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Enabling ethane as a primary gas turbine fuel: an economic benefit from the growth of shale gas

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Abstract

Gas turbines are used extensively throughout the world as an efficient and relatively clean source of electricity and power for utility, industrial and refinery processes. Natural gas is typically the fuel of choice for most installations because of its availability, low cost, combustibility and low emissions. However, outside of the United States many countries have limited natural gas reserves requiring them to use alternative fuels for power generation.

A common natural gas alternative in many parts of the world is liquefied natural gas (LNG), which has carried a price many times higher than natural gas in the USA. The search for suitable alternatives has led to projects that may operate on a variety of fuels, including lean methane, non-methane hydrocarbons, crude oil, and syngas. The category of non-methane hydrocarbons now includes ethane and propane, which are becoming available in suitable quantities due to shale gas production in the USA. Both ethane and propane can be used for power generation, and with the recent announcements of ethane export terminals in the USA, there is now an option for exporting ethane as an LNG alternative for power generation. GE's combustion technology allows our gas turbines to operate on fuels with varying levels of ethane and propane, which could have significant impact on plant economics.

Introduction

GE has long manufactured gas turbines that are configured to meet stringent emissions standards, provide efficient, reliable power generation, and operate on a wide range of liquid and gaseous fuels [1,2]. Changes in global dynamics with growing energy demands and fuel price volatility have created the need for increased operational and fuel flexibility from power generating equipment. The graph in Figure 1 shows fuel price volatility over the last nine years. Although the USA has been experiencing an extended period of low natural gas prices, the price volatility shown in Figure 1 is driving global interest in non-traditional fuels. At the same time, the availability of non-methane hydrocarbon fuels has increased. These factors have created a need for greater gas turbine combustion fuel flexibility.

This paper provides an overview of:

- Recent industry shifts associated with high hydrocarbon fuels
- Related gas turbine combustor technical challenges associated with these fuels
- GE's heavy-duty gas turbine combustor capabilities using these fuels (with an emphasis on ethane and propane)
- The economic benefits of lower fuel prices on power plant economics

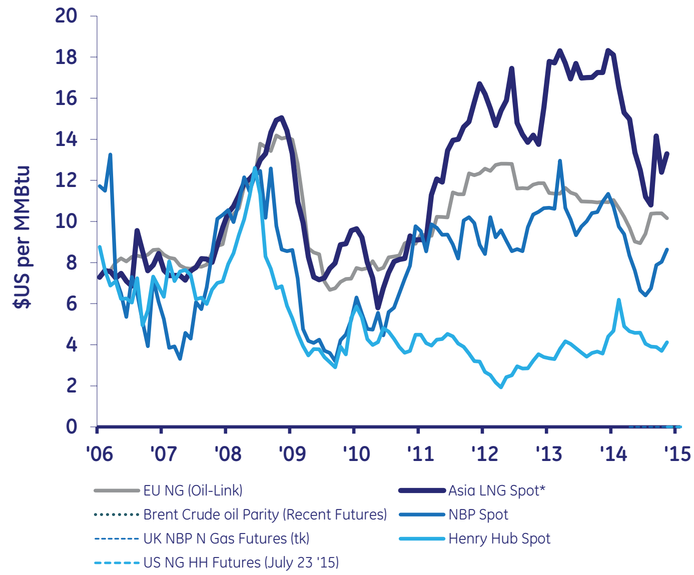

Figure 1 – Volatility of fuel prices, 2006-2015

Fuel Supply Dynamics

Worldwide growth in the availability of high hydrocarbon fuels has created a new alternative for power producers challenged to find affordable and clean-burning fuels. In particular, the rapid increase in USA propane and ethane production (see Figure 2), coupled with the development of new infrastructure and export terminals, has begun to enable power generation from propane and ethane, both domestically and internationally.

The growth of propane production in the United States has primarily come from shale gas fracking, leading the country to become a net exporter of propane for the first time in 2011 [3]. Additional growth in propane production is expected to be exported, as global demand for low cost and cleaner fuels increases. Propane export infrastructure in the USA is also being developed to support the increase in supply, with new export terminals proposed to be online in Texas, Pennsylvania, and Canada by 2017. Propane has traditionally been used as a fuel for cooking and heating, and as an alternative fuel for transportation. It is now being considered a viable fuel source for power generation, especially in locations with high fuel costs like Latin America.

For example, the Virgin Islands Water and Power Authority (VIWAPA) announced in 2013 the switch from fuel oil to propane as its primary fuel for power generation. This fuel change will result in substantial cost savings and reduced emissions. The project includes the conversion of several of GE's gas turbines to propane operation [4,5].

The case for ethane is similar to propane, with supply increasing dramatically as natural gas liquids from shale gas have become more plentiful in the United States. However, ethane has traditionally been used exclusively as a feedstock

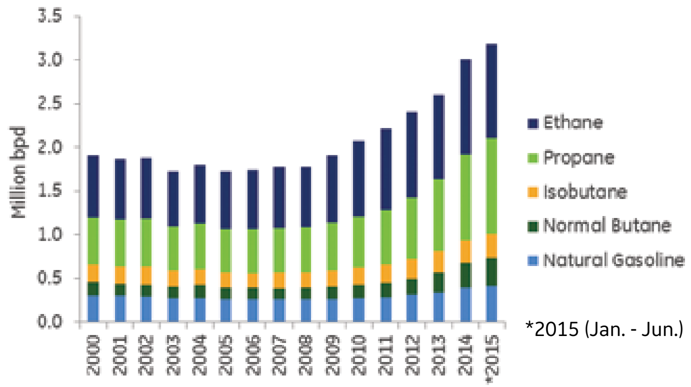

Figure 2 – Hydrocarbon gas liquids (HGL) production in the USA, 2000-2015 [6]

for the petrochemical industry. As the increasing supply from unconventional gas production outpaces the current and potential future petrochemical demand, ethane is being considered as a fuel for power generation both in the United States and globally. The excess supply of propane and ethane is driving a reduction in prices (as shown in Figure 3), providing financial incentive to use these fuels where they are available. At natural gas liquids (NGL) hubs in the United States, the price of natural gas typically sets a price floor for ethane on an energy equivalent basis, but there are opportunities for this fuel where there is a local oversupply, or if it can be exported and delivered at a lower cost than LNG. If ethane continues to be priced at or near natural gas, there is the potential for the landed costs of exported ethane from the USA to be less expensive than LNG in some parts of the world, creating a scenario in which ethane could be a lower cost alternative fuel for power generation.

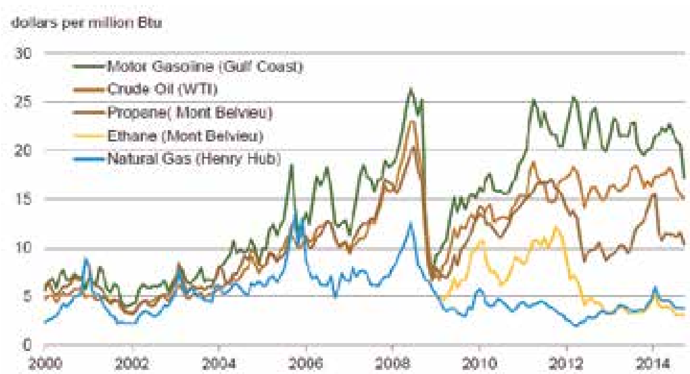

Figure 3 - Comparison of spot prices, 2000-2014 [7]

The increased availability and low price of ethane drives the development of new infrastructure projects for transporting ethane both domestically and internationally [8-11], supporting the potential use of ethane as a global power generational fuel. Infrastructure to transport ethane from Marcellus and Utica Shale areas in western Pennsylvania, West Virginia and Eastern Ohio to a port in eastern Pennsylvania is under development [12]. Export terminals in Pennsylvania and Texas are planned for 2016 completion along with ships for transporting ethane [13-15]. The first shipment of USA ethane to Europe is expected to be delivered in late 2015 to the INEOS steam cracker in Rafnes, Norway [16].

Figure 4 shows schematically how ethane from unconventional gases, including shale gas, is being used in the United States as a feedstock for the petrochemical industry, and how it could be blended with natural gas or used separately for power generation. Dark blue arrows show how ethane is being used in the USA today; it is primarily being used for petrochemical applications, although there is at least one project that has used a blend of ethane and natural gas in a power generation application. The light blue arrows show how ethane could be used in the near future. Co-locating power generation with petrochemical plants that use ethane as a feedstock could help reduce infrastructure costs and mitigate fuel supply risks.

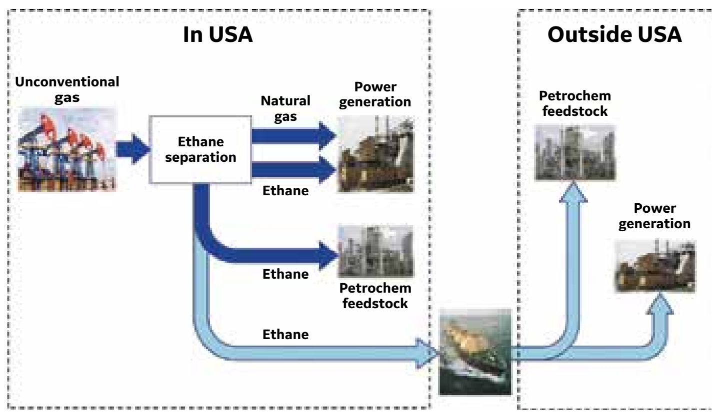

Figure 4 - Use of ethane for petrochemical and power generation

The concept of using ethane for power generation in the USA is being validated by a new project in West Virginia. Moundsville Power recently announced plans to construct a first-of-a-kind combined cycle power plant [17] that will be fueled by a combination of natural gas and ethane, enabled by expanding local fuel supplies. On this project, one analyst commented, “We see the use of conventional GE turbines as potentially heralding a new series of plants located in the western regions of the Pennsylvania-New Jersey-Maryland (PJM) Interconnection, where cheap ethane is to be found.” [18] The PJM Interconnection is a regional transmission organization that operates the electrical grid serving a number of states in the Midwest and Mid-Atlantic regions. Other power producers and developers have acknowledged exploring a similar approach to using ethane.

Increased use of these high hydrocarbon alternate fuels will depend on infrastructure and transportation development such as pipelines, liquefaction, storage, tankers and re-gasification. Infrastructure development along the east coast of North America will provide easier access to Europe and Africa. Gulf Coast expansions in the USA could support fuel exports to Latin America. The Panama Canal expansion, scheduled for completion in 2015, could allow easier access to power plants in Asia.

Hydrocarbon Sources and Characteristics

Hydrocarbons are defined as organic compounds that contain both carbon and hydrogen. They range in complexity from very simple molecules, such as methane that has one atom of carbon and four hydrogen atoms, to more complex molecules with multiple carbon and hydrogen atoms. The simplest hydrocarbons, which are in the Alkane group, are listed in Table 1. As the molecular weight increases, the boiling point increases as does the heating value (on a volumetric basis); the heating value on a mass basis actually decreases with increasing fuel molecular weight.

Natural gas

Natural gas is a mixture of multiple gases, with methane content ranging from roughly 70 to 90 percent. The remaining gases can be ethane (C_2H_6), propane (C_2H_8), nitrogen (N_2), carbon dioxide (CO_2), and even hydrogen sulfide (H_2S). The United States Environmental Protection Agency (EPA) defines natural gas as having greater than 70 percent methane, a heating value between 950 and 1100 British thermal units (BTUs) per standard cubic foot, and less than 20 grains per 100 standard cubic feet of sulfur [19]. (Sulfur concentration of 20 grains per 100 standard cubic feet is approximately 314 parts per million on a volumetric basis.)

Table 1 – Alkane hydrocarbon properties

	Formula	Molecular Weight	Boiling Point (° C)	Heating Value, LHV (kJ/m3)	Heating Value, LHV (kJ/kg)
Methane	CH_4	16	-162	35,817	50,043
Ethane	C_2H_6	30	-89	63,752	47,522
Propane	C_3H_8	44	-42	91,263	46,398
Butane	C_4H_{10}	58	-0.5	118,695	45,773
Pentane	C_5H_{12}	72	36	146,097	45,387
Hexane	C_6H_{14}	86	68	171,075	44,496

Natural gas is produced from wells that generally fall into two categories: associated and non-associated. Associated wells primarily produce crude oil; the natural gas is associated or pumped along with the crude oil. In non-associated wells, the natural gas is pumped from dedicated wells without any crude oil production. Natural gas can come from conventional wells of gas trapped in pockets capped (or sealed) by cap rock, or from gas-rich shale formations (as shown in Figure 5).

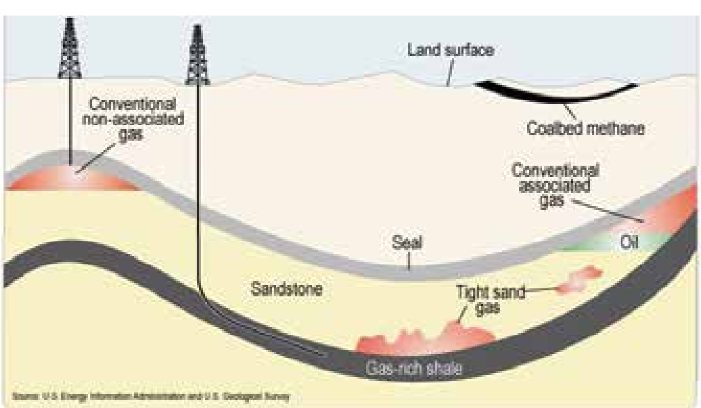

Figure 5 – Sources of fossil fuels [20]

When natural gas comes out of the ground, it can be classified as dry or wet. Dry gas is natural gas that is substantially free of natural gas liquids (NGL), which are defined as molecules larger than methane (for example: ethane or propane) found in association with methane in natural gas. The opposite of dry gas is wet gas, which is defined as having significant content of non-methane hydrocarbons (also known as natural gas liquids).

Liquefied natural gas

Liquefied natural gas (LNG) is made from natural gas by removing most of the non-methane hydrocarbons and then condensing to a liquid by cooling to a temperature below the boiling point (-162°C). As a liquid, LNG takes up less than 1/600th the volume of a gas with the same energy content, enabling much simpler and more cost-effective global transportation by ship. Once a tanker containing LNG arrives at its destination, the liquid is converted back into a gas and then distributed to end users.

Higher molecular weight hydrocarbons

Ethane, propane and other higher molecular weight hydrocarbons can be found in varying concentration in natural gas wells. By definition, as described previously, these compounds are found in higher concentration in wet gas, which is found in locations in the USA.

These hydrocarbons can be extracted from natural gas as shown by the schematic in Figure 6. The exact percentage of these compounds available from processing and fractionation depends on the composition of the gas from a particular well or field. This variation in content can prevent a gas turbine from operating, or impact the turbine's performance. The next section provides a summary of combustion system considerations that are important when operating a gas turbine on these fuels.

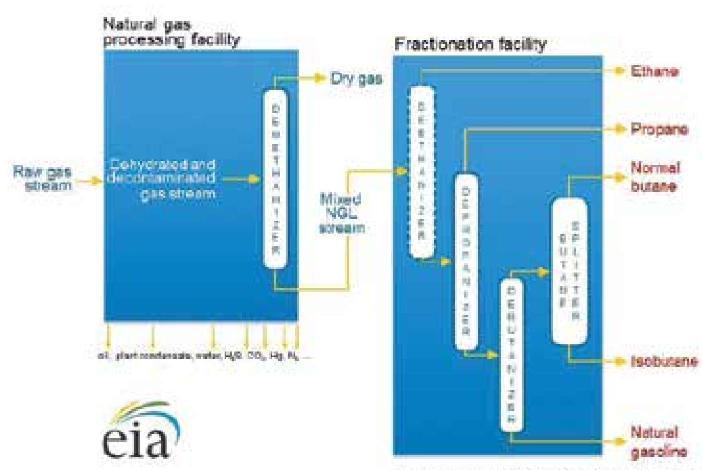

Figure 6 – Natural gas processing and fractionation schematic [7]

Combustion System Considerations

The configuration of a combustor for a heavy-duty gas turbine needs to provide stable operability characteristics as well as capabilities such as turndown, while meeting plant emissions criteria [21].

These constraints are not independent and cannot be optimized separately. Fuels with increased (or reduced) heating value could have an increased risk of not meeting these criteria. For example, ethane is more reactive than natural gas, which might lead to a greater risk of combustion dynamics or flame flashback, or increased NO_x emissions. This section defines these challenges and mitigation strategies. A later section in this paper describes the various combustion systems available.

Flashback

In a lean, premixed combustion system, flash back can occur when transient conditions allow the local flame speed to exceed the local air velocity and the flame is able to propagate upstream from the combustion zone into the premixer or fuel nozzle [22,23]. When this happens, the metal temperatures may increase to unacceptable levels and hardware damage may occur [21]. In severe cases, the damage may lead to a forced outage. Flame holding can occur after flashback if the flame attaches or "anchors" to the fuel nozzle. As with flashback, this may cause damage to combustion hardware.

Using higher molecular weight hydrocarbons, such as ethane, can create additional risks for flashback as the laminar flame speed (or the speed at which the flame propagates upstream into the unburned fuel) is higher than that of methane. Although the flame speed for ethane is similar to that of methane, the flame speed for propane and butane can be twice as fast as methane [24]. Operating a lean-premixed combustion system (also known as a dry low NO_x or DLN combustion system) with hydrogen creates an even larger flashback risk, as its laminar flame speed is six to seven times faster than methane [25].

GE determines the risk of flashback in a combustion system by examining the behavior during a forced ignition event performed during combustion testing. During this flame holding test, a torch is placed upstream of the fuel nozzle sending a flame through a premixer for a short duration. Ideally, a premixing fuel nozzle should be able to clear the flame after the torch is extinguished [26]. This data is used during the development cycle to reduce the flashback risk.

Combustion Dynamics

The phenomenon of combustion dynamics, also known as resonant pressure oscillations, arises from the interaction of the thermo-acoustic source (the flame) with the combustion hardware. Small changes in fuel/air concentration cause fluctuations in the flame's heat release rate, which leads to pressure oscillations [27]. Shifts in fuel heating values may trigger combustion dynamics in some combustion systems. The potential for combustion dynamics can be higher in lean-premixed combustion systems (relative to diffusion flame systems) as there can be large changes in heat release for very small changes in fuel-air ratio. If left unchecked, these instabilities may impact gas turbine operability, and in worse-case scenarios, may cause degradation or damage to combustion hardware [28-31].

To mitigate the risk of combustion dynamics, GE employs multiple configuration and operational strategies to decouple the feedback loop between the flame and the fuel flow rate. These configuration-based mitigations can be evaluated using analytics models and lab testing [32]. GE's gas turbines can also be configured with our sophisticated OpFlex* AutoTune control system that allows the gas turbine to accommodate changes in fuel heating value. This system includes an adaptive real-time engine simulation, which is an aero-thermal model of the gas turbine that supports physics-based boundary models [33]. In operation for more than eight years, the OpFlex AutoTune system has been installed on more than 130 gas turbines, and has accumulated more than one million operating hours.

Emissions

Operating on a more reactive fuel can increase flame temperature. Depending on the level of increase and gas turbine combustion configuration, this can impact NO_x emissions. In the case of an ethane/natural gas blend, if the level of ethane is relatively small, the impact to NO_x emissions may be negligible. However, as the amount of ethane increases, it has the potential to significantly increase NO_x emissions, especially if a DLN combustion system is being used. If operating in a diffusion flame combustion system, some amount of diluent is always required to mitigate the high level of emissions associated with operating near stoichiometric conditions.

Evaluating Fuels

As there can be significant variation in gas and liquid fuels, it is important to understand the overall fuel composition and properties, to properly assess impacts to performance and operability. This assessment should include fuel properties, as well as determining if the fuel contains any contaminants. To determine the viability of a new fuel, a multi-step process is employed to evaluate specific fuel characteristics and properties related to combustion and fuel handling.

Step 1 – Fuel source determination

Knowing the source of a fuel, the type of fuel (gas, unrefined liquid or refined liquid), potential fuel pre-treatments, and transport logistics are key to being able to determine the applicability of a fuel for a gas turbine. If the fuel is being taken directly from a well, are there any planned pre-treatments? What contaminants might be present in the fuel that could affect gas turbine operability, performance, or component durability? How will the fuel be transported to site, and could this introduce any variation or contaminants? These questions are important to provide insights into answers for the next steps. For ethane and propane, it is important to understand if the gas will be pure or another commercial grade. For example, the HD-5 grade of propane allows for 90 percent propane with up to 5 percent propylene and 5 percent of other hydrocarbons.

Step 2 – Analytical fuel characterization

To be able to use a new fuel in a gas turbine, it is important to understand fuel composition and key properties. In the case of a gaseous fuel, a detailed listing of the percent (by volume) of each constituent gas is required to determine the heating value, Modified Wobbe Index (MWI), as well as potential risks from contaminants such as hydrogen sulfide. This information allows the fuel to be properly matched to the appropriate combustion system. Details on GE's requirements for fuel properties that should be tested, as well as suggested test methods are available in our fuel specification documents [34, 35]. After the required information has been collected, an initial determination of the applicability of the fuel can be made, and if viable, testing of specific fuel characteristics can proceed.

Step 3 – Fuel testing

The analytical examination of the fuel provides insight into combustion and fuel handling properties. This information can determine the types of tests needed to evaluate the risk of using a new fuel. Typically, these are combustion tests that focus on determining emissions, combustion dynamics (combustion acoustics), and overall operability. These tests can also be run in a variety of facilities at a variety of scales. A single nozzle combustion test facility is typically a simpler combustion system, requiring significantly less fuel, and allowing for additional instrumentation and more rapid testing. We are able to perform this type of testing at GE Global Research's primary facility in Niskayuna, NY. An example of a single nozzle combustor is shown in Figure 7; this facility has the capability of operating a full scale combustion fuel nozzle at gas turbine conditions.

Figure 7 – Single nozzle combustor at GE Global Research's facility

The next step up in scale requires a combustion chamber (for a can-annular combustor) or an annular combustor to provide insights on the behavior of the fuel in the full combustor geometry. Although these tests can provide a more complete understanding of combustor behavior on a new fuel, they require larger volumes of fuel, more time to set-up, and are therefore inherently more expensive to perform. GE is able to test fuels on a full-scale combustion chamber at full gas turbine conditions at our Gas Turbine Technology Lab (GTTL), in Greenville, SC. A full combustor test stand is shown in Figure 8. To enable fuel capability testing, the GTTL is equipped with enhanced gas blending capability (See Figure 9) to create custom fuel blends, including hydrogen, nitrogen, carbon monoxide, methane, and a variety of higher molecular weight hydrocarbons.

Figure 8 – Full combustion chamber test stand at GE's Global Research facility

Figure 9 - Fuel blending system at GE's Gas Turbine Technology Lab

Once a new fuel or a new combustion technology has been characterized and lab tested, a field validation test may be required to guide the operation in a full gas turbine with all the associated sub-systems. This type of test requires detailed coordination between the gas turbine original equipment manufacturer (OEM) and the power plant owner, and potentially the plant operator if this is a separate entity from the plant owner. Typically, a field test or field demonstration is planned months in advance to ensure that all long lead items (including fuel) will be at site, and to avoid disturbing power generation during peak periods or maintenance cycles.

GE's Gas Turbine Combustion Systems

GE offers multiple combustion systems that allow the heavy-duty gas turbine to operate on a wide variety of fuels. Our combustion systems can be separated in to two categories: diffusion and dry low NO_x (DLN). The choice of combustion system depends on the type of fuel and the application.

Diffusion flame combustors

Diffusion flame combustors are typically used for fuels with low BTU content, high hydrogen content, waste gas, ash-bearing liquid fuels, or other applications with special requirements. GE's 6B and 9E.03 gas turbines can be configured with a single nozzle diffusion flame combustor, also known as a standard combustor. GE's 7E.03 and 9E.03 units, as well as our 6F, 7F, and 9F units can be equipped with our multi-nozzle quiet combustor (MNQC), which is also a diffusion flame combustor. More than 40 F-class gas turbines have been equipped with the MNQC combustor. Figure 10 shows a typical F-class MNQC combustor head end.

Overall, GE's heavy-duty gas turbines have accumulated over 2.1 million fired hours on low BTU fuels, using diffusion flame combustors. More than 400,000 of these hours have been accumulated on F-class units with MNQC combustors, including three units with over 100,000 hours each.

Dry Low NO_x (DLN) combustion systems

DLN combustion systems are typically used for gas fuels (natural gas, LNG) and some highly refined or high quality liquids (such as distillate, naphtha, and so on). GE's 6B, 7E.03 and 9E.03 gas turbines can be configured with the DLN1 or DLN1+ combustion system. The DLN1 combustor (shown in Figure 11) has been installed on more than 870 gas turbines and has accumulated more than 28 million fired hours.

Our 6F.01 gas turbine can be equipped with the DLN2.5 combustion system, and our 6F.03 turbine can be equipped with a DLN2.6 combustor. Our DLN2.6 combustor has shipped on more than 700 6F and 7F gas turbines and has accumulated more than 27 million fired hours. The 7F.05, 9F.04, 7HA, and 9HA units are configured with the DLN2.6+ combustion system (Figure 12), which is currently installed on more than 80 gas turbines and has accumulated over 2 million fired hours. The DLN2.6+ combustor was recently installed on a 7F.05 new unit and 7F.04 field retrofit and underwent extensive field validation testing with excellent results. The DLN2.6+ also recently completed a set of validation tests on the 9HA gas turbine on GE's full speed full load (FSFL) validation facility in Greenville, SC. The DLN2.6+ combustor can be retrofitted on 7F and 9F gas turbines.

Figure 10 – MNQC combustor

Figure 11 – DLN1 combustion system

Figure 12 – DLN2.6+ combustion system

Non-Methane Hydrocarbon Capability

GE's heavy-duty gas turbines are capable of operating on a variety of fuels, including fuels with significant non-methane hydrocarbon content. This capability can be segmented into two categories: blending of hydrocarbons, and pure (hydrocarbon) fuels.

Our B and E-class turbines are capable of operating on range of gaseous fuels, including ethane and propane. Ethane or propane can be used either blended with natural gas or as 100 percent ethane in a DLN1 or DLN1+ combustion system. Our F-class turbines can operate a blend or 100 percent ethane. GE's 6F.01 and 6F.03 gas turbines with DLN2.5 and DLN 2.6 combustors, respectively, can operate with a blend of ethane and natural gas, with up to 15 percent ethane. Our 7F.05 and 9F.04 gas turbines configured with the DLN2.6+ combustion system can operate with a blend up to 25 percent ethane. These gas turbines, operating with 100 percent ethane (or other hydrocarbon) require a MNQC combustor. This capability exists for both new and previously installed units. Existing units may require updates or configuration changes for combustion and fuel accessories as well as controls. In addition, GE's 7HA and 9HA gas turbines configured with the DLN2.6+ combustion system are capable of operating on ethane blends.

GE has experience blending fuels in a variety of applications. An example is a petrochemical plant that had excess hydrogen that was blended into natural gas and used with a set of 7F.03 gas turbines configured with the DLN2.6 combustion system [36]. For this application, we provided the advanced controls and fuel blending system, including the blending hardware. The blending hardware for the gas turbines is shown in Figure 13.

Figure 13 – Fuel blending hardware at a USA site

Economic Value of Alternative Fuels

The capability of gas turbines to run on a wide variety of fuels provides developers, owners and operators a series of options when looking at the development of a new power plant or retrofit of an existing power plant. As there could be multiple fuels available, it is important to understand the relative impact of fuel cost on power plant economics. In addition to the actual cost of fuel, the ability to operate on a fuel with a lower maintenance factor, or a fuel that requires less diluent can also improve plant economics. Two metrics used to evaluate the impact of changes in fuel price are the annual fuel cost, which directly impacts annual operating expenses (OpEx), and the levelized cost of electricity (LCoE) of the plant.

Annual fuel cost

This metric is simply the change in cost to the plant when comparing multiple fuels. Although it is simple to compute, it can show how small differences in fuel cost can have a large impact on plant economics. To compute annual fuel cost, first compute the annual energy consumed by the gas turbine:

Annual energy consumed (MMBTU/yr) =

$$\frac{\text{Output (kW)} * \text{Heat Rate} \left(\frac{\text{BTU}}{\text{kWh}}\right) * \text{annual operating hours (hours/yr)}}{1{,}000{,}000}$$

From this, one can easily compute the annual fuel expense:

Annual fuel expense ($) =

$$\text{Annual energy consumed} \left(\frac{\text{MMBTU}}{\text{yr}}\right) * \text{Fuel price (\$, LHV)}$$

To determine the delta annual cost of two fuels, calculate the annual expense for each fuel, and then subtract the cost of the first from the cost of the second.

For example, let's examine the case of a 2x1 7F.05 combined cycle power plant switching from 100 percent natural gas priced at $3/MMBTU to a 25% ethane/natural gas blend with ethane priced at $2/MMBTU. This price for ethane represents a rational price change in USA regions with excess ethane supply. Figure 14 shows potential annual fuel savings versus a range of operating hours. In this case, the reduction in fuel price of $0.25/MMBTU could yield annual fuel expense savings of up to $9 million. This is a 10-year savings of roughly $91.5 million, which is equivalent to a 20-year NPV of $78 million.

As a second example, let's examine a case in which USA-sourced ethane is used instead of LNG for a power plant located in a country with a 50 Hz grid. We will assume a 2x1 9F.04 combined cycle power plant with LNG available at $12/MMBTU and ethane available at $11/MMBTU. In this case, the reduction in fuel price of $1/MMBTU could yield annual fuel expense savings of up to

$43 million, as shown in Figure 15. This is a 10-year savings of roughly $436 million, which is equivalent to a 20-year NPV of $371 million.

These two examples clearly show that even small changes in fuel prices can have a large impact on plant economics.

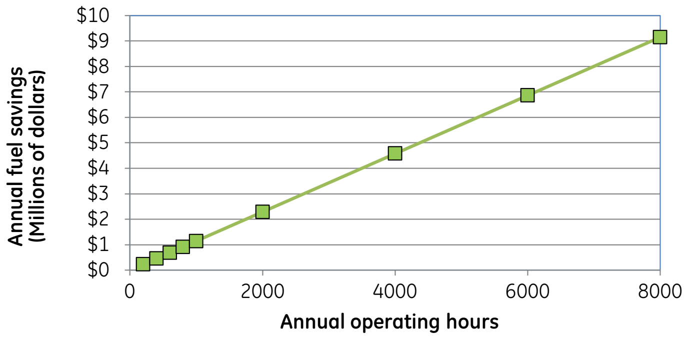

Figure 14 – Annual fuel expense savings as a function of operating hours for a 2x1 7F.05 combined cycle plant

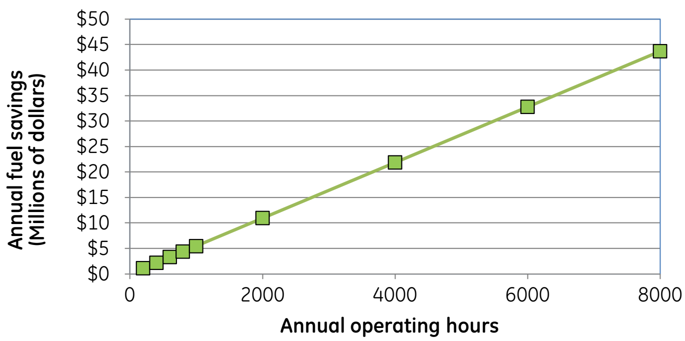

Figure 15 – Annual fuel expense savings as a function of operating hours for a 2X1 9F.04 combined cycle plant

Levelized cost of electricity (LCoE)

A second metric for examining the economic viability of a power project is the LCoE, which is defined as the per kilowatt-hour cost of building, and operating a power plant over an assumed period. Key inputs to calculating LCoE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, and financing costs.

For this case, take a look at a 1 x 9F.03 plant operating at ISO conditions that is considering switching from a fuel at $12/MMBTU to fuel at $8/MMBTU. A potential scenario that fits this example could involve a USA-sourced ethane that is available in large quantities for global power generation. The pie charts in Figure 16 show the impact of fuel on total LCoE. In both cases, fuel represents the single largest component of LCoE, which is why reducing the amount of fuel used or switching to a lower cost fuel is critical to many plant developers and owners. Traditionally, reductions in fuel expense were undertaken by increasing the overall efficiency of the power plant; however, switching to a fuel with a lower cost has the same effect.

In the base case, fuel expense accounts for 87 percent or 9.6 cents/kWh of the total cost of electricity. In the case with reduced fuel cost, the percentage is similar, at 81 percent, but the absolute amount is reduced to 6.3 cents/kWh. The change in the fuel cost reduces the fuel contribution by 3.2 cents/kWh, which is effectively the total change in the calculated LCoE. To put this into perspective, the change of 3.2 cents/kWh is roughly equivalent to a savings of $100 million per year.

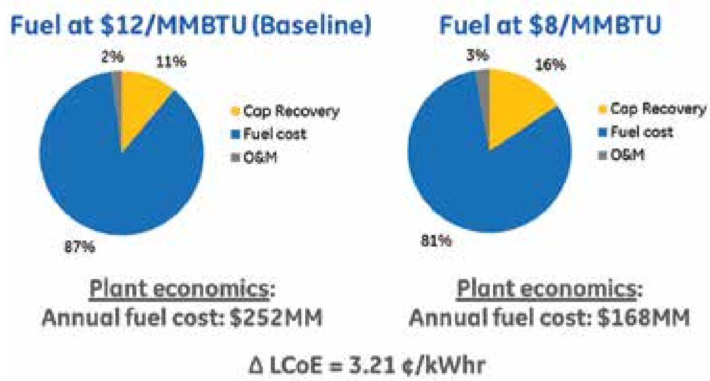

Figure 16 - LCoE impact of changes in fuel price

Conclusions

GE's heavy duty gas turbines (both new and installed units) are capable of operating on a wide variety of gas and liquid fuels, including higher molecular weight hydrocarbons. Specifically, these turbines are capable of operating on ethane and propane, as 100 percent pure gas or as blend with natural gas. (Existing units can require upgrades to yield this capability.) For some regions of the world, ethane and propane may be available in large quantities and at prices at or below those of natural gas, LNG or even distillate oil #2. When the proven fuel capability of an advanced gas turbine system is combined with reduced fuel prices, this can yield economic value for the power producer in terms of large reductions in annual fuel prices and reduced cost of electricity, which could ultimately positively impact the end user of the electricity.

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