PLC), or a distributed control system (DCS). At a minimum, the duct burner management system should include following:

- Flame supervision for each burner element
- Proof of completed purge and TEG/combustion air flow before ignition can be initiated
- Proof of pilot flame before main fuel can be activated
- Automatic fuel cutoff upon detection of flame failure, loss of TEG/combustion air, and high or low fuel pressure

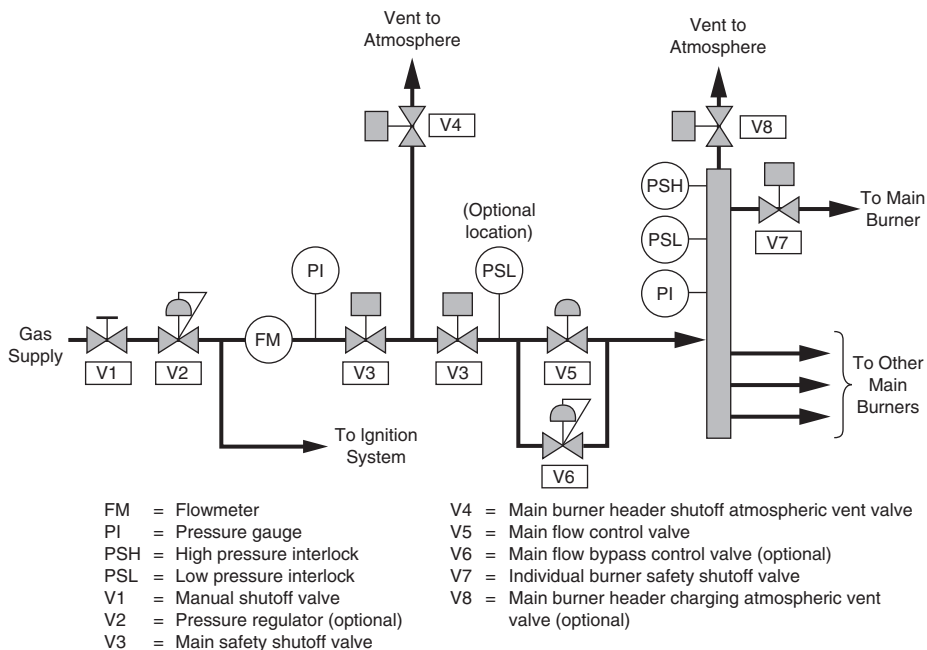


FIGURE 19.13 Typical main gas fuel train: multiple elements with individual firing capability.

Other interlocks designed to protect downstream equipment may also be included, such as high boiler tube temperature or loss of feed water.

19.3.6.2 Fuel Train

Fuel flow to the burners is controlled by a series of valves, safety devices, and interconnecting piping mounted to a structural steel rack or skid. A properly designed fuel train will include the following, at a minimum:

- At least one manual block valve
- Two automatic block valves in series
- One vent valve between the automatic block valves (gas firing only)
- Flow control valve
- High and low fuel pressure switches
- Two pressure gages, one each at the fuel inlet and outlet

Depending on the custom and operating requirements at a particular plant, pressure regulation, flow measurement devices, and pressure transmitters may also be incorporated. See [Figure 19.13](#) and [Figure 19.14](#) for typical duct burner main fuel system piping arrangements.

19.3.7 DESIGN GUIDELINES AND CODES

19.3.7.1 NFPA 85 (National Fire Protection Association)

First issued for HRSG systems in 1995 as NFPA 8506 and combined into NFPA 85 with other boiler applications in 2000, this standard has become the *de facto* guideline for heat recovery steam generators in the U.S. and in many other countries that have not developed their own national standards. Specific requirements for burner safety systems are included, but as stated in the foreword,

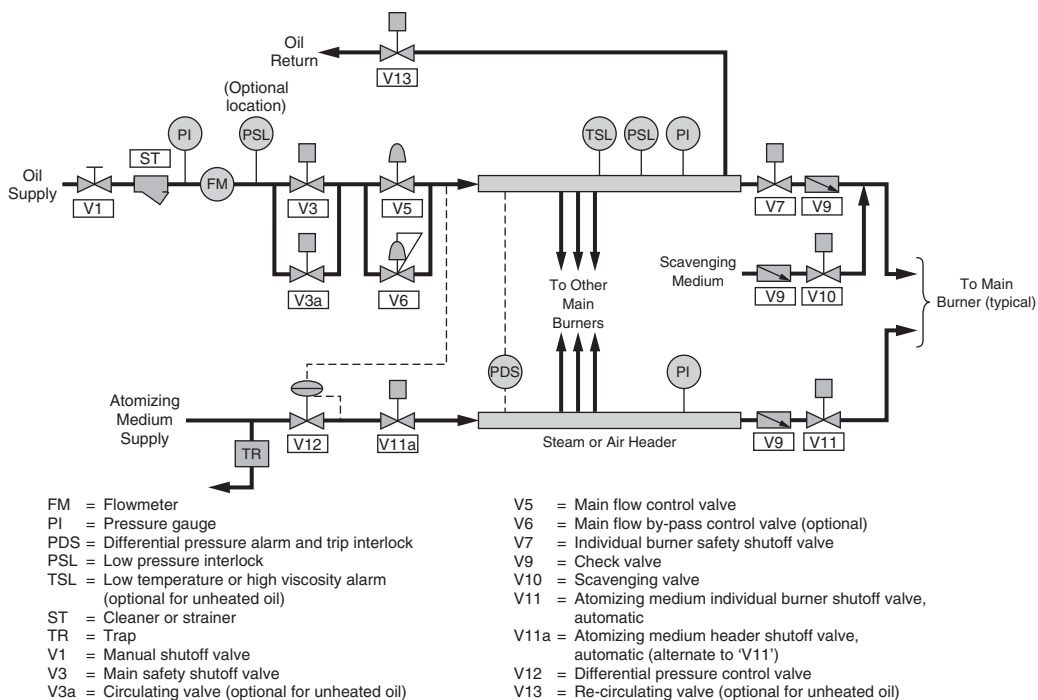


FIGURE 19.14 Typical main oil fuel train: multiple elements.

it does not encompass specific hardware applications, nor should it be considered a “cookbook” for the design of a safe system. Prior to the issuance of HRSG standards, designers often adapted NFPA standards for fired boilers to HRSG systems, which resulted in design inconsistencies.²

19.3.7.2 FM (Factory Mutual)

An insurance underwriter that publishes guidelines on combustion system design, Factory Mutual also “approves” specific components such as valves, pressure switches, and flame safeguard equipment that meet specific design and performance standards. Manufacturers are given permission to display the FM symbol on approved devices. Although FM approval may be required for an entire combustion control system, it is more common for designers to simply specify the use of FM-approved components.

19.3.7.3 UL (Underwriters Laboratories)

Well known in the U.S. for its certification of a broad range of consumer and industrial electrical devices, UL authorizes manufacturers to display their label on specific items that have demonstrated compliance with UL standards. Combustion system designers will frequently require the use of UL-approved components in burner management systems and fuel trains. Approval can also be obtained for custom-designed control systems, although this requirement generally applies only to a few large cities and a few regions in the U.S.

19.3.7.4 ANSI B31.1 and B31.3 (American National Standards Institute)

These codes address piping design and construction. B31.1 is incorporated in the NFPA 85 guideline, while B31.3 is generally used only for applications in refining/petrochemical plants.

19.3.7.5 Others

The following may also apply to duct burner system designs, depending on the country where equipment will be operated:

- National Electrical Code (NEC)
- Canadian Standards Association (CSA) and province requirements (i.e., TSSA)
- International Electrotechnical Commission (IEC)
- European Committee for Electrotechnical Standardization (CENELEC)

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3. Waibel, Richard T. and Somers, Steve, "Retrofitting Duct Burners for CO Control," Paper presented at *American Flame Research Committee*, 1996 meeting.