Presented at the Renewable Energy World Conference & Expo
March 10 – 12, 2009, Las Vegas, NV.

Dispatchable Renewable Energy: Gas Turbines Can Burn Liquid Biofuels as Cleanly as Natural Gas

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Abstract

A Lean, Premixed, Prevaporized (LPP) combustion technology has been developed that converts liquid biofuels, such as ethanol or biodiesel, into a substitute for natural gas, called LPP Gas™. This LPP Gas™ can then be burned with low emissions in virtually any combustion device in place of natural gas, providing users substantial fuel flexibility. A gas turbine utilizing LPP combustion technology to burn biofuels creates a "dispatchable" (on-demand) renewable power generator with low criteria pollutant emissions and no net carbon emissions.

Biodiesel and ethanol were tested in an atmospheric pressure test rig utilizing commercial gas turbine combustor hardware (designed for natural gas) and achieved natural gas level emissions. Both biodiesel and ethanol achieved natural gas level emissions for NO_x, CO, SO_x and particulate matter (PM). Extended lean operation was observed for biodiesel due to the wider lean flammability range for this long chain hydrocarbon fuel compared to natural gas.

Performance calculations have shown that for a typical combined cycle power plant, one can expect to achieve a two percent (2%) improvement in the overall net plant heat rate when burning liquid fuel as LPP Gas™ as compared to burning the same liquid fuel in traditional spray-flame diffusion combustors with water injection. This level of heat rate improvement is quite substantial, and represents an annual fuel savings of over $2.5 million dollars alone for base load operation of a GE Frame 7EA combined cycle plant (126 MW) using biodiesel.

This technology enables a clean and reliable form of renewable energy generation using liquid biofuels that can be a primary source for power generation or be a back-up source for inconsistent renewable energy sources such as wind and solar. The LPP technology allows for the cleanest use of biofuels in combustion devices without water injection or the use of post-combustion pollution control equipment and can easily be incorporated into both new and existing gas turbine power plants. No changes are required to the DLE gas turbine combustor hardware.

Renewable Energy

Today, more than half of the states in the US have enacted renewable portfolio standards (RPS) or goals that require a specified percentage of generated electrical power come from renewable energy sources (Figure 1, [1]). These sources can include wind, solar, geothermal, biomass, biofuels and falling water (small scale hydro-power). Using biofuels in a gas turbine with the LPP System creates a clean burning dispatchable renewable energy generator that is more reliable than solar or wind power technology and can help states meet their RPS mandates by providing renewable energy on demand. Unlike today's wind and solar farms, the LPP System can use existing powerplant infrastructure including the generation assets (i.e. gas turbines) and the power grid (transmission assets) to create a clean and low cost solution for the generation of renewable power on demand. The LPP System can be used on new gas turbines or can be easily added to existing turbines.

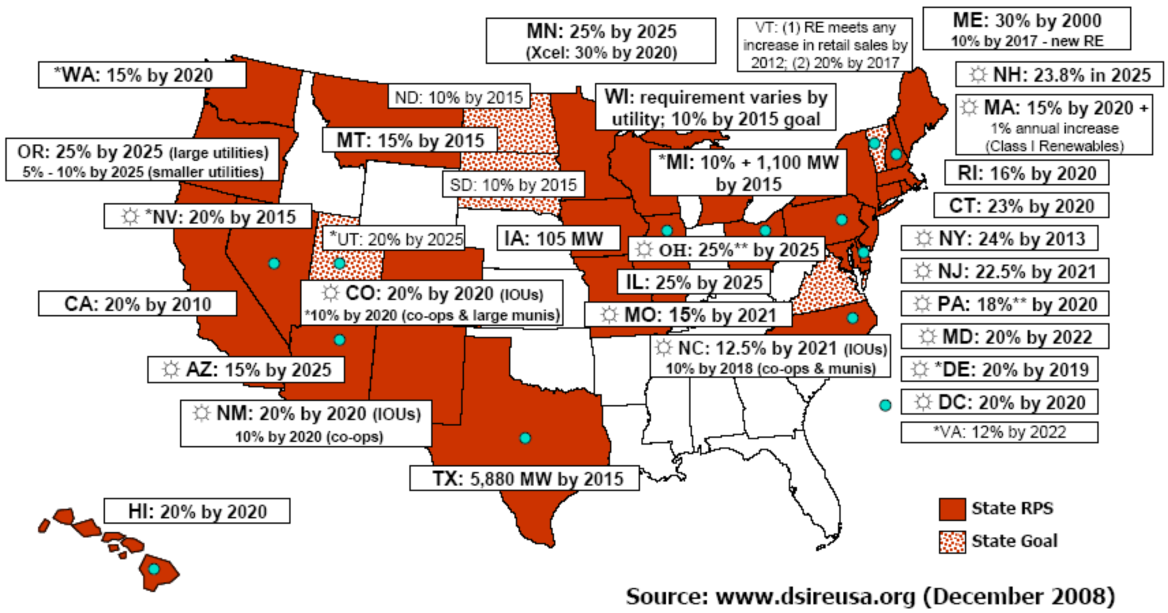

Figure 1: Summary of States with Renewable Portfolio Standards and Goals (Source: Database of State Incentives for Renewables & Efficiency, www.dsireusa.com [1]).

California has the most aggressive RPS requirements in the country calling for 20% renewables by 2010. The Governor of California recently signed an executive order calling for utilities to provide 33% of their power from renewable sources by 2020 [2]. The California Air Resources Board (CARB) recently followed suit and approved California's plan to reduce the state's greenhouse gas emissions to 1990 levels by 2020 [3].

In addition to RPS mandates, the United States appears to be moving towards implementation of a carbon cap-and-trade program to regulate and reduce carbon emissions with the new Obama administration [4]. The Regional Greenhouse Gas Initiative (RGGI), composed of 10 Mid-Atlantic and New England states, held its first auction of carbon dioxide allowances on September 25, 2008 with a second auction scheduled for December of 2008 [5]. The Western Climate Initiative (WCI), composed of several Western states and Canadian provinces, is following a similar path to RGGI [6]. These local actions to regulate carbon emissions are putting more and more pressure on the Federal Government to adopt a national carbon cap-and-trade program.

There are Federal incentives in the form of blending credits available to both biodiesel and ethanol. For biodiesel specifically, there is a Federal blending credit where for every percent of biodiesel blended with conventional diesel fuel, the Federal Government will provide a \$0.01/gal credit up to \$0.99/gal for a B99 blend of fuel (B99 is a blend of 1% petroleum diesel fuel and 99% biodiesel and receives a $0.99/gal Federal blending credit) [7]. For ethanol, the Federal blending credit is $0.51/gal for pure ethanol, $0.42/gal for E85 (85% ethanol) and $0.152 for E10 (10% ethanol) when blended with gasoline. The ethanol blending credit will change from $0.51/gal to $0.45/gal in 2009 [8].

Additional incentives for using biofuels for power generation include the Federal renewable electricity Production Tax Credit (PTC), Renewable Energy Credits (REC) and carbon credits. There are also additional Federal, State and Local investment tax incentives available for renewable energy projects using biofuels. These additional incentives can lead to substantial savings on capital equipment and on bottom line operating costs.

Biofuels

The major benefit of burning biofuels, such as biodiesel or ethanol, instead of conventional petroleum fuels is that the emissions are considered to be "carbon neutral" or "net zero" [9,10]. This designation takes into account the complete carbon cycle of the fuel including the growing cycle of the plant used as a feedstock to make the biofuel. As the feedstock plant grows, it removes CO_2 from the atmosphere. Hence, when the biofuel is burned, the resultant CO_2 is returned to the atmosphere as a "net" zero contribution to the environment.

The ethanol industry has recently experienced rapid growth to meet the ongoing demand for low carbon fuels for transportation. The growth in ethanol demand has been primarily driven by the Federal Renewable Fuels Standard (RFS). The RFS program requires that renewable fuels be blended into the nation's transportation fuels [11]. Ethanol production in the United States grew from 1.6 billion gallons per year (bgpy) in 2000 to 6.5 billion bgpy in 2007 [8].

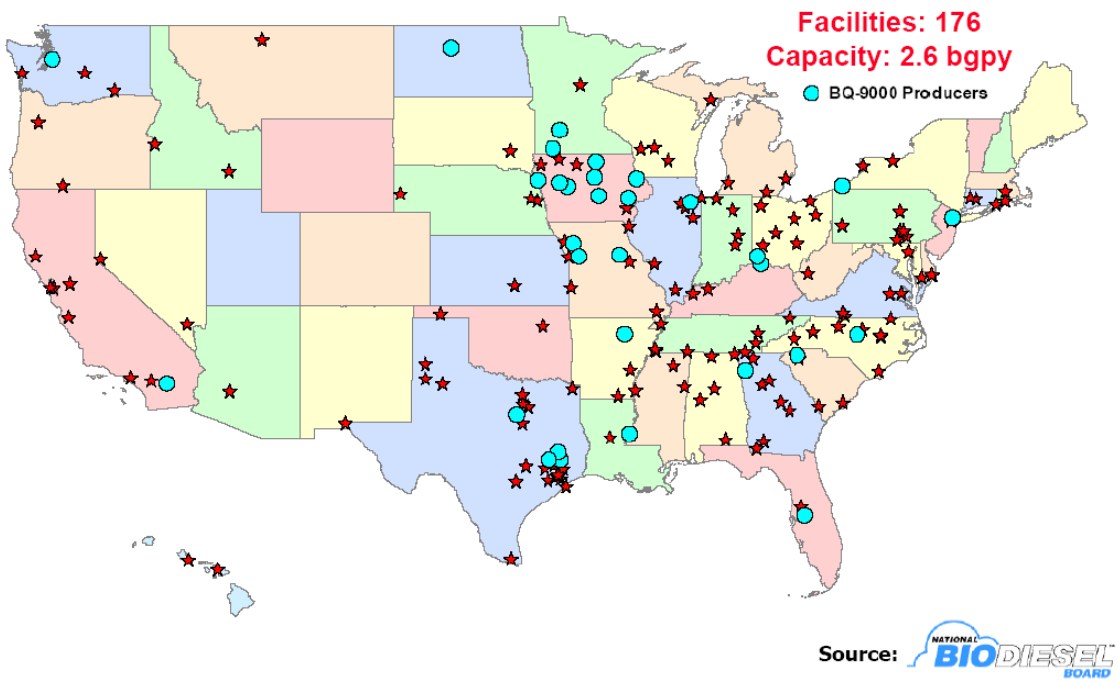

Figure 2: Location of commercial biodiesel production facilities in the United States and total production capacity as of September 29, 2008 (Source: National Biodiesel Board [7]).

The biodiesel industry is still in its infancy, but is poised for rapid growth to meet the ongoing demand for low carbon fuels for transportation and for renewable power generation. Figure 2 shows the current capacity for production of biodiesel from US producers. There are approximately 176 facilities with an annual production capacity of 2.6 bgpy [7]. The updated RFS passed in December of 2007 requires both ethanol and biomass derived biodiesel to be included in fuels for 2009 [11]. The requirement for biomass derived biodiesel to be included as part of the RFS is new for 2009.

ASTM International recently updated three specifications involving biodiesel and introduced a new specification to cover finished blends of biodiesel [12-15]. These include the specification for B100 blend stock (100% biodiesel) for middle distillate fuels (ASTM D6751-08), biodiesel blends from B6 to B20 (ASTM D7467-08), biodiesel blending in petroleum fuel in small amounts up to 5% biodiesel (ASTM D975-08a) and a specification for fuel oils used for home heating and boiler applications including requirements for up to 5% biodiesel blends. Additional quality standards for biodiesel include the national biodiesel accreditation program called BQ-9000 [16]. The program is a unique combination of the ASTM standard for biodiesel, ASTM D6751, and a quality systems program that includes storage, sampling, testing, blending, shipping, distribution, and fuel management practices.

Biofuel production capacity continues to grow in the United States and internationally to meet the challenges of combating global climate change. The main uses for biofuels going forward include transportation and power generation markets. As these markets demand more biofuels, additional improvements in product specifications and producer quality programs will continue to evolve. As these fuels become more of a standardized and controlled commodity, like petroleum based fuels, their use will continue to grow as a solution to combat global warming.

Conventional Liquid Fuel Combustion

Traditionally, spray diffusion burners (Figure 3, left) have been employed in gas turbines that operate on liquid fuels, including petroleum based fuels such as naphtha, kerosene and diesel and for renewable fuels such as ethanol and biodiesel. However, this diffusion mode of operation produces high emission levels of NO_x, CO and particulate matter. The current technology for burning liquid fuels in gas turbines is to use water and/or steam injection with conventional spray diffusion burners. Emissions levels for a typical “state of the art” gas turbine, such as a GE 7FA burning fuel oil #2 in diffusion mode with water/steam injection, are 42 ppm NO_x and 20 ppm CO [17]. Water/steam injection has a dilution and cooling effect,

Figure 3: Conventional liquid fuel spray diffusion flame (left) and typical lean, premixed natural gas flame (right)

lowering the combustion temperature and thus lowering NO_x emissions. However, water/steam injection is likely to increase CO emissions as a result of local quenching effects. Thus, the "wet" diffusion type of combustion system for liquid fuels must trade off NO_x emissions for CO emissions and still result in high levels of particulate matter.

In recent years, stringent emissions standards have made lean, premixed combustion more desirable in power generation and industrial applications than ever before, since this combustion mode provides low NO_x and CO emissions without water addition. Lean, premixed combustion of natural gas avoids the problems associated with diffusion combustion and water addition. As a result, lean, premixed combustion has become the foundation for modern Dry Low Emissions (DLE) gas turbine combustion systems. When operated on natural gas, DLE combustion systems provide NO_x and CO emissions of 25 ppm or less without water addition.

However, these DLE systems cannot currently operate in premixed mode on liquid fuels because of autoignition and flashback within the premixing section. Autoignition of the fuel/air mixture can occur before the main combustion zone, when the ignition delay time of the fuel/air mixture is shorter than the mean residence time of the fuel in the premixer. Autoignition is more likely to occur with the higher-order hydrocarbon fuels, such as fuel oils and biodiesel, which have shorter ignition delay times compared to natural gas [18]. The short ignition delay times of vaporized higher hydrocarbons have proven difficult to overcome when burning in lean, premixed mode.

Several approaches have been reported in the literature [19-27] to overcome flashback and autoignition in the premixers of LPP combustors. These approaches attempt to achieve low NO_x emissions by designing premixers and combustors that permit rapid mixing and combustion before spontaneous ignition of the fuel can occur. In most of the work reported on LPP combustion systems in the literature, the fuel is sprayed directly into the premixer so that the liquid fuel droplets vaporize and mix with air at lean conditions. These previous attempts at burner hardware changes were unsuccessful in reducing the time it takes to vaporize liquid fuels in air and resulted in no successful commercialized LPP combustion systems. However, unlike these attempts to alter hardware, there has been no reported work on altering fuel combustion characteristics in order to delay the onset of ignition in lean, premixed combustion systems. In this study, vaporization of the liquid fuel in an inert environment has been shown to be a technically viable approach for LPP combustion.

The LPP Combustion Process

A patented fuel vaporization and conditioning process [28,29] was developed and tested to achieve low emissions (NO_x, CO and PM) comparable to those of natural gas while operating on liquid fuels, without the need for water or steam addition. In this approach, liquid fuel is vaporized in an inert environment to create a fuel vapor/inert gas mixture, called LPP Gas™, with combustion properties similar to those of natural gas. Premature ignition (autoignition) of the LPP Gas™ is controlled by the level of inert gas added during the vaporization process. An added advantage of the fuel vaporization and conditioning process is the ability to achieve fuel-interchangeability of a natural gas-fired combustor with liquid fuels. The fuel switching change over from natural gas to LPP Gas™ is done on the fly and does not require the turbine to be shut down. Tests conducted in both atmospheric and high pressure test rigs utilizing commercial dry low emission (DLE) burners (designed for natural gas) found operation similar to that achieved when burning natural gas [30,31].

Figure 4 shows a simplified process diagram for the LPP System used for this study. Liquid fuels were supplied to the LPP fuel conditioning skid using a fuel pump. An inert gas (nitrogen) and heat were provided to the LPP skid in order to vaporize and condition the liquid fuel. Although nitrogen was used for this application, other inert diluents such as exhaust gas or carbon dioxide could also be used. For testing purposes, the heat was applied to the skid using electrical heaters. For commercial systems, combinations of electrical, thermal and waste heat could also be used to provide energy for fuel heating and vaporization. In order to maximize system efficiency for commercial application, waste heat utilization is the preferred method to supply heat to the skid. Once the liquid fuel is vaporized and conditioned in the LPP System, the resulting LPP Gas™ can be used as a substitute for natural gas and used in potentially any combustion device originally designed for natural gas. The resulting emissions from burning LPP Gas™ are similar to those for natural gas including NO_x, CO and particulate matter. Since both biodiesel and ethanol contain little or no sulfur, natural gas emission levels for SO_x are also achieved. The same clean blue flame typical of natural gas is achieved when burning LPP Gas™ derived from liquid fuels.

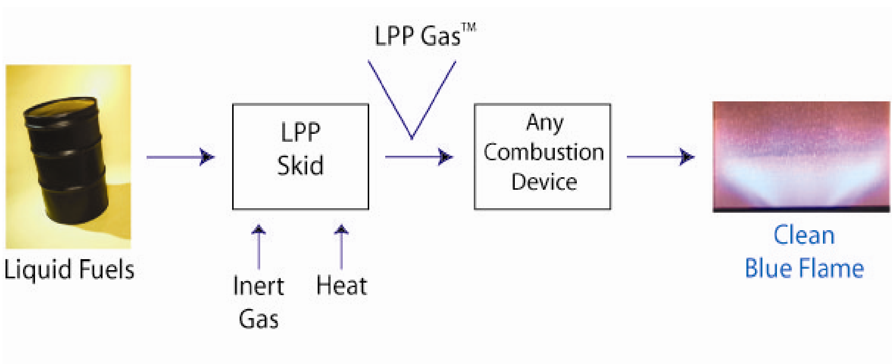

Figure 4: LPP Combustion process diagram

The LPP Combustion System changes the nature of the fuel by adding an inert gas during the vaporization process thus preventing autoignition during the relevant timescales for fuel transport, mixing and burning with air. The vaporization of liquid fuel takes place away from the combustion device in a separate skid-based fuel conditioning device under temperature conditions much less severe than in the combustor. This reduces burner maintenance compared to traditional spray diffusion methods.

Biofuels Testing

The testing of biofuels using the LPP Combustion System was performed in an atmospheric pressure combustor rig using a Solar Turbines Centaur 50 natural gas nozzle. The Centaur 50 gas nozzle utilizes Solar Turbine's lean premixed $SoLoNO_x$ dry low emission (DLE) combustion technology. The same commercial gas burner hardware was used for both natural gas and liquid biofuels (as LPP Gas™) without any modification. The biodiesel used for testing was ASTM D6751 grade soy-oil based soy-methyl-ester (SME). This grade of biodiesel is referred to as B100 or 100% biodiesel. The ethanol used for testing was ASTM

D4806 grade denatured fuel ethanol for blending with gasoline for use as an automotive spark-ignition engine fuel. Figure 5 shows the LPP System and atmospheric pressure test facility used to evaluate various fuels using the LPP Combustion Technology.

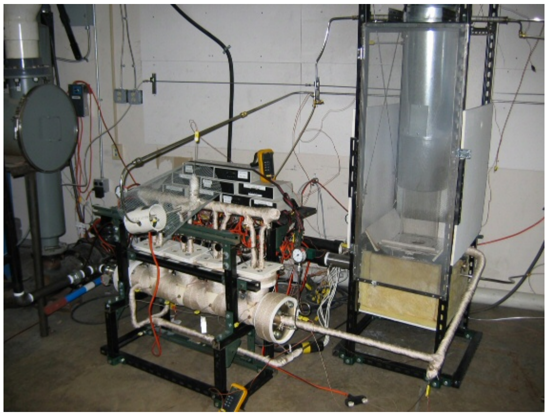

Figure 5: Atmospheric pressure combustor test facility used to evaluate emissions for various fuels using LPP Combustion Technology.

Combustor inlet temperatures were maintained at typical compressor discharge temperatures of 600 K to 630 K. Figure 6 shows a photograph comparing the biodiesel flame and the natural gas flame using the same commercial burner. Figure 6 shows that the biodiesel burned as a lean, premixed LPP Gas™ also produces a clean, light blue flame of similar shape and form as the natural gas flame.

Figure 6: Lean, premixed natural gas flame (left) and lean, premixed, prevaporized biodiesel flame (right)

Figure 7 shows a comparison of NO_x emissions obtained for biodiesel and ethanol with those of natural gas, fuel oil #1 and fuel oil #2. As can be seen in the Figure, the biodiesel, ethanol and fuel oil #1 emissions are similar to those obtained from natural gas and are lower than the NO_x emissions obtained from fuel oil #2. The results for the biofuels and fuel oil #1 are to be expected since these fuels contain no significant amounts of fuel-bound nitrogen or sulfur. The slightly elevated NO_x emissions for the fuel oil #2 were the result of fuel bound nitrogen being present in the fuel (0.04% by weight). When fuel bound nitrogen is present, the nitrogen is quantitatively converted to NO_x during combustion.

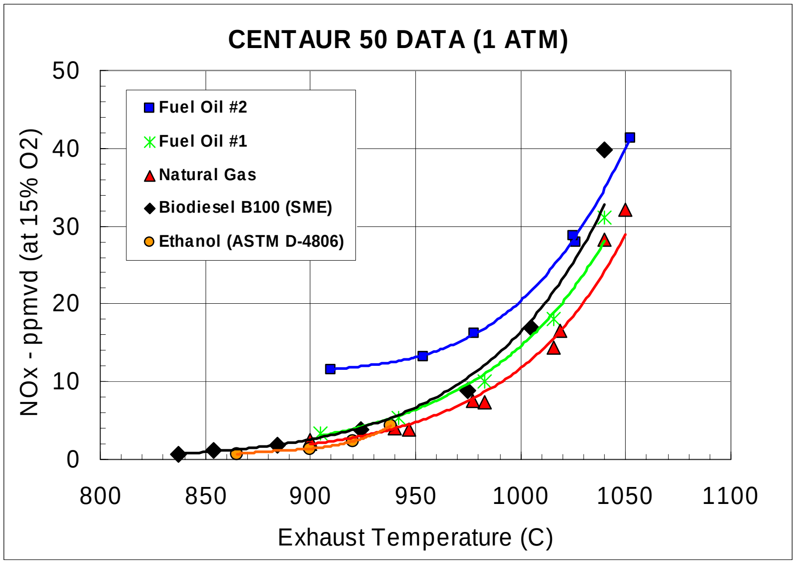

Figure 7: Comparison of NO_x emissions for natural gas, fuel oil No. 2, fuel oil No. 1, biodiesel (soy methyl ester, SME, ASTM D6751) and ethanol (ASTM D-4806).

Figure 8 shows a similar comparison of CO emissions obtained for biodiesel and ethanol with those of natural gas, fuel oil #1 and fuel oil #2. This Figure shows that the biofuels also produce very low CO emissions when burned lean, premixed and prevaporized using the LPP Combustion technology. Unlike some combustions systems where NO_x and CO emissions are traded-off with each other, the LPP Combustion technology simultaneously achieves both low NO_x and CO emissions when burning liquid fuels.

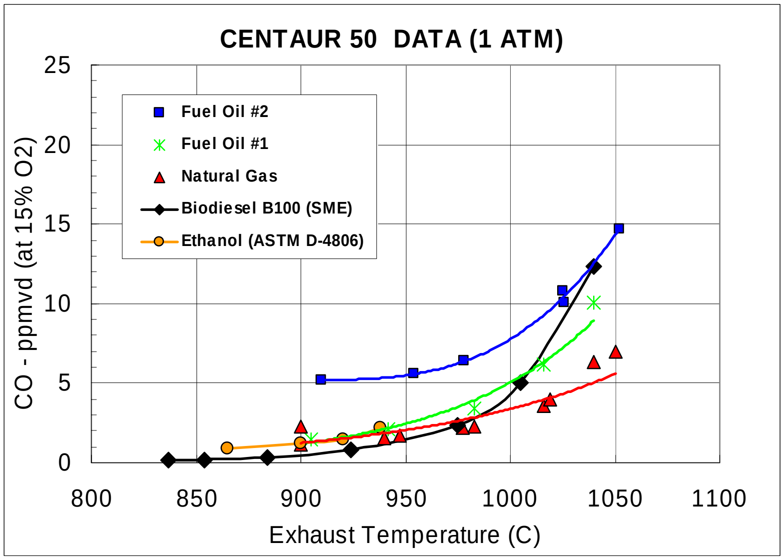

Figure 8: Comparison of CO emissions for natural gas, fuel oil No. 2, fuel oil No. 1, biodiesel (soy methyl ester, SME, ASTM D6751) and ethanol (ASTM D-4806).

These tests demonstrate that the LPP Combustion System is capable of burning biodiesel and ethanol in a gas turbine combustor with NO_x and CO emissions similar to those obtained from operation on natural gas. These results were obtained using a commercial DLE gas turbine nozzle designed for lean, premixed combustion of natural gas with no modifications to the nozzle hardware. The pollutant emission levels achieved are much lower than can be obtained when using these fuels in conventional spray diffusion burners, which is how liquid fuels are burned today in gas turbines or reciprocating engines. Extended lean operation was found for the liquid fuels tested due to the wider lean flammability range of liquid fuels compared with natural gas. The LPP Combustion System has demonstrated natural gas level emissions from biodiesel and ethanol without the need for water injection or expensive post-combustion cleanup devices such as selective catalytic reduction (SCR). An added advantage of the LPP fuel vaporization and conditioning process is the ability to achieve fuel-interchangeability of a natural gas-fired combustor with liquid fuels.

Summary of Emissions Testing

The emissions and operational characteristics of the Lean, Premixed, Prevaporized (LPP) combustion technology described in this paper represent a new and clean way of burning a wide range of liquid fuels including renewable biofuels such as biodiesel and ethanol. The LPP technology focuses on changing the characteristics of the fuel rather than trying to change the combustion hardware. Since the LPP Combustion system utilizes existing burners designed for natural gas, no changes to the DLE gas turbine combustor hardware were required. The LPP Combustion system provides the capability to cleanly burn liquid fuels and achieve natural gas level emissions without the need for water addition to the combustor or post combustion pollution control equipment.

The LPP technology demonstrated that natural gas level emissions can be obtained for biofuels including both biodiesel and ethanol. Figure 9 shows a summary of the NO_x performance for a range of fuels using LPP Combustion technology compared to both natural gas (DLE baseline) and fuel oil #2 burned as a spray diffusion flame with water addition (state-of-the-art benchmark for liquid fuels).

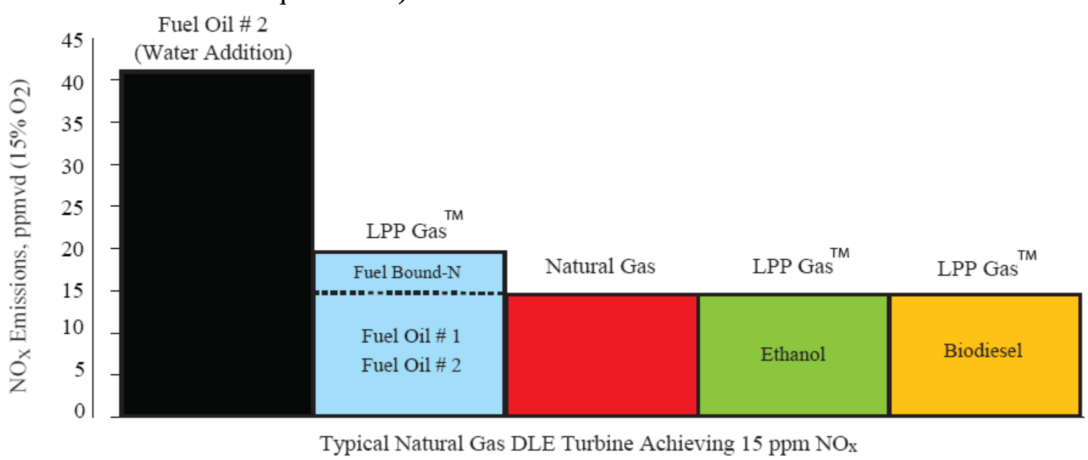

Figure 9: Summary of NO_x emissions performance for a range of fuels using LPP Combustion technology compared to a nominal 15 ppmv NO_x natural gas DLE fuel nozzle and conventional spray diffusion nozzle with water addition.

The LPP System using biofuels, such as biodiesel or ethanol, creates a reliable and dispatchable renewable energy generator that can help states meet both their RPS mandates and carbon cap restrictions. Unlike the conventional burning of biofuels in gas turbines using spray diffusion burners and water injection, the LPP Combustion System produces natural gas level criteria pollutant levels for NO_x, CO, SO_x and PM along with no net carbon emissions.

Improved Heat Rate

While beneficially reducing NO_x emissions, water injection used for NO_x control in traditional spray flame (diffusion) combustors incurs a substantial negative impact on the efficiency and maintenance of a liquid-fueled gas turbine. Water addition reduces the NO_x emissions by reducing the flame temperature, but this in turn also reduces the thermodynamic efficiency of the gas turbine. In addition, the energy required to vaporize the injected water further reduces the gas turbine efficiency. Lastly, the reduced firing temperature also reduces the exhaust temperature of the gas turbine for liquid-fueled operation, which in turn reduces the amount of steam production for a combined cycle plant. All of these effects serve to increase the net plant heat rate (and cost of operation) for a traditional liquid fueled gas turbine combined cycle power plant.

In contrast, a combined cycle plant which is fueled by LPP Gas™ is not subject to the above losses. A gas turbine fueled by LPP Gas™ may be operated at the higher natural gas firing temperature, thereby avoiding the reductions in efficiency noted above. Since there is no water injection with the LPP System, that vaporization loss is also avoided. Combined cycle performance calculations have shown that for a typical single pressure level heat recovery steam generator (HRSG) and GE Frame 7EA class gas turbine, one can expect to achieve at least a two percent (2%) improvement in the overall combined cycle plant heat rate when burning biodiesel as LPP Gas™ as compared against burning the same liquid fuel in traditional spray-flame diffusion combustors with water injection. If ethanol is burned, a three and a half percent (3.5%) improvement in heat rate can be expected compared to traditional combustors. These calculations were made using the GateCycle™ [32] power plant modeling software, and the losses associated with a fully integrated LPP system were included in the calculation of the net plant heat rate. This level of heat rate improvement is quite substantial, and represents an annual fuel savings of over $2.5 million dollars when burning biodiesel for base load operation of a GE Frame 7EA combined cycle plant (126 MW). Biodiesel (B99) was assumed to be $2.00 per gallon for the above economic analysis.

Carbon Emissions

As mentioned earlier, the major benefit of burning biofuels, such as biodiesel or ethanol, is that the emissions are considered to be "carbon neutral" or "net zero" [9,10]. Conventional application of biofuels to gas turbines for the generation of renewable energy encounters the same emissions limitations on NO_x, CO and particulate matter as conventional petroleum fuels [33,34]. Water or steam addition is required in spray diffusion burners to achieve the "state-of-the-art" benchmark level of 42 ppmv NO_x @15% O_2. The emission results from burning liquid fuels using the LPP Combustion technology presented in this paper and others [30,31] show that the LPP technology offers a significant improvement over the 42 ppm NO_x level for liquid fuel operation and that natural gas level emissions can be achieved. Gas turbine plants permitted for liquid fuel operation are typically restricted, based on emissions, to approximately 500 hours of annual operation. Since the LPP Combustion technology achieves natural gas level emissions for liquid fuels, this allows for significant additional run time under a plant's existing air permit.

Figure 10 shows a comparison of various combustion technologies used for large scale power production. In order to combat global warming, California and other states have adopted an emissions performance standard (EPS) for carbon dioxide emissions of 1,100 lb CO_2/MWh [35]. Conventional boilers have low thermal efficiencies and produce significant levels of carbon emission whether coal, oil or natural gas is used. Both natural gas and oil fired combined cycle gas turbines can meet the 1,100 lb CO_2/MWh. However, for practical purposes, conventional oil-fired gas turbines are severely restricted on annual hours of operation due to high levels of criteria pollutant emissions (primarily NO_x). This would also be the case for burning biofuels conventionally in spray diffusion burners. Since the LPP combustion technology achieves natural gas level emissions for criteria pollutants, a biodiesel fired combined-cycle gas turbine could achieve the 1,100 lb CO_2/MWh EPS and not be restricted on annual operation.

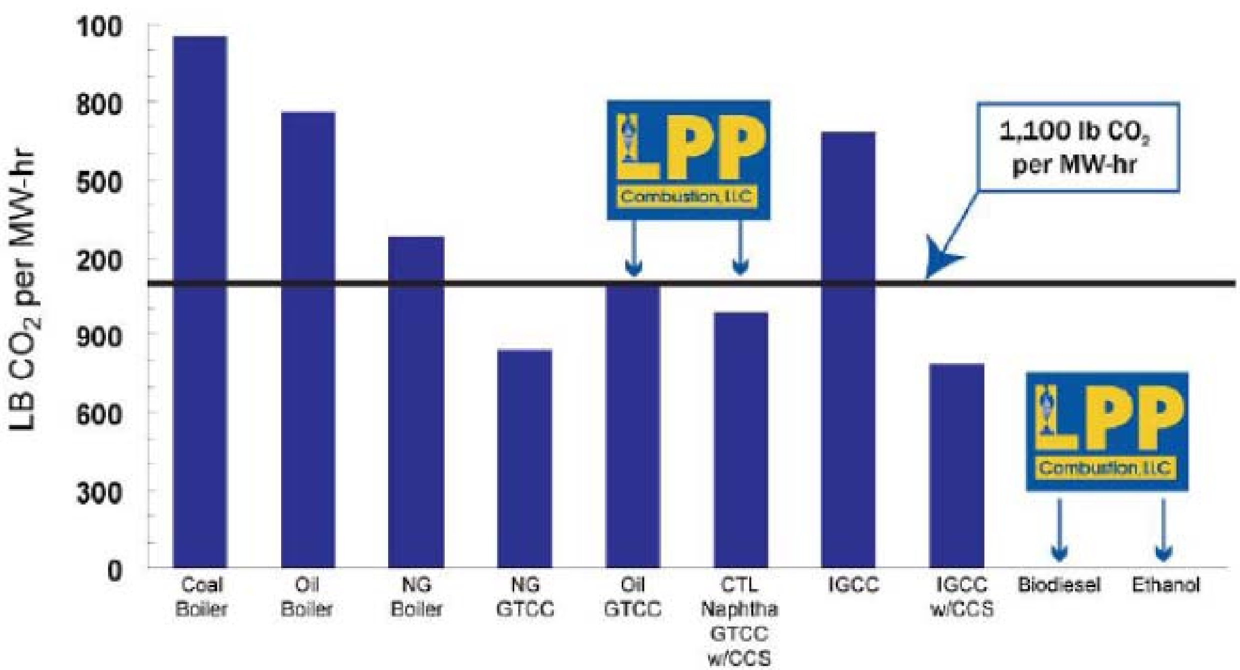

Figure 10: Summary of net CO_2 emissions from various power generation sources

Several clean coal technologies such as integrated gasification combined cycle (IGCC) and coal to liquids (CTL) derived from the Fischer-Tropsch process can achieve natural gas criteria pollutant levels, but still require expensive carbon capture and storage (CCS) in order to meet the 1,100 lb CO_2/MWh EPS. Since the combustion of biofuels is considered to be carbon neutral, the amount of carbon in the earth's atmosphere remains unchanged, thus costly post combustion carbon capture and storage equipment is not required. Burning biodiesel or ethanol using LPP Combustion technology achieves both natural gas level emissions for criteria pollutants and no net carbon emissions thus representing the cleanest use of renewable fuels for power generation.

Conclusions

The LPP Combustion technology presented in this paper represents the cleanest use of biofuels and achieves natural gas levels of criteria pollutants (NO_x, CO, SO_x & PM) and no "net" carbon emissions. Since the combustion of biofuels is considered to be carbon neutral, the amount of carbon in the earth's atmosphere remains relatively unchanged, obviating the need for costly post combustion carbon capture and storage equipment to reduce carbon emissions. The LPP Combustion system provides the capability for tremendous fuel flexibility and low emission not previously attainable in modern DLE gas turbines with liquid fuels. The LPP Combustion technology provides fuel flexibility between natural gas and biofuels, enables the cleanest use of renewable fuels, and provides substantial operating cost savings for liquid fueled combined cycle power plants.

This technology provides a clean and reliable form of renewable energy using liquid biofuels that can be a primary source for power generation or be a back-up source for inconsistent renewable energy sources such as wind and solar. The technology allows for the clean use of biofuels in combustion devices without the use of costly post-combustion pollution control or carbon capture and storage equipment and can easily be incorporated into both new and existing gas turbine power plants. No changes are required to the DLE gas turbine combustor hardware that currently allows for clean, efficient combustion of natural gas. The clean combustion of biofuels achieved using LPP Combustion technology represents a solution to help combat global warming for the power industry that is available today to help meet renewable portfolio standards and carbon regulations.

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