Low NOx Emissions in a Fuel Flexible Gas Turbine

FINAL REPORT

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ABSTRACT

In alignment with Vision 21 goals, a study is presented here on the technical and economic potential for developing a gas turbine combustor that is capable of generating less that 2 ppm NOx emissions, firing on either coal synthesis gas or natural gas, and being implemented on new and existing systems. The proposed solution involves controlling the quantity of H2 contained in the fuel. The presence of H2 leads to increased flame stability such that the combustor can be operated at lower temperatures and produce less thermal NOx. Coal gas composition would be modified using a water gas shift converter, and natural gas units would implement a catalytic partial oxidation (CPOX) reactor to convert part of the natural gas feed to a syngas before fed back into the combustor. While both systems demonstrated technical merit, the economics involved in implementing such a system are marginal at best. Therefore, Praxair has decided not to pursue the technology any further at this time.

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1.0   INTRODUCTION

Developing improved combustion turbine performance with coal derived synthesis gas and developing NO_x emissions reduction technology for fuel flexible turbines has been identified as key subtopics under the High efficiency Engines and Turbines area (Strategic Center for Natural Gas). The overall objective of this program was to develop technology capable of achieving Vision 21 (V21) goals for gas turbines with design targets including fuel flexibility, near zero (2 ppm) NO_x emissions, operation with reliability and availability within the standards established for pre-1999 gas turbines and suitability for use on both new or existing turbines. These specific goals will support the V21 goal of 2 ppm NO_x emissions at the turbine exhaust at a cost significantly less than conventional backend technologies such as selective catalytic reduction (SCR).

NO_x control for turbines

It is generally accepted that NO_x is formed by three mechanisms 1) thermal NO_x, 2) prompt NO_x and 3) the $N_2O \rightarrow NO$ mechanism. For most gas turbine combustors, thermal NO_x is believed to be the dominant mechanism.

Most of the basic strategies developed to control NO_x in turbines are based on controlling the temperature to minimize thermal NO_x formation. These methods include:

1) Diluent addition: Steam, CO_2, N_2 or other diluent is added to the combustion zone of a diffusion combustor. Since NO_x formation is related to the combustion temperature the addition of diluent lowers the temperature to reduce NO_x.

2) Premixed fuel lean combustion: Typical premixed combustion mixes the fuel and oxidant upstream of the burner. Premixed combustion allows use of leaner fuel mixtures that reduce the flame temperature, and therefore thermal NO_x formation. This is the basis for DLN combustor operation.

3) Catalytic combustion: Lean premixed combustion is also the basis for achieving low emissions from catalytic combustors. These systems use a catalytic reactor bed mounted within the combustor to burn a very lean fuel air mixture. The catalyst material stability and its long term performance are the major challenges in the development of an operational catalytic combustor. Catalytic combustion is also an unlikely solution for retrofitting existing turbines.

4) Post combustion treatment: NO_x can be removed from the gas turbine exhaust utilizing ammonia injection and SCR catalyst that converts NO_x to molecular nitrogen. Conventional SCR technology operates in a narrow temperature range (288C-399C). The equipment is comprised of segments stacked in the exhaust duct. Each segment has a honeycomb pattern with passages aligned to the direction of the flow. A catalyst such a vanadium pentoxide is deposited on the surface of the honeycomb. SCR systems are sensitive to fuels containing more than 1000ppm sulfur. For a GE turbine MS7001EA an SCR designed to remove 90% of the NO_x has a volume of 175 m^3 and weights 111 tons. The cost of the system, the efficiency penalty due to the pressure drop introduced by the catalyst, and the potential for NH_3 slip are the major disadvantages of this system.

The technology that was to be developed under this program was built on the concept that a combustor could be developed that was capable of achieving the above referenced goals when oper-

ated on fuels with specific properties. An integrated fuel processor would control fuel properties to keep them within the envelope required for targeted performance. The use of such a combustor would eliminate the need for post combustor treatment systems and the associated penalties. Should the concept be successful it would be applicable to new Integrated Gasification Combined Cycle (IGCC) plants as well as new Natural Gas Combined Cycle (NGCC) plants and retrofits to existing NGCC plants.

   This report summarizes the work that was done under Phase I of a three phase program. Phase I work focused on concept development of a fuel flexible combustor, a fuel processor scheme capable of working with coal derived fuel gas and hydrogen/natural gas blend as well as a techno-economic comparison of the concepts identified relative to alternative end of pipe solutions (e.g., SCR).   The results of the above analysis will be summarized in the following order: (i) fuel processor scheme, (ii) conceptual combustor design and integration of the combustor with the fuel processor and finally (iii) process and economic analysis comparing the conceptual design with the option of installing an SCR.

2.0   EXECUTIVE SUMMARY

The overall objective of this report was to identify potential gas turbine based system designs that would be capable of generating less than 2 ppm of NO_x emissions while fired on coal synthesis gas or natural gas. This new gas turbine combustion system must also cost significantly less than conventional back-end technology such as selective catalytic reduction (SCR). The solution presented herein involves the modification of the fuel supply to the gas turbine in terms of the hydrogen content. The presence of H_2 in the fuel, increases the reactivity of the system leading to higher flame speeds and increased flame stability. By adding H_2 to natural gas or modifying the H_2 content of a coal synthesis gas, the combustor may be operated at a lower temperature, thus producing less thermal NO_x and the increased reactivity of the fuel also allows for nearly complete CO burnout.

The hydrogen content of the fuel supply to the gas turbine will be modified depending on the fuel source. In the case of a coal synthesis gas unit, a water gas shift converter would be utilized to adjust the H_2 content to the desired level. Natural gas fired units would be supplied H_2 from a catalytic partial oxidation (CPOX) reactor. In this scenario, a slipstream of natural gas would be input to the CPOX unit to create a H_2 containing syngas, which would then be recombined with additional natural gas for the gas turbine combustor. For either a coal gas or natural gas fired unit, the combustor would be based on a lean premixed system with minor modifications to the fuel nozzles based on the fuel input.

The economics of implementing this new gas turbine combustor was compared to two baseline cases: 1) an integrated gasification combined cycle (IGCC) power plant and 2) a natural gas combined cycle (NGCC) power plant both with SCR units for NO_x clean-up. By changing the combustion system to the proposed fuel flexible system involving H_2 addition/modification to the fuel, some economic advantages were realized. In the case of the IGCC plant, the capital cost of a new facility was lowered by ~1% and the operating cost was decreased slightly. The modification of a NGCC facility with a CPOX based system resulted in marginal cost and operating savings. At this time, the modest gains of the IGCC facility compounded with the small market potential do not justify further activity by Praxair in pursuing this technology. NGCC facilities have a large market potential that IGCC plants, but the economic advantages of developing a CPOX based combustion system are not sufficient enough to warrant further consideration at this time.

3.0   FUEL PROCESSOR SCHEME

The purpose of this task was to define requirements and economic alternatives that will permit us to supply the turbine with a hydrogen containing gas. In the case of a natural gas turbine pure H_2 is too expensive to use as a fuel-blending component. In the case of an IGCC turbine provisions must be made to alter the fuel to a composition that is compatible with the gas turbine combustor. In each a fuel processor is needed that will 1) adjust the composition of IGCC fuel gas as needed or 2) produce a crude synthesis gas stream with sufficient H_2 content to blend with natural gas. Traditional H_2 production systems such as steam methane reforming (SMR), autothermal reforming (ATR) and partial oxidation (POX) based reforming were considered together with novel H_2 generation systems currently under development at Praxair and outside Praxair. The results of this analysis are provided below.

Coal Gas Fuel Processor

Table 1 depicts some representative coal gas compositions from different types of gasifiers currently available. From Table 1 we observe that coal gas contains significant amount of hydrogen and may contain a substantial quantity of carbon monoxide as well. It can be also noted that there is significant variability in the gas composition.

Table 1. Coal gas composition examples

Constituent (dry basis)	Shell Gasifier	Texaco Gasifier	Air Gasifier
H_2	31.3	34	23
CO	62.7	49	7
CO_2	1.5	9.7	20
N_2	4.5	6.1	47
CH_4		0.2	3
LHV [MJ/ m^3(BTU/scf)]	10.7 (287)	9.4 (251)	4.2 (113)

As discussed earlier, the role of the fuel processor is to provide the combustor with a fuel containing a stable hydrogen content and composition. This can be accomplished by shifting part of the CO with a water gas shift reactor. Water gas shift reactors operate by reacting CO and steam to form H_2 and CO_2 according to the general reaction:

$$CO + H_2O = CO_2 + H_2$$
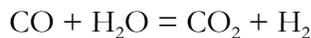
Water gas shift operates at 200-400C temperatures and high pressures and a catalyst has to be used. A variety of catalysts are available from several catalyst manufacturers. Depending on the desired composition, operating conditions and an appropriate catalyst can be selected and sized. Praxair has significant experience in the design and operation of these units since they are a standard

component of hydrogen production plants. The exact details of the composition will need to be determined from turbine combustion rig tests.

Natural Gas Fuel Processing

Since H_2 is a key component of our conceptual solution, fuel processing (H_2 production with natural gas) methods were analyzed to determine an economic method of supplying the required H_2 and/or controlling the H_2 content of the fuel. H_2 production is practiced on large scale but the cost of pure H_2 is prohibitive when using it as a fuel additive in the required quantities (5-20% of fuel volume see Table 2).

An analysis of primary hydrogen producing technologies was conducted to identify the most cost effective technology for this application. Ideal characteristics of the hydrogen production process include low capital cost (<\$.75MM) and low operating cost in order to compete with selective catalytic reduction process (e.g. for a 40MW turbine SCR has a cost of about \$1MM).

Table 2: Hydrogen requirements for various gas turbine sizes

GT Size (MW)	NG (Nm^3/h)	VOLUME H_2 (Nm^3/h)		
		5 vol.% H_2	10 vol.% H_2	20 vol.% H_2
5	1,363	68	136	205
25	6,817	341	682	1,023
40	10,907	545	1,091	1,636
80	21,813	1,091	2,181	3,272
100	27,267	1,363	2,727	4,090

The three major commercial processes for syngas production in operation today are: steam methane reforming (SMR), non catalytic partial oxidation (POX), and autothermal reforming (ATR). SMR is the most widely used technology for on-purpose H2 production. Approximately 20% of the natural gas used in steam reforming is burned to produce sufficient heat to reform the remaining fuel with steam. This results in significant CO2 and NOx emissions. Steam reforming is practiced at high pressures (>300psi) and produces a syngas containing 3-6:1 H2:CO ratio. POX, as typified by the Texaco Gasification Process, introduces natural gas, oxygen, and steam into the reactor by means of a specially designed burner. No catalyst is present in the reactor and the reaction is purely homogeneous. Oxygen is consumed at the reactor entrance to form steam, CO2, and heat which, in the main reactor, are used to reform the remaining methane. The residence time in the reactor is about 1-4 seconds. The raw syngas that is produced by POX contains a 1.8:1 H2:CO ratio. ATR combines partial oxidation and steam reforming to produce synthesis gas. Sulfur free natural gas is mixed in a burner with oxygen, steam, and optionally a recycle stream containing CO2. The O2 is consumed in this first reaction zone. The hot gas from the burner is fed to a reforming catalyst bed below the burner where the final equilibration takes place. The raw syngas contains a CO:H2 ratio close to 2.3:1 without CO2 recycle or close to 2:1 with CO2 recycle. ATR needs less steam than SMR (0.6:1 steam/methane ratio in the reactor feed). Residence times in the reactor are 2-3 sec. In recent years there has been considerable work in the academia on Catalytic Partial Oxidation

(CPOX) with high temperature, short reaction time catalysts. By operating at high temperatures, reaction time can be greatly reduced and the required reactor size and associated capital cost shrink dramatically. This technology is applicable to highly exothermic oxidation reactions where the heat generated by reaction, provides an immediate heat source such that heat transfer is neither the rate-limiting step nor the high-cost step. Schmidt and coworkers pioneered this work [Hickman and Schmidt (1992)] at the University of Minnesota using highly reactive monolith reactors coated with Pt or Rh and have reported greater than 95% H2 and CO yield from methane and air or oxygen at atmospheric pressures. The reaction rates were on the order of a millisecond, no steam was used, and the syngas produced had a 2:1 H2:CO ratio. We performed preliminary technical and economic analysis to compare the three existing technologies and also we estimated the cost of a process based on catalytic partial oxidation of natural gas with air (CPOX).

ATR and POX are typically used when synthesis gas with a low H2:CO ratio is needed. POX is also used with lower quality fuels such as coal and petroleum coke. ATR and POX generally utilize pure O2, which is not routinely available in sites associated with gas turbines. In internal studies at Praxair the cost of hydrogen production with these technologies has always been higher than the cost of an SMR. ATR and POX are unlikely candidates for this application because of the cost and the O2 requirement and thus were not evaluated further.

Table 3 summarizes the various properties of the hydrogen production technologies considered as part of this work.

Table 3: Hydrogen production technology comparison

Process	H_2:CO	Steam Requirement	Residence time	O_2 required	Catalyst required	N_2 present
SMR	3-6:1	high	seconds	no	yes	no
POX	1.8:1	moderate	seconds	yes	no	no
ATR	2-2.3:1	moderate	seconds	yes	yes	no
CPOX	2:01	none	milliseconds	no	yes	yes

SMR is based on large furnaces, requires large amounts of steam and also produces NOx. SMR is the preferred method for large-scale hydrogen production. CPOX is a simple process that requires passing of air and natural gas over a precious metal catalyst at very high space velocities. The process has not been commercialized at the required scale. We estimated that CPOX could produce hydrogen for mixing with natural gas at 30-70% discount over SMR. Figure 1 illustrates the normalized cost to produce H2 as a function of gas turbine size, when using either SMR or CPOX as the means of H2 production.
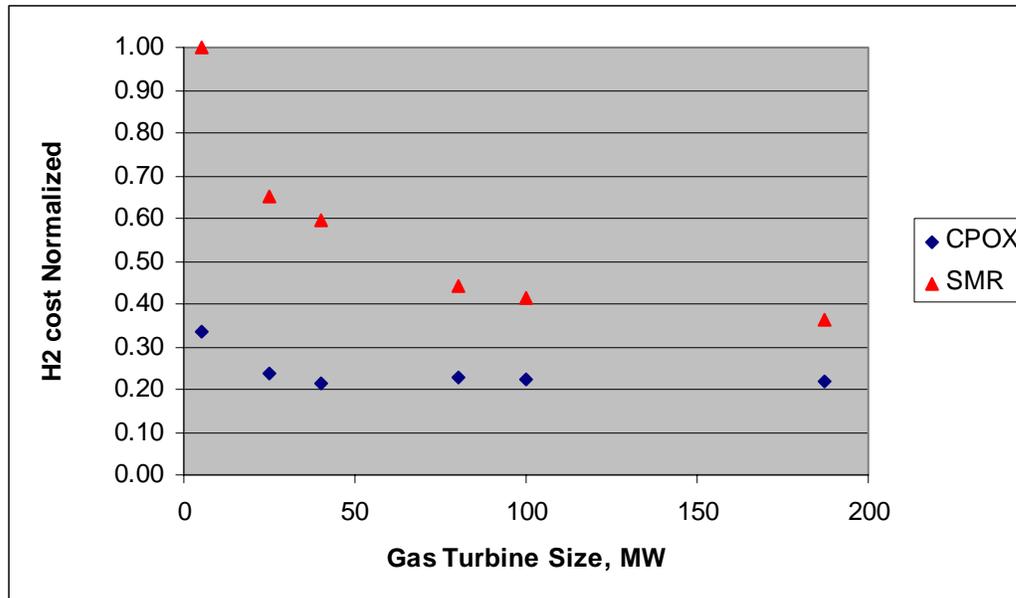
Figure 1. Contained hydrogen unit cost comparison (includes capital and operating cost)

4.0   CONCEPTUAL DESIGN OF FUEL FLEXIBLE GAS TURBINE COMBUSTOR

Hydrogen and H_2-enriched fuels demonstrate substantial different combustion characteristics than hydrocarbon based fuels (e.g., natural gas). When H_2 is added to a fuel, it affects various attributes including the physical nature of the flame, flame stability, combustion efficiency, and emissions. The dramatic effect on the combustion process due to H_2 is mainly related to the increased reactivity of H_2 compared to other fuel gases. The flame speed of a stoichiometric H_2/air flame is approximately 200 cm/s compared to the equivalent methane/air flame which has a flame speed of ~40 cm/s. Hydrogen also affects the radical pool in a flame, thus the rate of oxidation of other fuel species is impacted.

The addition of H_2 to the fuel of a gas turbine combustor has two main benefits. First, the lean blow out (LBO) limit is extended to lower equivalence ratios. Second, the addition of H_2 increases the rate of CO oxidation resulting in lower CO emissions. These two benefits allow the combustor to operate at a lower temperature, thus reducing production of the thermal NO_x.

The affect of H_2 on the extinction of flames has been observed for both diffusion and premixed flames. Karbasi and Wierzba (1998) experimented with jet diffusion flames of co-flowing natural gas and air. They found that by adding up to 25% H_2 to the fuel, the fuel velocity at blow out was increased by a factor of three. Ren *et al.* (2001) suggested that flame speed and flammability limits alone are not the best measures of the combustion enhancements due to H_2 addition because of the importance of fluid mechanics effects in systems such as gas turbine combustors. They examined methane/hydrogen premixed flames in a stagnation flow configuration, and found that the extinction strain rate was substantially increased by adding only 8% H_2 to the fuel. Schefer (2003) also found that the lean blow out of swirl-stabilized premixed methane/air flames was impacted by the

addition of H_2. Schefer's (2003) results indicate that the addition of H_2 serves to stabilize the flame at lower equivalence ratios and increased flow rates.

The enrichment of hydrocarbon fuels with H_2 has been seen to lead to lower CO levels in combustion exhaust at equivalent NO_x readings. High pressure diffusion combustor tests performed by Maughan *et al.* (1993) demonstrated a decrease in CO with the addition of H_2 to natural gas at a given temperature. Phillips and Roby (1999) also observed reduced CO emissions in a premixed combustor for a given NO_x level for a natural gas fuel containing 10% H_2 by volume. This was attributed to an increase in the radical pool (i.e., H, O, OH) due to the presence of H_2. Schefer (2003) confirmed that the quantity of OH radicals in a premixed, swirl-stabilized methane/air flame is indeed increased as H_2 is added into the fuel (up to 20% by volume). The presence of additional OH radicals is likely to enhance the oxidation of CO in the flame, resulting in lower emissions.

H_2 addition to the fuel intensifies the local energy release through the increased concentration of intermediate energetic OH^- radicals. Although this does not have a substantial effect on NO_x, it does have a significant effect in improving flame stability and reducing CO formation. Typically NO_x reduction in combustors is achieved by reducing flame temperatures. However, as the flame temperatures are reduced, portions of the combustion reaction freeze and remain incomplete, generating substantial quantities of CO. The addition of H_2 reduces CO due to the increased intensity of local heat release, thus allowing a decreased flame temperature and lower NO_x production.

Hydrogen containing fuels have previously been demonstrated in large-scale gas turbine combustors. Hydrogen enriched natural gas (up to 12% by volume at base load) was utilized in a frame 9E gas turbine with a DLN-1 combustion system in premixed mode [Morris *et al.* (1998)]. The tests at base load showed no appreciable change in NO_x and CO decreased as H_2 was added to the fuel. The major concern of operating in a premix mode with H_2 enriched fuel is flashback. The elevated flame speed and increased reactivity caused by H_2 can cause the flame to stabilize upstream of the main combustion chamber and burn out hardware. Traditionally, this problem has been overcome by employing a diffusion combustor, such as in IGCC systems in which the resulting syngas contains primarily H_2 and CO, with no appreciable hydrocarbons. Tests on these coal gas based fuels have shown that with the addition of diluents such as N_2, CO_2, or steam, NO_x can be dramatically reduced [Battista and Dudley (1994)].

Combustor Development

Gas turbine combustors are grouped in two general categories, diffusion and premixed [Lefebvre (1999)]. In a diffusion combustor, fuel and air are separately injected into the combustion zone where they mix and combust while in the premixed system, fuel and air are first mixed and then ignited in the combustion zone. The main advantage of the diffusion style combustor is flame stability, thus liquid fuels and gaseous fuels with high flame speeds (e.g., coal gas) can be burned in such a system. The drawback of diffusion based systems is that the flame zone temperature is inherently higher than a premixed system, and substantial quantities of NO_x are produced. The flame temperature is decreased by injecting diluents, such as steam, into the flame region to promote mixing. However the mixing is incomplete, thus the flame temperatures can not be lowered to the same level as a premixed system. Premixed systems can be operated at a much lower equivalence ratio such that the flame temperature throughout the system is decreased and thermal NO_x production is de-

creased compared to a diffusion system. The disadvantage of premixed systems is flame stability, especially at low equivalence ratios. Also, there is a tendency for the flame to flashback. The ability of the flame to flashback is increased as the flame speed of the fuel increases.

The main objective of this study was to investigate the prospect of designing a fuel flexible gas turbine combustor that produces less than 2 ppm NO_x, and may operate on a hydrogen enriched natural gas, or with minor modifications burn a coal gas based fuel. The gas turbine combustor that could achieve these goals will be operated as a premixed combustion system. However, two difficulties exist in implementing a premixed system that operates with both natural gas and coal gas. First, in order to achieve the low NO_x emissions level required, the system must operate leaner than machines currently operate. Second, as H_2 is added to the fuel, the tendency to flashback due to a higher flame speed is increased. Figure 2 illustrates the effect of H_2 content on the calculated laminar flame speed for hydrogen enriched methane and for coal gas with increasing amounts of diluent N_2 (equivalence ratio of 0.7). As H_2 is added to methane, the calculated flame speed increases slightly up to a 50:50 mixture of H_2 and methane. Beyond this H_2 content the flame speed increases much more rapidly. The model coal gas considered in this report (40% H_2, 51% CO, 8.5% CO_2, and 0.5% H_2O), has a laminar flame speed of approximately 48 cm/s in its raw form, but the flame speed drops considerably as diluent N_2 is added. At about 50% N_2 addition, the flame speed is comparable to that of pure methane which indicates that with sufficient diluent, the chance of flashback with natural gas may not be much different than pure natural gas.

One embodiment of a gas turbine system capable of burning hydrogen enriched natural gas is illustrated in Figure 3. The system consists of the gas turbine, an external air compressor, and a catalytic partial oxidation (CPOX) reactor. When the turbine combustor is operating on natural gas, a portion of the natural gas is supplied to the CPOX reactor along with air from the external compressor. The output from the CPOX unit is a crude syngas containing mainly H_2, CO, and N_2. The syngas is recombined with the natural gas in the fuel bypass and delivered to the gas turbine combustor. Also, a portion of the air from the external combustor may bypass the CPOX unit and be directly delivered to the combustor to supply additional diluent if necessary. The amount of H_2 in the fuel can be adjusted to result in improved flame stability such that the combustor can operate at a lower temperature and decrease NO_x production.

A gas turbine burning coal gas no longer requires the CPOX reactor since it will contain sufficient quantities of H_2 to keep the flame stable at low equivalence ratios. Also, the external air compressor is not needed due to sufficient quantities of diluent present in the fuel (i.e., N_2). Thus, the only major change to the combustor would be alternate fuel nozzles to accommodate the increased volume of fuel flow.

Combustor Modeling

A series of global models were developed to study the effect of various H_2 containing fuels on gas turbine emissions. The models consist of a network of perfectly stirred reactors (PSR) and plug flow reactors. The chemical kinetics inside the reactors is represented by the natural gas combustion mechanism, GRI-Mech 3.0 [Smith *et al.* (1999)]. The models were solved using the CHEMKIN III computer software (Reaction Design, Inc.). One of the prospective models is illustrated in Figure 4. Fuel and air are first mixed in a non-reacting chamber. The mixture is then introduced to the first
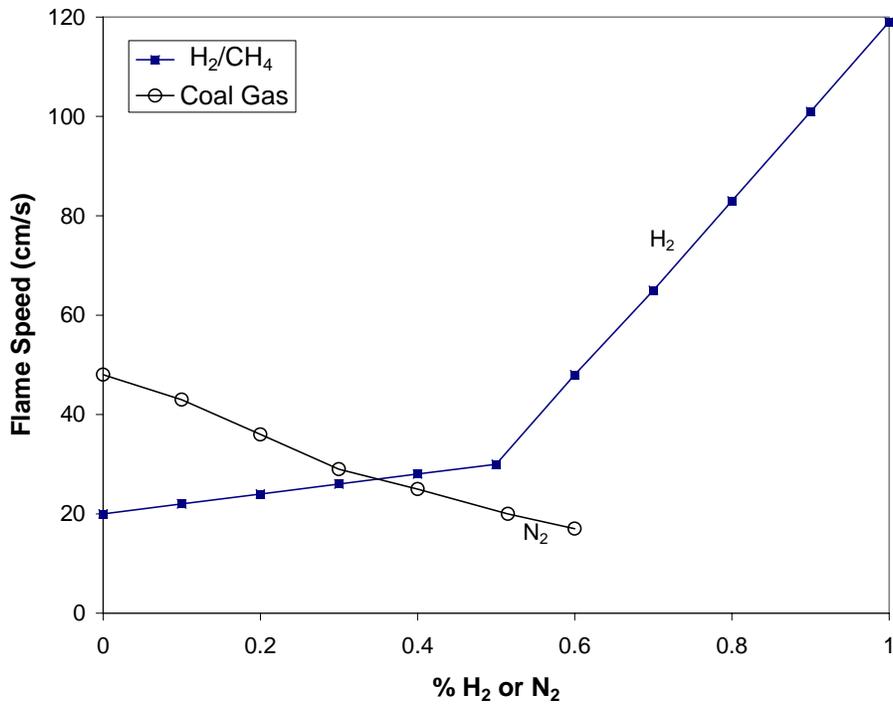
Figure 2. Calculated laminar flame speed versus the volume percent of H_2 in methane or the volume percent N_2 addition to the model coal gas (equivalence ratio = 0.7).
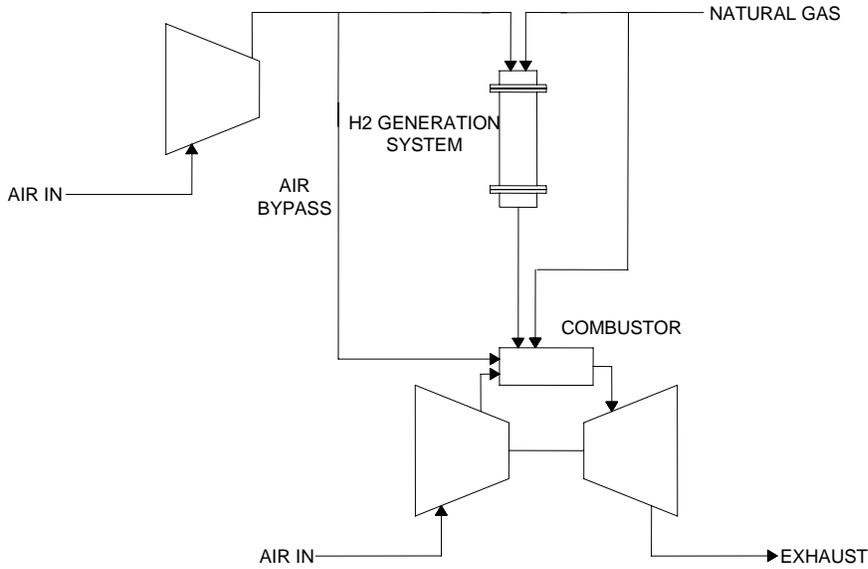

Figure 3. Low NO_x gas turbine system capable of burning hydrogen enriched natural gas.

PSR in which the mixture is ignited. The products move on to a second reactor where more air may be added, followed by a plug flow reactor to serve as a burn-out region.

This model was fit to experimental data for NO_x and CO from an independent project. In order to fit the data for natural gas, the volumes of the reactors were varied depending on the fuel-air ratio. Upon switching to a H_2 containing fuel, the existing model developed for natural gas was no longer valid. This indicates that H_2 containing fuels have a direct impact on the shape and size of the flame in the combustor. Experimental data demonstrates that at a given NO_x level, the CO emissions are reduced by the addition of H_2, while the model indicates that there would be virtually no change by switching to a H_2 containing fuel. The model parameters were adjusted to reproduce data for H_2 containing fuels, but the results did not indicate a relationship between reactor size and H_2 content. This exercise was repeated for various model embodiments with the same result.
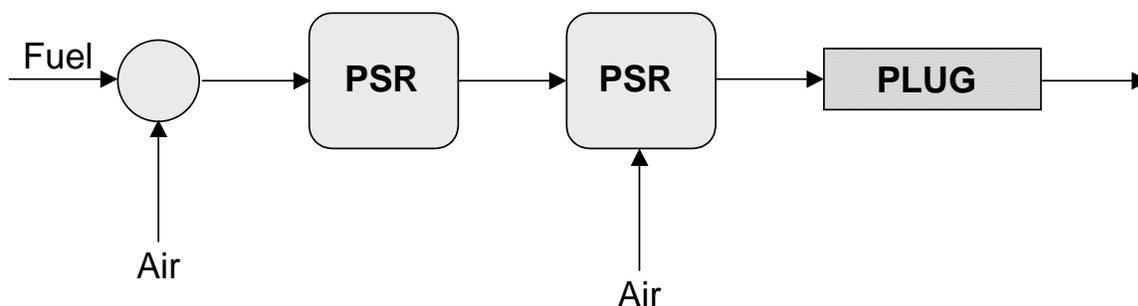

Figure 4. Example of a reactor network model utilized to study gas turbine combustor emissions.

The difficulty encountered in applying models like the one proposed in Figure 4 can be attributed to a change in the flame structure as the H_2 content of the fuel is changed. Previous work has shown that flames become shorter, more stable, and result in greater radical concentrations as H_2 is added to a hydrocarbon fuel [Choudhuri and Gollahalli (2000), Schefer *et al.* (2002), Schefer (2003)]. This change in flame shape subsequently changes the residence time distribution in the system, thus the model for the reactor network is also modified as the fuel composition changes. The combustion zone of a gas turbine is a complex 3-D structure that is very difficult to predict from the simple 3-node model illustrated in Figure 4. The conclusion was reached that a reactor network model is insufficient to describe combustion in the gas turbine with various fuels. Future work should focus on understanding how various fuel mixtures affect flame structure, and the extension of flame structure to a zone-type combustor model.

5.0   PROCESS AND ECONOMIC ANALYSIS

As discussed above, the 2 ppm fuel flexible combustor could operate on coal-derived synthesis gas in an IGCC plant, or on H_2-enriched natural gas in a NGCC plant with a CPOX reactor. In either mode, to be considered a viable NO_x reduction technology, the fuel flexible combustor offerings must provide an economic advantage over comparable baseline technologies. In this section,

the baseline and fuel flexible combustor processes are described in detail, and the results of the IGCC and NGCC comparative economic analyses are presented and discussed

IGCC and NGCC Baseline Processes

The baseline for coal gas operation, depicted schematically in Figure 5, was a newly installed IGCC plant based on a GE 7241FA gas turbine with a diffusion combustor. Slurried Illinois #6 coal was fed to an O_2-blown Destec (now ConocoPhillips) gasifier operating at 1370 C (2500 F) and 30 bar [30 bar (435 psia)]. The raw syngas from the gasifier was subsequently cooled to 370 C (700 F) against HP steam generation and partly recycled to the gasifier for quenching. The unrecycled raw syngas was then processed in a scrubber and COS hydrolysis unit, and subsequently cooled to 38 C (100 F) against desulfurized syngas, steam turbine condensate, and trim cooling water. After conventional H_2S removal (e.g. MDEA, Selexol) the clean syngas was reheated to 260 C (500 F) against raw syngas and HP BFW from the HRSG before being fed to the gas turbine. The three-pressure HRSG produced nominally 1.7 (25), 15 (220) and 110 (1600) bar (psia) steam for use in the deaerator and condensing steam turbine. The steam turbine had high [103 bar (1500 psia)] and intermediate [14 bar (200 psia)] pressure inputs, reheat following the high pressure stage, and a condenser pressure of 0.14 bar (2 psia).

For improved integration with the gas turbine, the cryogenic air separation unit (ASU) operated at an elevated pressure of 13.4 bar (195 psia). About 42% of the required air for the ASU was extracted from the discharge of the gas turbine compressor, while the balance was provided by an external compressor. Product O_2 at 10 bar (145 psia) was compressed to 38 bar (550 psia) and delivered to the gasifier, while the product N_2 streams at 4 (60) and 13 (190) bar (psia) were adiabatically compressed to 22 bar (320 psia) and routed to the gas turbine for NO_x reduction and power augmentation. In this configuration, the diffusion combustor achieved roughly 9 ppm NO_x, and so still required an ammonia-based SCR installed in the downstream HRSG to meet the 2 ppm NO_x target. The gross and net plant outputs were 313.3 and 273.5 MW, respectively, with a net LHV plant efficiency of 42.2%.
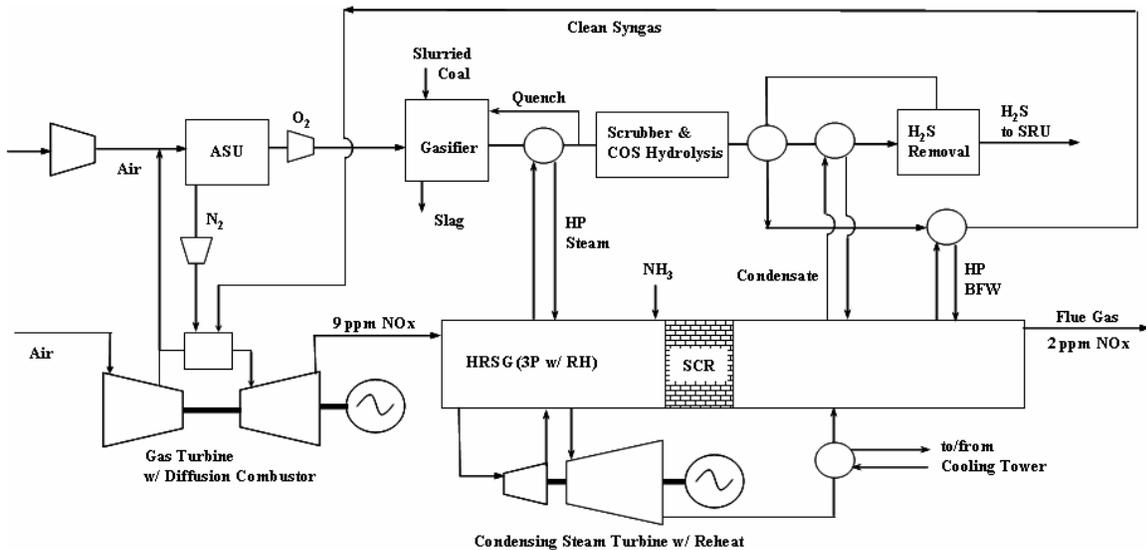

Figure 5. Baseline IGCC plant with diffusion combustor and SCR

An analogous baseline was then defined for natural gas operation, as shown in Figure 6. This newly installed NGCC plant was based on a GE 7241FA gas turbine with an advanced premixed - or DLN - combustor, capable of achieving 8 ppm NO$_x$. Again, an ammonia-based SCR was required in the downstream HRSG to meet the 2 ppm NO$_x$ target. Like the coal gas baseline, the HRSG design produced nominally 1.7 (25), 15 (220) and 110 (1600) bar (psia) steam for use in the deaerator and condensing steam turbine. The steam turbine had high [103 bar (1500 psia)] and intermediate [14 bar (200 psia)] pressure inputs, reheat following the high pressure stage, and a condenser pressure of 0.14 bar (2 psia). The net plant output was 239.5 MW, with a net LHV plant efficiency of about 52%.
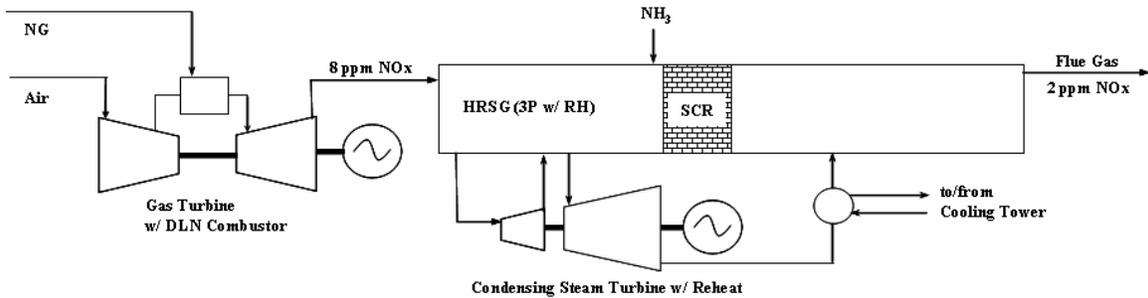

Figure 6. Baseline NGCC plant with DLN combustor and SCR

Fuel Flexible IGCC and NGCC Processes

As discussed earlier in the combustion section for coal gas operation, replacing the diffusion combustor with the fuel flexible combustor decreased gas turbine NO$_x$ to 2 ppm with minimal additional combustor pressure drop, thus enabling the elimination of the SCR (see Figure 7).
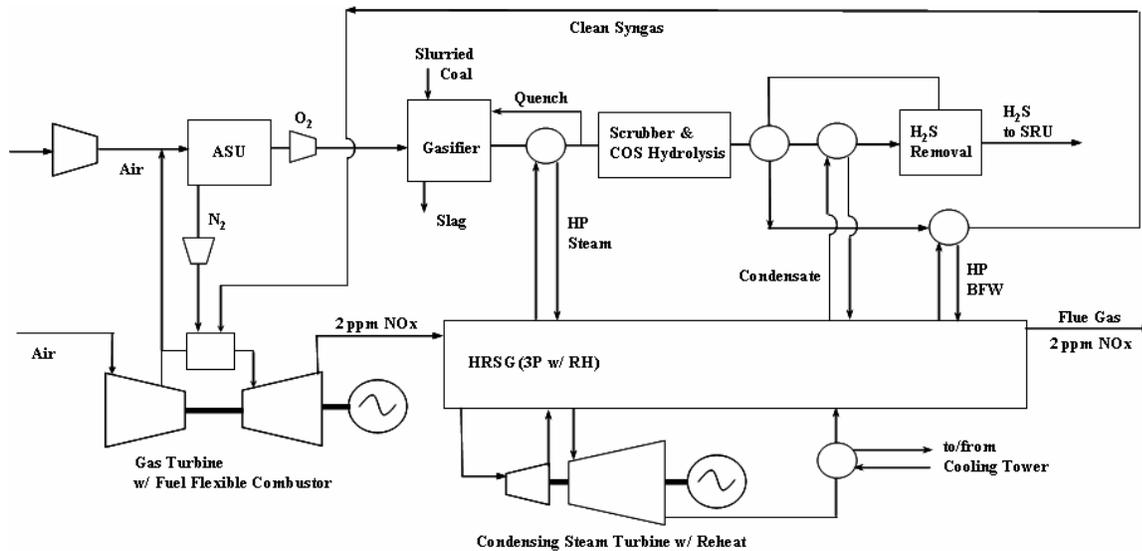

Figure 7. IGCC plant with fuel flexible combustor

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To achieve 2 ppm NO_x with the fuel flexible combustor for natural gas (NG) operation, part of the NG feed was converted to syngas in a CPOX reactor. As depicted in Figure 8, both compressed air and a slipstream of NG (less than 3% of the total) were fed to the CPOX, which generated syngas at 21.7 bar (315 psia) and 815 C (1500 F). The syngas was immediately quenched to 200 C (400 F) by demineralized water from the HRSG, and was subsequently fed to the gas turbine. This quenched syngas has a low heating value [4.3 MJ/st. m^3 (116 BTU/scf) LHV], containing roughly 20vol% H_2. Thus, while the syngas accounted for over 16% of the gas turbine fuel stream on a volumetric basis, it only represented 2.5% of the heat input to the system.

Both the baseline and fuel flexible combustor cases were modeled at ISO ambient conditions [1bar (14.7 psia), 15 C (59 F), 60% RH] using Thermoflow's GTPRO software. GTPRO allows for the detailed evaluation of gasification trains, gas turbines, HRSGs, and steam turbines, based on up-to-date vendor performance information. The CPOX system was modeled using AspenTech's HY-SYS process simulator.
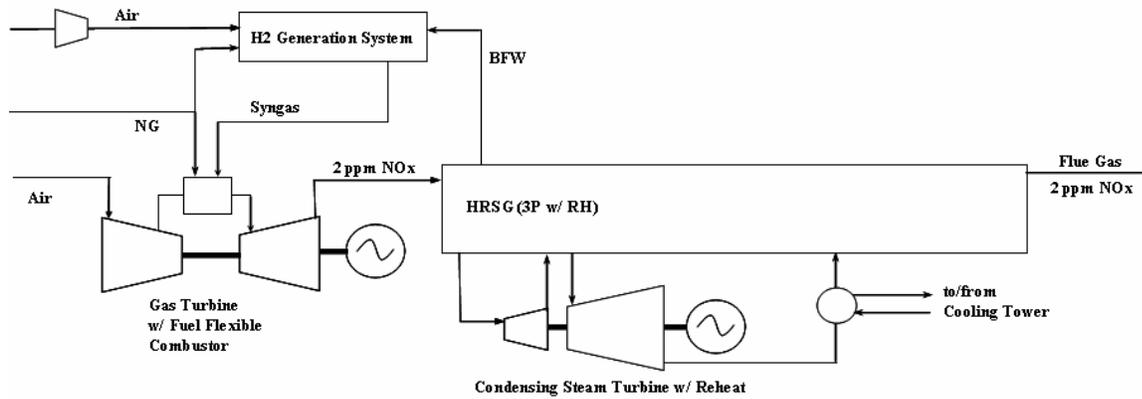

Figure 8. NGCC plant with fuel flexible combustor and CPOX

Evaluation of SCR Costs

In either coal gas or natural gas operating mode, the key benefit of the fuel flexible combustor was avoidance of the capital and operating costs associated with a SCR. Table 4 quantifies these SCR costs on an annual basis for the 7FA NGCC plant, assuming a 94% on-stream factor and $35/MWh power. The new installed cost of a SCR and associated ammonia system was estimated at $1.65MM ($1MM for catalyst, $0.65MM for the ammonia system). Furthermore, SCR catalyst required replacement every 6 years for $1MM. Table 4 SCR catalyst replacement cost includes both initial and replacement catalyst costs amortized at 8% every 6 years. The remaining $0.65MM of initial capital was annualized using a simple 24%/yr capital recovery factor. Purchased NH_3 at $0.10/lb was assumed, though this did not include the less tangible issues of on-site NH_3 storage and handling. By backpressuring the gas turbine by roughly 700 Pa (0.1 psia), the SCR decreased gas turbine power output, and NH_3 distribution pumps and blowers further increased parasitic loads. Note that over 80% of the $460k annual cost was related to initial or replacement capital.

Table 4: Annualized SCR cost breakdown for the 7FA NGCC plant

	Annual SCR Costs
Reduced Power Output	$0.035 MM
NH$_3$ Usage	$0.029 MM
Other	$0.028 MM
SCR Catalyst Replacement	$0.216 MM
Annualized Capital	$0.156 MM
Total	$0.464 MM

IGCC Comparative Economics

IGCC economics for the baseline vs. fuel flexible combustor case were evaluated using GTPRO's capital and operating cost estimation package, PEACE. The fuel flexible combustor was assumed to add no incremental capital to the new IGCC plant vs. the diffusion combustor. Other economic assumptions included a 30 year plant life, 70% debt financing at a 9% rate over a 15 year term, an overall tax rate of 42%, and 15% straight line depreciation. An initial coal price of $0.0012/MJ ($1.30/MMBTU) LHV was escalated annually at 1% vs. a 3% assumed inflation rate. Power prices were escalated at 3% annually. Finally, the single-train plant was assumed to have an on-stream factor of 88%. Based on these economic assumptions, Table 5 presents the key outputs for both cases, including net plant power and efficiency, plant cost, and the first year cost of electricity corresponding to a 15% return on equity.

Table 5: Comparative IGCC plant economics for the baseline diffusion combustor (with SCR) and fuel flexible cases

	Diffusion	Fuel Flexible
Net Power Output (MW)	273.50	273.83
Net LHV Efficiency (%)	42.24	42.32
Plant Cost ($MM)	444.67	440.91
Specific Plant Cost ($/kW)	1626	1610
Initial COE @ 15% ROE ($/MWh)	42.0	41.7

As shown in Table 5, elimination of the SCR in the fuel flexible case resulted in both a slight decrease in plant cost (about $4MM or 1%) and a slight increase in plant efficiency (0.08%), mainly due to the decreased HRSG pressure drop. Power output increased by 0.1%. The combined effect was to lower the plant's COE by $0.3/MWh. For a 275 MW plant, this translates to over $630k annually.

NGCC Comparative Economics

PEACE could not be used to generate comparative economics for the NGCC DLN and fuel flexible combustor cases, as GTPRO could not model the CPOX reactor. Therefore, budgetary cost estimates were made for CPOX-related equipment (i.e. reactor, quench vessel, air compressor and auxiliaries) based on historical quotes. Installation, engineering and contingency factors were applied to obtain total installed cost. Installed capital costs were then annualized using a simple capital recovery factor – 24%/yr for the non-catalyst SCR equipment and 27.6% for all CPOX related equipment. Other assumptions included $0.0038/MJ ($4/MMBTU) HHV NG, $0.53/m^3 ($2/mgal) demin water, and $0.22/kg ($0.1/lb) NH$_3$. Table 6 compares the annualized cost advantage of the fuel flexible combustor with CPOX case over the baseline DLN with SCR case for power prices of $35 and $48/MWh and for 94% and 50% on-stream factors.

Table 6: Itemized annual cost advantage of fuel flexible case over DLN case at specific power prices and on-stream factors (OSF)

OSF (%)	94	94	50	50
Power Price ($/MWh)	48	35	48	35
Natural Gas	-$0.350 MM	-$0.350 MM	-$0.186 MM	-$0.186 MM
Power	+$0.519 MM	+$0.379 MM	+$0.276 MM	+$0.201 MM
NH$_3$ + Demin Water	+$0.017 MM	+$0.017 MM	+$0.009 MM	+$0.009 MM
Catalyst	+$0.200 MM	+$0.200 MM	+$0.200 MM	+$0.200 MM
Capital	-$0.338 MM	-$0.338 MM	-$0.338 MM	-$0.338 MM
Total	**+$0.048 MM**	**-$0.092 MM**	**-$0.039 MM**	**-$0.114 MM**

As indicated by Table 6, high on-stream factors and power prices are required for the fuel flexible combustor to achieve any advantage vs. the baseline DLN combustor with SCR. Even then, the advantage ($48k/yr) is marginal. The fuel flexible case generated 0.55% greater net power than the 239.5 MW baseline, but consumed 0.6% more NG, resulting in a 0.03% loss in efficiency. When power prices were sufficiently high (i.e. >$43.6/MWh), the revenue from the additional power output offset other losses to create a net advantage for the fuel flexible case. However, for $35/MWh power, this advantage disappeared. The constant catalyst cost advantage for the fuel flexible case

reflected annualized costs of $216k and $16k for the SCR and CPOX, respectively. Independent of on-stream factors, SCR catalyst was replaced every 6 years (amortized at 8%), while CPOX catalyst was replaced every year. The CPOX catalyst cost was significantly less due to much higher space velocity. The constant capital cost disadvantage of the fuel flexible case reflected $1.79MM for CPOX-related equipment vs. $0.65 for non-catalyst SCR equipment. Operation at reduced on-stream factor (e.g. peaking) only increased the disadvantage of the fuel flexible case, as the operating cost advantage decreased, while the capital cost disadvantage remained constant.

6.0   CONCLUSIONS

Based on the technical analysis done as part of the conceptual engineering work, the potential exists to develop a 2 ppm gas turbine combustor that is capable of operating on either a blend of natural gas with hydrogen (and other constituents present in the CPOX effluent) or a fuel typical of a coal derived fuel gas. However, significant work will be required to manage fuel composition and combustion aerodynamics.

The results from the process and economic analyses indicated that the fuel flexible combustor did bring value to new NGCC and IGCC plants by eliminating the SCR. The advantage was modest for new IGCC plants, and only marginal for new, baseload NGCC plants in a high power price market. For IGCC, the issue of modest advantages was compounded by the small market for new IGCC plants and the limited business role for Praxair. Even for the potentially larger market of new NGCC plants, the total potential revenue brought to Praxair by the fuel flexible combustor with CPOX offering does not justify the significant investment that will be required to develop the fuel flexible combustor technology and bring it to market.

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