3.2.1.2
Lean Pre-Mixed Combustion

William R. Bender

Technology & Management
Services, Inc.
Gaithersburg, MD 20879

phone: (301) 670-6390 x144
email: wbender@tms-hq.com

3.2.1.2-1 Introduction

Gas turbine designers are continually challenged to improve cycle efficiency while maintaining or reducing emissions. This challenge is made more difficult by the fact that these are often conflicting goals. The path to improved efficiency is higher working fluid temperatures, but higher temperatures promote NO_x formation and at 2,800 F the threshold for thermal NO_x formation is reached. Furthermore, reducing available oxygen to reduce NO_x can result in higher carbon monoxide (CO) and unburned hydrocarbon emissions due to incomplete combustion. Moreover, increasing firing temperatures above 2,350 F represents a significant materials science challenge.[1]

To achieve lower pollutant emission rates, a variety of pre-formation and post-formation control technologies have been utilized either individually or in combination, including:

- Wet controls (water or steam injection)
- Dry combustion controls (lean combustion, reduced residence time, lean premixed combustion, and two-stage rich/lean combustion)
- Selective catalytic reduction
- SCONOX catalytic absorption
- Catalytic combustion (e.g. Xonon^tm)
- Rich Quench Lean Combustors
- CO oxidation catalysts

This section of the Handbook focuses on Lean Premixed (LPM) combustion, a pre-formation control strategy that has become the standard technique employed by gas turbine original equipment manufacturers (OEM), particularly for natural gas applications.

OEMs have developed processes that use air as a diluent to reduce combustion flame temperatures and reduce NO_x by premixing fuel and air before they enter the combustor. This lean premixed combustion process is referred to by a variety of trade names including General Electric's and Siemens-Westinghouse's Dry Low NO_x (DLN) processes, Rolls-Royce's Dry Low Emissions (DLE) process and Solar Turbines' SoLo NO_x process. When firing natural gas, most of the commercially available systems are guaranteed to reduce NO_x emissions within the 15 to 25 parts per million by volume, dry (ppmvd) range, depending on the OEM, turbine model and application. A few OEM's have guaranteed single digit NO_x emissions.

3.2.1.2-2 Emissions Overview

The primary pollutants emitted by gas turbine engines are NO_x, CO and to a lesser extent, unburned hydrocarbons (UHC). Sulfur dioxide, particulate matter (PM) and trace amounts of hazardous air pollutants may also be present when liquid fuels are fired.

Both CO and UHC are the products of incomplete combustion. Given sufficient time and at high enough temperatures, these two pollutants will be further oxidized to carbon dioxide and water. In the proposed standards of performance for new stationary combustion turbines (40 CFR 60, subpart KKKK, dated February 18, 2005), EPA states, "Turbine manufacturers have significantly reduced CO emissions from combustion turbines by developing lean premix technology. Lean premix combustion design not only produces lower NO_x than diffusion flame technology, but also lowers CO and volatile organic compounds (VOC), due to increased combustion efficiency."[2] The proposed rulemaking concludes that "Stationary combustion turbines do not contribute significantly to ambient CO levels."[3] Accordingly, the primary pollutant of concern from gas turbines continues to be NO_x.

There are two sources of NO_x emissions in the exhaust of a gas turbine. Most of the NO_x is generated by the fixation of atmospheric nitrogen in the flame, which is called thermal NO_x. Thermal NO_x production rates fall sharply as either the combustion temperature decreases, or as the fuel to air ratio decreases. Nitrogen oxides are also generated by the conversion of a fraction of any nitrogen chemically bound in the fuel. Emissions of NO_x from fuel bound nitrogen are insignificant when firing natural gas, but must be considered when firing lower quality distillates and syngas.[4]

3.2.1.2-3 Regulatory Overview

In the late 1970s, EPA established New Source Performance Standards (NSPS) for gas turbines (40CFR60, subpart GG) that limited NO_x emissions from large utility gas turbines to 75 ppmvd (parts per million by volume, dry) when firing natural gas. In the 1980s, with the implementation of Best Available Control Technology (BACT), NO_x emission limitations on gas were reduced to 42 ppmvd. With the implementation of EPA's "top down" BACT strategy, NO_x emissions further decreased to 25 ppmvd. A recent search of EPAs RACT/BACT/LAER Clearinghouse data (years 2000 to 2005) for natural gas-fired combustion turbines greater than 25 MW confirms the trend towards single digit NO_x emissions.

3.2.1.2-4 Combustion Principles

Fuel to Air Ratio

A significant parameter used to characterize combustion is the fuel to air ratio (f/a), expressed either on a volume or mass basis.[5] With precisely enough air to theoretically consume all of the fuel, combustion is referred to as having a "stoichiometric" f/a ratio. Adding more air produces combustion that is fuel-lean, and adding less air produces combustion that is fuel-rich. Because differing fuels have different stoichiometric f/a ratios, it is convenient to normalize the f/a ratio by the stoichiometric value, producing the term equivalence ratio Ø:

$$Ø = \frac{(f/a)actual}{(f/a)stoich} \qquad (1)$$

(Source: note 5 - G.A. Richards, et al, p. 143)

By referring to the equivalence ratio, combustion using different types of fuel is readily described as lean if Ø < 1 or rich if Ø > 1.

Flame Temperature

Another important combustion parameter is the flame temperature. Flame temperatures are determined by a balance of energy between reactants and products. In principal, the highest flame temperatures would be produced at Ø = 1, because all of the fuel and oxygen would be consumed. In practice, the effects of species dissociation and heat capacity shift the peak temperature to slightly above stoichiometric (Ø ~ 1.05).

Fuel type is important in determining the flame temperature. To provide a sense of magnitude, the list below compares calculated adiabatic flame temperatures of two hydrocarbons, CO and H_2. This list applies to stoichiometric combustion in ambient air:

Table 1: Compared adiabatic flame temperature calculations.

Species	Formula	Adiabatic Flame Temperature (K)
Methane	CH_4	2223
Propane	C_3H_8	2261
Carbon Monoxide	CO	2381
Hydrogen	H_2	2370

* Source: note 5 - G.A. Richards, et al, p. 144

It should be noted that the methane flame temperature is approximately 150 K lower than hydrogen and CO. This distinction makes it somewhat easier to produce low-emissions from natural gas, which is mostly methane, compared to syngases containing undiluted H_2 and CO.

3.2.1.2-5 Combustor Designs

Diffusion Flames

The combustion process in a gas turbine can be classified as diffusion flame combustion or lean-premix staged combustion.[6] In diffusion flame combustion, both fuel and oxidizer are supplied to the reaction zone in an unmixed state. The fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high.

At the beginning of gas turbine development, the primary design goal was to optimize performance while complying with applicable emission requirements. Initially, emphasis was placed on maximizing combustion efficiency while minimizing the emission of unburned hydrocarbons and CO. It was possible to fully realize these design goals by providing the diffusion flame with a relatively high combustion chamber volume in which all chemical reactions were allowed to take place completely without the addition of dilution air. To enable the mixing process to occur rapidly and to achieve a uniform temperature in the primary zone, several burners were arranged in a common flame tube. This combustion chamber design yielded optimum thermodynamic properties with low pressure losses and a combustion efficiency of practically 100 percent.

In the early 1970's, when emission controls were introduced, the pollutant of primary concern to regulators shifted to NO_x. For the relatively low levels of NO_x reduction initially required, the injection of water or steam into the combustion zone produced the required reduction in NO_x emissions with minimal performance impact. In addition, the emissions of other pollutants (CO, VOC) did not increase significantly.

To comply with the greater NO_x reduction requirements imposed during the 1980's, further attempts were made to utilize increased quantities of water/steam injection to ensure compliance. These attempts proved detrimental to cycle performance and part lives, and the emission rates for other pollutants also began to rise significantly. Other control methodologies needed to be developed, which led to the introduction of the LPM combustor.

Lean Premixed (LPM) Combustion

The Gas Turbine Association defines Lean Premix Stationary Combustion Turbine as "Lean premixed stationary combustion turbine means any stationary combustion turbine designed to operate at base load with the air and fuel thoroughly mixed to form a lean mixture before delivery to the combustor.[7] Mixing may occur before or in the combustion chamber. A lean premixed turbine may operate in diffusion flame mode during operating conditions such as startup and shutdown, low or transient loads and cold ambient."[8] Premixing prevents local "hot spots" within the combustor volume that can lead to significant NO_x formation.

In LPM systems, atmospheric nitrogen (from the combustion air) acts as a diluent, as fuel is mixed with air upstream of the combustor at deliberately fuel-lean conditions. The f/a ratio typically approaches one-half of the ideal stoichiometric level, meaning that approximately twice as much air is supplied as is actually needed to burn the fuel. This excess air is a key to limiting NO_x formation, as very lean conditions cannot produce the high temperatures that create thermal NO_x.

Design of a successful LPM combustor requires the development of hardware features and operational methods that simultaneously allow the equivalence ratio and residence time in the flame zone to be low enough to achieve low NO_x emissions, but with acceptable levels of combustion dynamics, stability at part-load conditions and sufficient residence time for CO burnout.[9]

In principle, the LPM strategy is quite simple: keep the combustion process lean at all operating conditions. In practice, this is not easily achieved. If the engine is already near the limit of lean operation at full power, it is not possible to reduce the combustor temperature rise on all of the fuel injectors, because the flame will be extinguished. To solve this problem, some of the fuel or air must be rerouted (or staged) to keep the flame within its operating boundaries. Typically, engine designers use either fuel or air staging to accomplish this goal. Fuel staging can be accomplished either radially or axially. Examples of radial staging include the use of pilot flames or reducing/eliminating fuel from some injectors completely. Axial staging injects fuel at two places along the combustion gas flowpath. Products from the first combustion zone are mixed with fuel and air in a subsequent combustion zone, providing an advantage for lean operation of the second zone. Finally, some engine designs use air staging (also known as variable geometry) to accomplish the goal of maintaining low flame temperatures. This approach can maintain the desired combustion zone temperature at all operating conditions, but adds the complexity of controlling the large volume flow of combustion air.

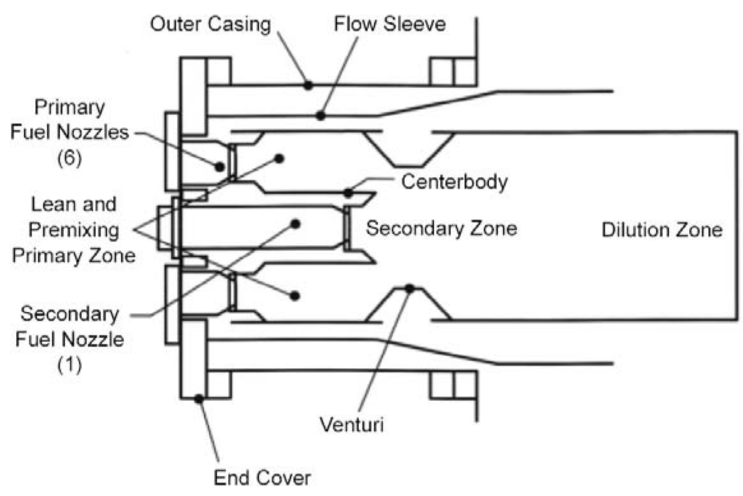

Fig. 1. Dry Low NO_x Combustor

Source: note 6, Davis & Black, p. 3, Figure 5.

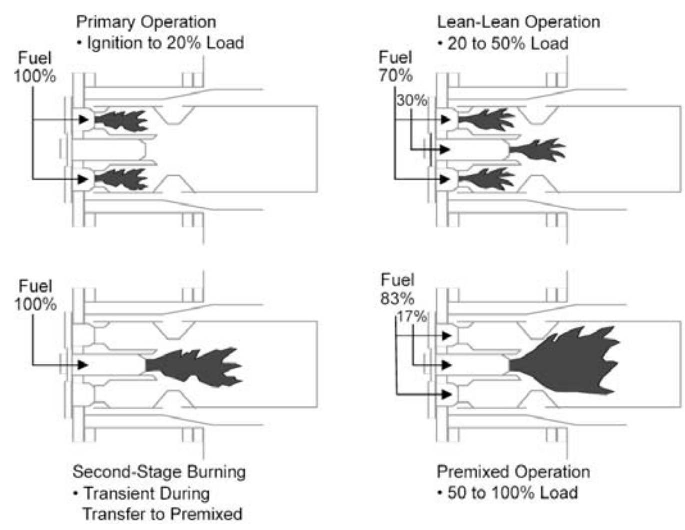

Fig. 2. Fuel-Staged Dry Low NO_x Operating Modes

Source: note 6, Davis & Black, p.4, Figure 6.

GEs Dry Low NO_x system, as described in note 7 (L.B. Davis), has been selected to illustrate the evolution and operation of a LPM staged combustion system in response to regulatory changes and efficiency upgrades. The GE Dry Low NO_x (DLN-1) combustor shown in figure 1 is a two-stage premixed combustor designed for use with natural gas and capable of operation on liquid fuel.

As shown, the combustion system includes four major components: fuel injector system, liner, venture, and cap/centerbody assembly. These components form two stages in the combustor. In the premixed mode, the first stage thoroughly mixes the fuel and air and delivers a uniform, lean, unburned fuel-air mixture to the second stage. The DLN-1 system operates in four distinct modes, illustrated in figure 2:

Modes of Operation for the DLN-1 system

- Primary – Fuel to the primary nozzles only. Flame is in the primary stage only. This mode of operation is used to ignite, accelerate, and operate the machine over low- to mid-loads, up to a preselected combustion reference temperature.
- Lean-Lean – Fuel to both the primary and secondary nozzles. Flame is in both the primary and secondary stages. This mode of operation is used for intermediate loads between two pre-selected combustion reference temperatures.
- Secondary – Fuel to the secondary nozzle only. Flame is in the secondary zone only. This mode is a transition state between lean-lean and premix modes. This mode is necessary to extinguish the flame in the primary zone, before fuel is reintroduced into what becomes the primary premixing zone.
- Premix – Fuel to both primary and secondary nozzles. Flame is in the secondary stage only. This mode of operation is achieved at and near the combustion reference temperature design point. Optimum emissions are generated in premix mode.

At loads less than 20 percent of baseload, NO_x and CO emissions from the DLN-1 were similar to those from standard (diffusion) combustion systems.

Other OEM's offer similar systems, with the notable exception being Alstom. Alstom's sequential combustion DLN technology was developed originally by ABB for the GT24 and GT26 gas turbines. Combustion takes place in the primary DLN combustor (EV^tm^) followed by fuel addition in a second (SEV^tm^) combustion chamber located aft of the first row of turbine blades. This DLN technology was commercialized in 1997 and applies the thermodynamic reheat principal. The sequential combustion provides low NO_x emissions due to the fact that the SEV^tm^ combustor does not contribute to NO_x production.[10]

The OEM's continually strive to improve performance while complying with increasingly restrictive emissions requirements. As F-technology gas turbines became available in the late 1980s with their higher firing temperatures, the OEMs were forced to redesign their DLN systems to maintain emissions at acceptable levels (~25ppmvd). Studies conducted by GE concluded that air usage in the combustor other than for mixing with fuel would have to be strictly limited. A design that repackaged DLN-1 premixing technology but eliminated the venture and centerbody assemblies that required cooling air was implemented and called DLN-2. The DLN-2 combustion system is a single-stage dual-mode combustor that can operate on both gaseous and liquid fuels. On gas, the combustor operates in a diffusion mode at low loads (< 50 percent load) and in a premixed mode at higher loads. Oil operation on the DLN-2 combustor is in the diffusion mode across the entire load range, with diluent injection used for NO_x control. The DLN-2 combustor system has a single burning zone formed by the liner and the cap face. In low emissions operation, 90 percent of the gas fuel is injected through radial gas injection spokes in the premixer, and combustion air is mixed with the fuel in tubes surrounding each of the five fuel nozzles. The premixer tubes are part of the cap assembly. The fuel and air are thoroughly mixed, flow out of the five tubes at high velocity and enter the burning zone, where lean, low NO_x combustion occurs. The vortex breakdown from the swirling flow exiting the premixers, along with the sudden expansion in the liner, are mechanisms for flame stabilization.

In the early 1990s, continued regulatory pressures led the OEMs to develop 9 ppm combustion systems. During this time, GE introduced the DLN-2.6 combustor for the Frame 7FA machine which allowed for approximately 6 percent additional air to pass through the premixers in the combustor. The change in air splits was accomplished through reductions in cap and liner cooling air flows, requiring increased cooling effectiveness. A key feature of the DLN-2.6 combustor was the addition of a sixth burner, located in the center of the five DLN-2 burners. By fueling the center nozzle separately from the outer nozzles, the f/a ratio could be modulated relative to the outer nozzles. Another key feature of the DLN-2.6 combustor was the elimination of the diffusion mode, which required additional loading and unloading strategies.

GE's H system^tm^ combustor called DLN-2.5 uses a simplified combustion mode staging scheme to achieve low emissions over the premixed load range. The most significant feature associated with this variant is that there are only three combustion modes: diffusion, piloted premix, and full premix.[11]

The modifications required to reduce the emissions from the Siemens Westinghouse 15 ppm DLN combustor to 9 ppm are predominately the use of a premixed pilot and support housing design changes.[12]

3.2.1.2-6 LPM Technological Challenges

CO/NO_x Tradeoff

Since the optimum flame temperature of a LPM combustor is designed to be near the lean flammability limit, LPM combustor performance is characterized by a CO/ NO_x tradeoff (figure 3).[13] At the combustor design point, both CO and NO_x are below target levels; however, deviations from the design point flame temperature cause emissions to increase. A reduction in temperature tends to increase CO emissions due to incomplete combustion. Conversely, an increase in temperature will increase thermal NO_x formation.

The CO/NO_x trade-off must be addressed during part-load operation when the combustor is required to run at an even leaner condition overall. The tradeoff also comes into play in development efforts to reduce LPM combustor NO_x emissions by further reducing the primary zone design point temperature.

Cold Ambient Temperatures

Below an OEM's specified ambient temperature threshold (0 F or -20 F), emission rate warranties are generally not offered. LPM turbines have demonstrated reliable operation below the ambient temperature warranty level, but the impact on the emissions signature is not well documented. Emissions below the threshold can be impacted by specific engine control adjustments needed to maintain combustion stability and prevent oscillations. The most commonly deployed control system is to increase the pilot fuel level, which increases NO_x and CO emissions.

As a solution to extending the ambient temperature warranty range, OEMs are collecting cold ambient data in an effort to improve designs. In the interim, many OEMs offer the option to incorporate an inlet air heating system as part of the design package.

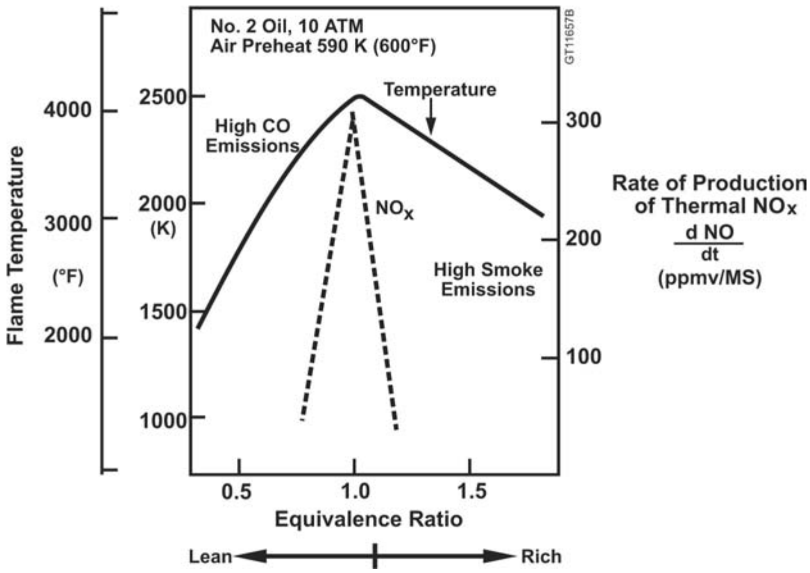

Fig. 3. NO_x Production Rate

Source: note 4, Pavri & Moore, p. 17, Figure 20.

Low and Transient Load Operation

Low load or transient load events can affect the emissions performance of LPM gas turbines because of engine controls required to prevent combustor flameout. To prevent the formation of NO_x, LPM combustors are designed to operate close to engine flameout temperatures when compared to conventional combustors. When load is reduced to a low level or increased/decreased rapidly, it is necessary to augment combustor flame stability to prevent flameout. Most OEMs augment combustor flame stability through a fuel distribution adjustment such as the addition of pilot fuel. The addition of pilot fuel creates a diffusion flame, which increases NO_x, CO, and VOC emissions.

When operating at sustained low load conditions, CO emissions may increase significantly as a result of incomplete combustion. Due to the lower temperatures in a LPM combustor at low loads and the introduction of pilot fuel, a rich stoichiometric fuel mixture results accompanied by incomplete combustion.

3.2.1.2-7 LPM Future Developments

Manufacturers continue to develop LPM gas turbine combustion as the preferred approach to meet future emission requirements.[14] From a life cycle cost perspective, preventing pollutant formation has been shown to be more cost effective than the use of post-combustion techniques. Work is in progress using the latest experimental and analytical tools to improve emissions and operating flexibility of LPM systems.

Combustor Liner

LPM combustor liner cooling methods can have a significant effect on emissions. The current generation of LPM combustors employs a variety of liner cooling methods including film cooling (louver or effusion) and backside cooling. Many first generation LPM turbines use film cooling to maintain acceptably low combustor wall temperatures, but many manufacturers have or will make the transition to backside-cooled technology with their next generation of LPM turbines.

Backside-cooled liners have been in use for some commercial products for several years. Compared to film cooling, backside cooled liners forego cooling air injection completely. Instead, combustor wall temperatures are controlled solely through convective cooling by a high velocity airstream on the cold side of the liner. In most instances, the high heat flux from the flame requires augmenting the backside convective process to keep the liner wall temperatures from becoming excessive. Turbulators in the form of trip strips, fins, and pins act to increase the cooling flow turbulence at the liner wall and augment the heat removal process. Those OEMs already utilizing backside cooling will optimize its design in order to warranty lower NO_x levels.

Fuel Injectors

Incorporating LPM combustion into gas turbines also required significant change to the fuel injectors. LPM fuel injectors are significantly larger than conventional injectors due to the higher air flow through the injector swirlers and the required volume of the premixing chamber used to mix fuel and air. Both axial and radial swirlers have been used by the OEM's to swirl the premix air. Fuel is injected either through the swirler vanes or fuel spokes. Most LPM fuel injector designs include a pilot fuel injection point. A pilot flame is used to stabilize engine operation during load transients and low load operation.

Fuel injectors are being optimized to improve f/a mixing and reduce local hot spots while improving flame stability. Achieving an optimum f/a temperature profile exiting the injector is essential. Design modifications to the fuel injection points and the air swirler are being investigated both computationally and experimentally.

Combustor Air Management

Several combustor air management systems have been employed in LPM combustion systems to avoid combustor flameout and expand the low emissions operating range. Each technique ultimately provides control of the primary zone airflow to maintain the primary zone f/a ratio near its optimum low emissions level during part-load operation.

Casing air bleed

Some two-shaft gas turbines used for gas compression and mechanical drive bleed air from the combustor casing at part load. The case bleed method of variable geometry has proven effective in controlling CO emissions. A consequence of air bleed, however, is deterioration in engine part-load thermal efficiency, since compressed bleed air no longer enters the turbine section of the engine to produce power.

Inlet guide vanes

Some gas turbines used for power generation maintain optimum primary zone f/a ratios by modulating the compressor inlet guide vanes (IGV). Closing the IGVs reduces the airflow through the engine compressor and combustor. Regulating IGVs for single-shaft engines to control combustor airflow has a very small reduction in part-load thermal efficiency.

Combustor/Injector staging

To enhance stability, some LPM turbines use fuel injection in multiple axial stages, with airflow to the additional stages being variable. Other LPM designs use multiple injector heads fired as a function of load.

Control Systems

The control system for LPM engines modulates the air and fuel management systems to keep the combustion primary zone temperature within a specified range while maintaining acceptable engine turn-down and low-load operating stability. Accurate control of the primary zone temperature is critical to controlling NO_x and CO emissions, which is typically accomplished through power turbine inlet temperature as an indirect measurement of the combustor exit or turbine inlet temperature.

3.2.1.2-8 Dual Fuel Operation

Many gas turbine installations require operation on both gaseous and liquid fuels without affecting operability or environmental performance.[15] Liquid fuels are more difficult to mix and pose difficulties in achieving homogeneous f/a mixture distribution that is required for low- NO_x combustion.

Testing has shown that the pre-mixer enabled comparable environmental performance with both natural gas and No. 2 diesel fuel at representative temperatures and pressures.

3.2.1.2-9 Fuel Variability Concerns

The Advanced Turbine Systems (ATS) program has produced significant advances in combustion technology.[16] Careful development of premix systems allows state-of-the-art combustors to operate with NO_x levels approaching single digit performance. Although this progress is notable, reliable attainment of ultra-low emissions is contingent upon tight control of manufactured components, engine operating parameters, and fuel specifications. Failure to operate a premix combustor within planned specifications can lead to problems that range failure to meet emissions targets to hardware failure caused by flashback or oscillating dynamics. This sensitive behavior presents a challenge for expanded deployment of low-emission combustors that have been optimized almost exclusively for operation on natural gas fuel. The desire to operate such combustors on various fuels or in unique engine cycles (e.g., highly humidified cycles, biomass gasification combined cycles) poses a new set of constraints for low-emission operation.

Hydrogen

Pathways to “zero” emissions power plants include the utilization of hydrogen directly as a fuel. Because of its high combustion temperature, the development of hydrogen-fueled turbines with comparable performance to natural gas is problematic. Stable, efficient, low- NO_x combustion requires rapid, homogeneous mixing of fuel and air, which is a challenge when firing natural gas and made far more difficult with highly reactive hydrogen.

Medium Heating Value Fuel

A common source for medium heating value fuel (200 to 800 Btu/scf) is oxygen-blown gasification of coal or residual oil. Because these gases are “manufactured” from other fuels, they are commonly referred to as synthesis gas, or syngas fuels and typically contain significant quantities of H_2 and CO. Compared to natural gas, the stoichiometry of these gas mixtures requires a smaller volume of air for complete combustion, producing higher flame temperatures. As a further complication, H_2 has a very high flame speed and very short ignition delay. Thus it is very difficult to avoid flashback or autoignition in a premixed burner. The standard approach to premixing is unlikely to work for these fuels.

Low Heating Value Fuel

For gas turbines, the usual source of low heating-value fuel (~200 Btu/scf) is air-blown gasification of coal or biomass gasification. A significant feature of low-heating value fuels is that they often contain ammonia which can greatly complicate NO_x reduction. Because of the high dilution level, these fuels have lower flame temperatures and lower flame speeds than natural gas or medium heating-value fuels. From the standpoint of thermal NO_x emissions, this is an advantage. Because the volume of fuel flow is so great, the combustor aerodynamics are significantly affected and must be re-designed. This may impact low-emission backup operation on conventional fuels. CO oxidation is also a concern.

3.2.1.2-10 Background Information

Regulatory Overview

Clean Air Act

Congress enacted the Clean Air Act (CAA) in 1970 to address growing concerns over the nation’s air quality.[17] As a result of the Act, national ambient air quality standards (NAAQS) were established for criteria pollutants. Areas of the country that exceed the NAAQS are considered “non-attainment for that pollutant. The U.S. regulatory structure imposes more stringent air pollution control programs in non-attainment areas. The CAA is a Federal law covering the entire country; however, States and local governments are allowed to develop and implement more stringent air pollution rules than those mandated by the CAA. The CAA also established New Source Performance Standards (NSPS) for a variety of potential emissions sources, including gas turbines.

NSPS

Emissions control requirements for oxides of nitrogen were first applied to gas turbines by the Los Angeles County Air Pollution Control District (LAAPCD) and the San Diego Air Pollution Control District (SDAPCD) in the early 1970’s. To comply with these regulations, water was injected into the combustor flame zone to reduce flame temperature. The consequent reduction in NO_x amounted to about 40 percent when half as much water as fuel was injected into the reaction zone. The emission level achieved was approximately 75 ppmvd (parts per million by volume, dry) on oil.

These results and other data were used by the U.S. EPA to develop New Source Performance Standards that went into effect in September 1979. The details of this NSPS are presented in 40CRF60 Subpart GG. Turbines with heat input over 10 million Btu/hr, generating less than 30 MW electrical output, and supplying less than one-third of their electrical output to an electric utility, are required to meet a NO_x emission standard of 150 ppm, corrected for efficiency. Emergency turbines are exempt from this standard, as are certain other types of turbines. Electric utility turbines with a heat input above 100 million Btu/hr must comply with a NO_x standard of 75 ppm, corrected for efficiency. Most turbines available today can achieve NO_x emissions of 25 to 42 ppm or less without post-combustion controls. Thus, the existing NSPS is not typically a controlling regulation for gas turbines.

In July 2004, EPA updated the NSPS for gas turbines in a direct final ruling. Most notably, the revised standards require new LPM turbines that commence construction after July 8, 2004 to use a NO_x continuous emissions monitoring system (CEMS) or, owners can continuously monitor engine parameters that indicate when the turbine is out of LPM combustion mode.

On February 18, 2005, EPA proposed standards of performance for new stationary gas turbines in 40CFR60, subpart KKKK. The new standards would reflect changes in NO_x emissions control technologies and turbine design and are intended to bring the emission limits up to date with the performance of current combustion turbines.

New Source Review

In addition to AAQS, the CAA established an air permitting program called New Source Review (NSR). NSR is divided into two primary programs: Prevention of Significant Deterioration (PSD) and Non-Attainment NSR. Each program applies to “major sources” and “major modifications,” but in non-attainment NSR, a source can be considered “major” at much lower thresholds.

Best Available Control Technology (BACT)

If a source triggers PSD review, then the owner must identify the appropriate level of emissions controls for pollutants that exceed specific thresholds. In attainment areas, the standard for evaluation is Best Available Control Technology (BACT). A BACT determination establishes an achievable emissions limitation taking into account the energy, environmental and economic impacts of applying the pollution control technology necessary to meet that limitation. EPA now requires that a "top-down" BACT analysis be followed for all PSD permit applications.[18]

As a result of its structure, BACT is a "living" standard, which becomes more stringent over time as new, more efficient, and lower cost control technologies become available. BACT for a specific application can only be defined in the context of current demonstrated technology and for a specific application. Because BACT determinations are site-specific, generic BACT requirements do not exist; however, there have been recent BACT NO_x determinations as low as 2 to 5 ppm for gas turbines greater than 25MW.

A recent search of EPAs RACT/BACT/LAER Clearinghouse data (years 2000 to 2005) for natural gas-fired combustion turbines greater than 25 MWs has resulted in the following NO_x emission limits:

Table 2: NO_x emission limits.

Number of Permits	NO_x Emission Limit (ppm)
37	<9.0
51	9.0
106	<15.0
11	15.0
117	<25.0
10	25.0
5	>25.0

This table confirms the trend towards single digit NO_x emissions. For certain gas turbines, NO_x emission rates $\geq$ 9 ppm can be met using LPM combustors. Permit limits less than 9 ppm require the application of post combustion controls.

Lowest Achievable Emission Rate (LAER)

Major sources/modifications in non-attainment areas are subject to a determination of LAER. LAER is defined as the most stringent emission limitation achieved in practice for the class or source category. The primary difference between BACT and LAER is that LAER does not allow economic impacts to be considered when evaluating pollution control technologies leading to an emissions limitation.

Other Regulatory Programs

Other regulatory programs that could potentially impact gas turbine emissions include the Clean Air Interstate Rule, the President' s Clear Skies Initiative, and Maximum Available Control Technology (MACT) standards.[19]

3.2.1.2-11 Nitrogen Oxide Formation

Tropospheric ozone has been and continues to be a significant air pollution problem in the U.S. and is the primary constituent of smog.[20] Large portions of the country do not meet the ozone National Ambient Air Quality Standard (NAAQS) and thereby expose large segments of the population to unhealthy levels of ozone in the air. NO_2 reacts in the presence of air and ultraviolet light (UV) in sunlight to form ozone and nitric oxide (NO). The NO then reacts with free radicals in the atmosphere, which are also created by the UV acting on volatile organic compounds (VOC). The free radicals then recycle NO to NO_2. In this way, each molecule of NO can produce ozone multiple times. This may continue four or five times until the VOCs are reduced to short chains of carbon compounds that cease to be photo-reactive.

In addition to the NO_2 and ozone concerns, NO_x and sulfur oxides (SO_x) in the atmosphere are captured by moisture to form acid rain. Acid rain impacts certain ecosystems and some segments of our economy. All of these facts indicate the need to reduce NO_x emissions, but to do so requires an understanding of the generation and control mechanisms.

According to the Zeldovich equations, NO is generated to the limit of available oxygen (about 200,000 ppm) in air at temperatures above 1300C (2370F). At temperatures below 760C (1,400F), NO is either generated in much lower concentrations or not at all.

There are two mechanisms by which NO_x is formed in gas turbine combustors:

1. The oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x), and
2. The conversion of nitrogen chemically bound in the fuel (fuel NO_x).

Thermal NO_x

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form NO_x. Prompt NO_x, a form of thermal NO_x, is formed in the proximity of the flame front as intermediate combustion products such as HCN, N and NH that are oxidized to form NO_x. Prompt NO_x is formed in both fuel-rich flames zones and dry low NO_x (DLN) combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is a significant percentage of overall thermal NO_x emissions in DLN combustors. For this reason, prompt NO_x becomes an important consideration for DLN combustor designs, establishing a minimum NO_x level attainable in lean mixtures.

The chemical mechanisms that produce NO_x are listed below. These reactions represent the major pathways for NO_x formation; see Nicol et al. for a more detailed description of the chemical pathways.[21] Various authors have used different names for these pathways, or include different reactions. This is a result of advances in understanding the relative importance of these mechanisms. For example, until recently, the nitrous oxide path was simply included as an extension of the prompt mechanism[22], but has emerged as an important chemical path in lean burning gas turbines and is now referred to as a distinct mechanism:

Extended Zeldovich mechanism:

(1) $O + N_2 \leftrightarrow NO + N$
(2) $N + O_2 \leftrightarrow NO + O$
(3) $N + OH \leftrightarrow NO + H$

Nitrous oxide:

(4) $N_2 + O + M \leftrightarrow N_2O + M$
(5) $N_2O + O \leftrightarrow NO + NO$
(6) $N_2O + H \leftrightarrow NO + NH$

Prompt:

(7) $N_2 + CH \leftrightarrow HCN + N$

The prompt mechanism is followed by a sequence of reactions converting HCN to NO; reaction (7) is just the initiation. The detailed sequence was reported by Fenimore, and the prompt mechanism is sometimes referred to as "Fenimore-prompt" or just "Fenimore".[23] The CH reaction is also important for fuels containing nitrogen which can directly form the HCN species.

The extended Zeldovich mechanism is also known as the thermal mechanism when O and H species are at equilibrium levels. The thermal route is a primary mechanism for NO_x when flame temperatures are above approximately 1800K (2780F). Below this temperature, the thermal reactions are relatively slow. Thus, a common approach to NO_x control is to reduce the combustion temperature so that very little thermal NO_x can form.

In the absence of thermal NO_x, the other mechanisms become significant. Non-equilibrium concentration of O or H atoms in the flame region can produce NO_x via reactions (1) to (3), and this is known as Zeldovich NO_x. The nitrous oxide path depends on the intermediate species N_2O which itself is generated by O-atom attack of nitrogen.

Fuel NO_x

Fuel NO_x is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some kinds of natural gas, does not contribute significantly to fuel NO_x formation. Some low-Btu synthetic fuels contain nitrogen in the form of ammonia (NH_3). Other low-Btu fuels such as sewage and process waste-stream gases also contain nitrogen. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x. With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. The fraction of fuel-bound nitrogen (FBN) converted to fuel NO_x decreases with increasing nitrogen content, although the absolute magnitude of fuel NO_x increases. For example, a fuel with 0.01 percent nitrogen may have 100 percent of its FBN converted to fuel NO_x, whereas a fuel with a 1.0 percent FBN may have only a 40 percent conversion rate. Natural gas typically contains little or no FBN. As a result, when compared to thermal NO_x, fuel NO_x is not a major contributor to overall NO_x emissions from stationary gas turbines firing natural gas.

3.2.1.2-12 Conclusions

OEMs continue to improve LPM technology; simultaneously, regulators continue to lower emissions requirements.[24] R&D efforts continue to advance technology and provide valuable contributions to design and manufacturing techniques to further enhance performance while reducing emissions and overall plant costs.

Leveraging advances made in natural gas-fueled turbines through the ATS Program is critical to achieving performance goals established for future coal-based systems, especially Integrated Gasification Combined Cycle (IGCC) plants and FutureGen. Gas turbines utilized in IGCC plants operate on syngas derived from gasification. Syngas typically contributes 15 to 20 percent to the volumetric flow through an advanced gas turbine to achieve the same heat input as natural gas. The additional mass flow theoretically increases gas turbine power output by 30 to 40 percent. However, aerodynamic issues currently limit power gains to values lower than those theoretically possible.

DOEs Fossil Energy Turbine Technology R&D Program being implemented by NETL was recently expanded with the selection of ten new projects valued at $130 million. The new program will advance turbines and turbine subsystems for integrated gasification combined cycle (IGCC) power plants and address the use of hydrogen and syngas.

3.2.1.2-13 Notes

1. U.S. Department of Energy Office of Fossil Energy, NETL, Turbine Program, "Enabling Near-Zero Emission Coal-Based Power Generation," October 2005.
2. Federal Register: February 18, 2005 (Volume 70, Number 33), pages 8314 – 8332.
3. Ibid.
4. R.Pavri and G.D. Moore, GE Power Systems, Gas Turbine Emissions and Control, GER-4211, 03/01
5. G.A. Richards, M.M. McMillan, R.S. Gemmen, W.A. Rogers, and S.R. Cully, "Issues for Low-emission, Fuel-flexible Power Systems" (U.S. Department of Energy); A. Biro, "Effect of flame-temperature on NO_x emission during natural gas firing," (Hungarian Academy of Sciences, 1998).
6. L.B. Davis and S.H. Black, "Dry Low NO_x Combustion Systems for GE Heavy-Duty Gas Turbines," GER-3568G: GE Power Systems, October 2000; R. Eldrid, L. Kaufman, and P. Marks, "The 7FB: The Next Evolution of the Gas Turbine," GER-4194: GE Power Systems April 2001; R.D. Brdar and R.M. Jones, "GE IGCC Technology and Experience with Advanced Gas Turbines," GER-4207: GE Power Systems, October 2000; F.J. Brooks, "GE Gas Turbine Performance Characteristics," GER-3567H: GE Power Systems, October 2000; L.B. Davis, "Dry Low NO_x Combustion for GE Heavy Duty Gas Turbines," GER-3568A: GE Power Generation, 1983.
7. See note 4 (Pavri & Moore) and (Davis); also see note 5 (Richards and others).
8. B. Rising, letter to U.S. EPA, February 2005.
9. See note 6 (Davis & Black, 2000).
10. Alstom Power, Sequential Combustion, http://www.power.alstom.com/home/equipment_systems/turbine/gas_turbines/GT24_andGT26__188MW_and_281MW.html.
11. R.K. Matta, G.D. Mercer, and R.S. Tuthill, "Power Systems for the 21st Century – "H" Gas Turbine Combined-Cycles," (GE Power Systems, October 2000).
12. R. Bland, et al, "Siemens W501F Gas Turbine: Ultra Low NO_x Combustion System Development," (Siemens Westinghouse Power Corporation, 2004).
13. G. A. Richards, K.H. Casleton, D. J. Maloney, and R.S. Gemmen, "Federal Energy Technology Center, Addressing the Challenge of Low-Emission Combustion" (Department of Energy); also see notes 4 (Pavri & Moore) and (Davis) and note 5.
14. See notes 5 and 13.
15. See note 6 (Brdar & Jones) and (Davis); also see notes 5 and 13.
16. U.S. Department of Energy, Office of Fossil Energy, NETL, Advanced Turbine Systems, Advancing the Gas Turbine Power Industry; also see notes 2, 5 and 13.
17. U.S. Environmental Protection Agency, Office of Air Quality, Technical Bulletin EPA 456/F-pp-006R, "Nitrogen Oxides (NO_x): Why and How They Are Controlled," November 1999; U.S. Environmental Protection Agency, Office of Air Quality, *AP 42*, 5th ed. Compilation of Air Pollutant Emission Factors Vol.1: Stationary Point and Area Sources, Sec. 3.1; U.S. Environmental Protection Agency, Office of Air Quality, Technology Transfer Network, Clean Air Technology Center, RACT/BACT/LAER Clearinghouse; Energy and Environmental Analysis, Inc., Database on State Permitting Issues –Air Regulations (http://www.eea-inc.com/rrdb/DGRegProject/RegBack.html); N.H. Hydari, A.A. Yousuf, H.M. Ellis "Comparison of the Most Recent BACT/LAER Determinations for Combustion Turbines by State Air Pollution Control Agencies, June 2002; California Environmental Protection Agency, Air Resources Board, Report to the Legislature, Gas-Fired Power Plant NO_x Emission Controls and Related Environmental Impacts, May 2004; ONSITE SYCOM Energy Corp., Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines, 11/05/99.
18. J. Calcagni, U.S. Environmental Protection Agency, Memorandum dated June 13, 1989, Transmittal of Background Statement on "Top Down" BACT.
19. A. Jones, L. Witherspoon, and L. Cowell, Solar Turbines, Inc., Meeting Regulatory Challenges Through Advances in Gas Turbine Emission Control, 2004.
20. See note 7 (Davis & Black), (Pavri & Moore) and (Davis); also see note 17 (EPA Tech Bulletin, Nov. 1999), (CA EPA), and (ONSITE Sycom); note 19.
21. D.G. Nicol, R.C. Steele, N.M. Marinov, and P.C. Malte, "The importance of the nitrous oxide pathway to NO_x in lean premixed combustion" *ASME Journal of Engineering for Gas Turbines and Power* :1995.
22. C.T. Bowman, "Control of combustion generated nitrogen oxide emissions: technology driven by regulations" (Twenty-Fourth Symposium on Combustion, The Combustion Institute, Pittsburgh, PA 1992).
23. C.P. Fenimore, "Formation of nitric oxide in premixed hydrocarbon flames," (The Thirteenth Symposium (International) on Combustion, The Combustion Institute, Pittsburgh, PA 1971).
24. See notes 1 and 16.

BIOGRAPHY

3.2.1.2 Lean Pre-Mixed Combustion

William R. Bender

Technology & Management Services, Inc.
Gaithersburg, MD 20879

phone: (301) 670-6390 x144
email: wbender@tms-hq.com

William R. Bender is a Senior Associate with Technology & Management Services, Inc. (TMS). Mr. Bender has over 34 years of experience with gas turbine power systems as a Project Construction Manager, Project Manager, and Project Engineer. While with a large A/E, he was a Project Engineer on Florida Power & Light's Martin combined cycle Project and Tampa Electric's Polk Power Station. As a TMS employee, Mr. Bender is responsible for the planning and analyzing of fossil energy systems, policy initiatives and research, development and deployment programs in support of DOE Headquarters and NETL. His areas of expertise include coal, oil and gas power systems; technology and economic evaluation and assessments; energy and environmental policy analysis and multi-task project management.