EARLY ENTRANCE COPRODUCTION PLANT

PHASE II

Topical Report

Task 2.4: Low Btu Combustion Test

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ABSTRACT

The overall objective of this project is the three phase development of an Early Entrance Coproduction Plant (EECP) which uses petroleum coke to produce at least one product from at least two of the following three categories: (1) electric power (or heat), (2) fuels, and (3) chemicals using ChevronTexaco's proprietary gasification technology. The objective of Phase I is to determine the feasibility and define the concept for the EECP located at a specific site; develop a Research, Development, and Testing (RD&T) Plan to mitigate technical risks and barriers; and prepare a Preliminary Project Financing Plan. The objective of Phase II is to implement the work as outlined in the Phase I RD&T Plan to enhance the development and commercial acceptance of coproduction technology. The objective of Phase III is to develop an engineering design package and a financing and testing plan for an EECP located at a specific site.

The project's intended result is to provide the necessary technical, economic, and environmental information needed by industry to move the EECP forward to detailed design, construction, and operation. The partners in this project are Texaco Energy Systems LLC or TES (a subsidiary of ChevronTexaco), General Electric (GE), Praxair, and Kellogg Brown & Root (KBR) in addition to the U.S. Department of Energy (DOE). ChevronTexaco is providing gasification technology and Fischer-Tropsch (F-T) technology developed by Rentech, GE is providing combustion turbine technology, Praxair is providing air separation technology and KBR is providing engineering.

For the EECP, a GE PG6101 (6FA) 60 Hertz (Hz) Heavy Duty Gas Turbine (GT) equipped with an integrated gasification and combined cycle (IGCC) combustor will provide electrical power for internal use and export. The GT uses a dual fuel supply system with natural gas as the startup/backup fuel and a mixture of synthesis gas, acid gas recovery (AGR) off gas, and F-T tail gas as the primary fuel. Nitrogen from the air separation unit (ASU) will be used for the fuel purge system and diluent injection for nitrogen oxides (NOx) abatement.

Phase I identified the lower heating value (LHV) of the primary fuel gas as a technical risk for mitigation. The LHV of the primary fuel gas is lower than the value at which current commercial GT combustion systems are available. The life of the component parts and the emissions from the combustion system are also unknown. Changes in the primary fuel composition represent another technical risk and design deficiency identified by the EECP team. The EECP F-T reactor will not operate full time. When the F-T reactor is not operating, the only feeds to the combustor will be the synthesis gas and AGR off gas. The combustor must be designed to use the synthesis gas/AGR off gas fuel combination. An additional technical risk is that variability in the AGR off gas would also change the LHV of the primary fuel.

In May 2002, GE Power Systems (GEPS) conducted a low-British Thermal Unit (Btu) gas combustion test as part of Task 2.4 of Phase II of the EECP program. The test, originally to be conducted in the Combustion Development Laboratory in Schenectady, NY in 2001, was eventually conducted in the new facility of the Gas Turbine Technology Laboratory (GTTL) in Greenville, SC. The test was run on a GEPS combustion laboratory test stand mounted with a single combustor of a GE PG6101 (6FA) 60 Hertz (Hz) heavy duty gas turbine. The primary objective was to verify the full range operation of the combustor on the low Btu fuel mixtures

from the proposed EECP. The low Btu fuel mixture includes synthesis gas from the oxygen-blown gasification section and low Btu tail gas from the F-T unit. Fuel composition effects and diluent injection effects were also studied. The test has successfully demonstrated satisfactory operation of a GE 6FA IGCC combustor using low Btu fuels with diluent injection for control of NOx emissions tat are typical for the EECP concept. This report describes the test facility and operating conditions, discusses the results in terms of emissions, liner metal temperature, combustor pressure drop, combustor exit temperature profile, and combustion dynamics, and presents the resulting conclusions and recommendations for further evaluation.

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The Contractor cannot confirm the authenticity of the information contained herein since this report is being submitted under the U.S. Department of Energy requirement that the electronic files must be submitted without being write-protected

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II. Executive Summary

The overall objective of this project is the three phase development of an EECP which uses petroleum coke to produce at least one product from at least two of the following three categories: (1) electric power (or heat), (2) fuels, and (3) chemicals using ChevronTexaco's proprietary gasification technology. The objective of Phase I was to determine the feasibility and define the concept for the EECP located at a specific site; develop a Research, Development, and Testing (RD&T) Plan to mitigate technical risks and barriers; and prepare a Preliminary Project Financing Plan. The objective of Phase II is to implement the work as outlined in the Phase I RD&T Plan to enhance the development and commercial acceptance of coproduction technology. The objective of Phase III is to develop an engineering design package and a financing and testing plan for an EECP located at a specific site.

For the EECP, a GE PG6101 (6FA) 60 Hertz (Hz) Heavy Duty Gas Turbine (GT) equipped with an integrated gasification and combined cycle (IGCC) combustor will provide electrical power for internal use and export. The GT uses a dual fuel supply system with natural gas as the startup/backup fuel and a mixture of synthesis gas, acid gas recovery (AGR) off gas, and F-T tail gas as the primary fuel. Nitrogen from the air separation unit (ASU) will be used for the fuel purge system and diluent injection for nitrogen oxides (NOx) abatement.

Phase I identified the lower heating value (LHV) of the primary fuel gas as a technical risk for mitigation. The LHV of the primary fuel gas is lower than the value at which current commercial GT combustion systems are available. The life of the component parts and the emissions from the combustion system are also unknown. Changes in the primary fuel composition represent another technical risk and design deficiency identified by the EECP team. The EECP F-T reactor will not operate full time. When the F-T reactor is not operating, the only feeds to the combustor will be the synthesis gas and AGR off gas. The combustor must be designed to use the synthesis gas/AGR off gas fuel combination. An additional technical risk is that variability in the AGR off gas would also change the LHV of the primary fuel.

Phase II, Task 2.4 of the EECP project required GE Power Systems (GEPS) to conduct a low Btu gas combustion test. GEPS performed this test on May 7-8, 2002 in the new Gas Turbine Technology Laboratory (GTTL) in Greenville, South Carolina. The major objective of the test was to validate that the full range operation of current combustor design of a GE PG6101 (6FA) 60 Hz heavy duty gas turbine using a simulation of the low Btu-mixture of the proposed EECP. The low Btu-mixture includes F-T tailgas, AGR offgas, and gasifier synthesis gas resulting from the EECP coal/coke gasification. This test at GTTL has confirmed satisfactory operation of the GE 6FA IGCC combustor using low Btu fuels with diluent injection for control of NOx emissions that are typical for the EECP concept.

The test was conducted with a single GE 6FA IGCC type combustor mounted on a test stand designed to simulate the inlet and outlet interface with the combustor. ChevronTexaco identified twelve different EECP cases in a test matrix (see Appendix). Two low Btu fuels, bracketing the twelve cases, were selected to investigate the effect of fuel composition. From these two cases, GEPS and ChevronTexaco defined a set of test points. The test points included two additional synthesis gas fuel test points and four natural gas test points for the backup fuel. Nitrogen (N_2)

was injected through the head end of the combustor to study its effect on nitrogen oxides (NOx) abatement.

During the test, a number of facility issues on flow and control of the low Btu fuel composition system prevented the setting of test point conditions according to plan. Redundant measurements and systematic analyses of the data however provided enough valuable information to address the test objectives. The general conclusions drawn from the test program are:

1. Low Btu EECP fuels typical of the EECP concept are viable for GE gas turbine applications
2. It was found that all the test points attempted showed no sign of combustion related problems that may produce excessive emissions or adversely impact the normal life of component parts.
3. Low NOx and low carbon monoxide (CO) emissions are possible with N_2 injection for 6FA application.
4. Less than 10 parts-per-million (ppm) of NOx and CO emissions at 6FA full-load conditions appear feasible with an appropriate amount of nitrogen injection.

III. Test Report

1. Introduction

As shown is Schematic 1, petroleum coke is ground, mixed with water (H_2O) and pumped as thick slurry to the Gasification Unit. This coke slurry is mixed with high-pressure oxygen from the Air Separation Unit (ASU) and a small quantity of high-pressure steam in a specially designed feed injector mounted on the gasifier. The resulting reactions take place very rapidly to produce synthesis gas, also known as syngas, which is composed primarily of hydrogen, carbon monoxide, water vapor, and carbon dioxide (CO_2) with small amounts of hydrogen sulfide (H_2S), methane, argon, N_2, and carbonyl sulfide. The raw syngas is scrubbed with water to remove solids, cooled, and then forwarded to the Acid Gas Removal Unit (AGR), where the stream is split. Approximately 75% of the synthesis gas is treated in the AGR to remove the bulk of H_2S with minimal CO_2 removal and then forwarded as fuel to the 6FA gas turbine. The remaining 25% of the stream is treated in the AGR to remove CO_2 and H_2S and then passed through a zinc oxide guard bed to remove the remaining traces of sulfur before being forwarded to the F-T Synthesis Unit. In the AGR solvent regeneration step, high pressure nitrogen from the ASU is used as a stripping agent to release CO_2. The resulting CO_2 and N_2 mixture (AGR offgas) is also sent to the gas turbine, which results in increased power production and reduced nitrogen oxides emissions. The bulk of the nitrogen from the air separation unit is sent to the gas turbine as a separate stream and combined in the combustion chamber with the synthesis gas fuel to increase the power production and reduce nitrogen oxide emissions from the gas turbine.

In the F-T reactor, carbon monoxide and hydrogen react, aided by an iron-based catalyst, to form mainly heavy, straight-chain hydrocarbons. Since the reactions are highly exothermic, cooling coils are placed inside the reactor to remove the heat released by the reactions. Three hydrocarbon product streams, heavy F-T liquid, medium F-T liquid and light F-T liquid are sent to the F-T product upgrading unit while F-T water, a reaction byproduct, is returned to the Gasification Unit. The F-T tail gas and AGR off gas are fed to the gas turbine and mixed with syngas. This increases electrical power production by 11%.

In the F-T Product Upgrading Unit (F-TPU), the three F-T liquids are combined and processed as a single feed. In the presence of a hydrotreating catalyst, hydrogen reacts slightly exothermally with the feed to produce saturated hydrocarbons, water, and some hydrocracked light ends. The resulting four liquid product streams, naphtha, diesel, low-melt wax, and high-melt wax, leave the EECP facility via tank truck.

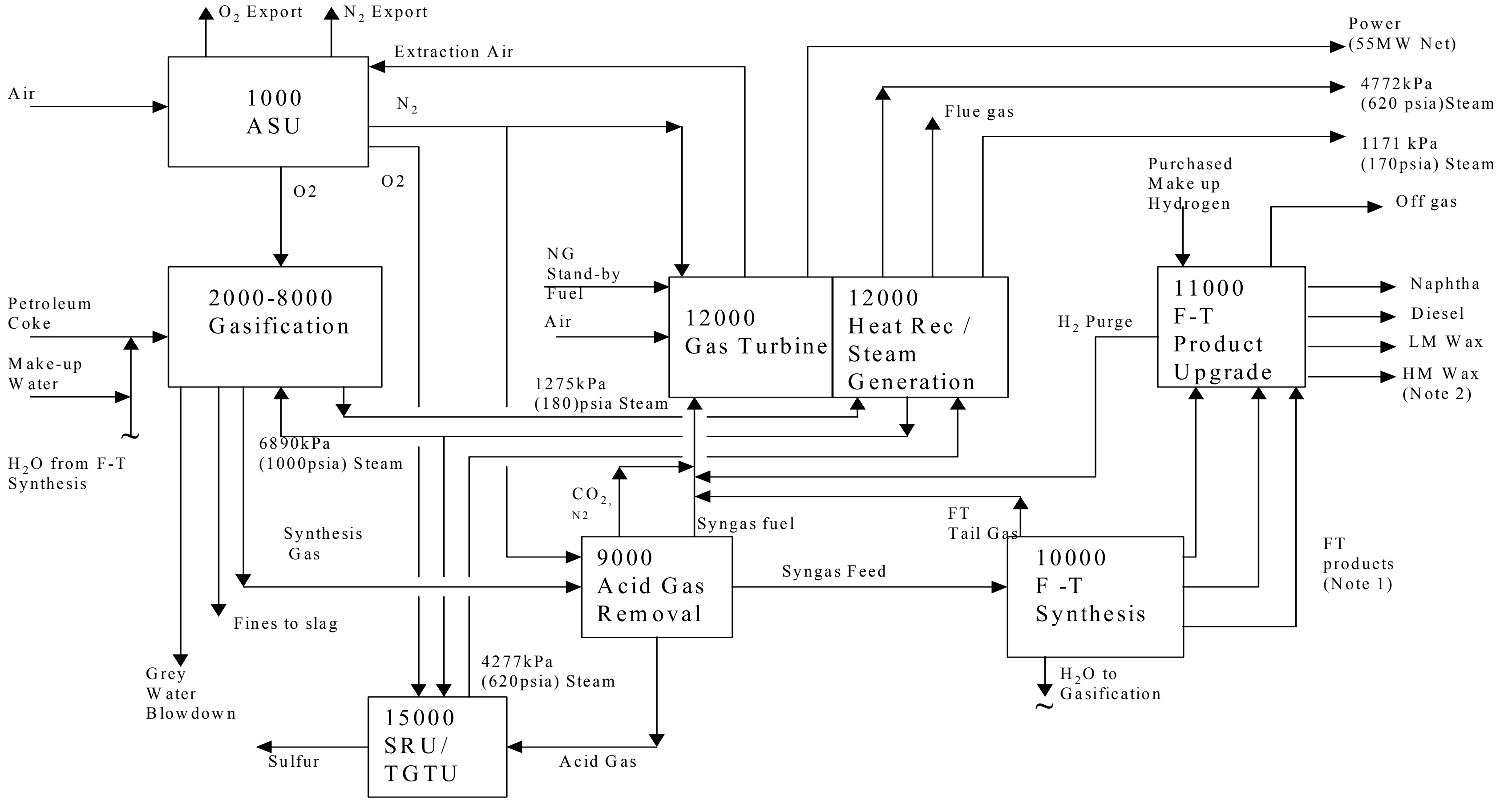
The power block consists of a GE PG6101 (6FA) 60 Hertz (Hz) heavy-duty gas turbine generator and is integrated with a two-pressure level heat recovery steam generator (HRSG) and a non-condensing steam turbine generator. The system is designed to supply a portion of the compressed air feed to the ASU, process steam to the refinery, and electrical power for export and use within the EECP facility. The gas turbine has a dual fuel supply system with natural gas as start-up and backup fuel, and a mixture of synthesis gas from the gasifier, offgas from the AGR Unit, and tail gas from the F-T Synthesis Unit as the primary fuel. Nitrogen gas for injection is supplied by the ASU for NOx abatement, power augmentation, and the fuel purge system.

The Praxair ASU is designed as a single train elevated pressure unit. Its primary duty is to provide oxygen to the gasifier and Sulfur Recovery Unit (SRU), and to satisfy all of the EECP's requirements for N_2, instrument air, and compressed air. Nitrogen produced by the ASU is used within the EECP as a stripping agent in the AGR Unit, as diluents in the gas turbine where its mass flow helps increase power production and reduce NOx emissions, and as an inert gas for purging. The gas turbine, in return for diluent nitrogen, supplies approximately 25% of the air feed to the ASU, which helps reduce the size of the ASU's air compressor and oxygen supply cost.

Acid gases from the AGR, as well as sour water stripper (SWS) off gas from the Gasification Unit, are first routed to knockout drums and then to the Claus Sulfur Recovery Unit (SRU). After entrained liquid is removed in these drums, the acid gas is preheated and fed along with the SWS off gas, oxygen, and air to a burner. In the thermal reactor, the H_2S, a portion of which has been combusted to sulfur dioxide (SO_2), starts to recombine with the SO_2 to form elemental sulfur. The reaction mixture then passes through a boiler to remove heat while generating steam. The sulfur-laden gas is sent to the first pass of the primary sulfur condenser where all sulfur is condensed. The gas is next preheated before entering the first catalytic bed in which more H2S and SO_2 are converted to sulfur. The sulfur is removed in the second pass of the primary sulfur condenser, and the gas goes through a reheat, catalytic reaction, and condensing stage two more times before leaving the SRU as a tail gas. The molten sulfur from all four condensing stages is sent to the sulfur pit, from which sulfur product is transported off site by tank truck.

The tail gas from the SRU is preheated and reacted with hydrogen in a catalytic reactor to convert unreacted SO_2 back to H_2S. The reactor effluent is cooled while generating steam before entering a quench tower for further cooling. A slip stream of the quench tower bottoms is filtered and sent along with the condensate from the SRU knockout drums to the SWS. H_2S is removed from the quenched tail gas in an absorber by using lean methyldiethanolamine (MDEA) solvent from the AGR Unit. The tail gas from the absorber is thermally oxidized and vented to the atmosphere. The rich MDEA solvent returns to the AGR Unit to be regenerated in the stripper.

Phase I identified the lower heating value (LHV) of the primary fuel gas as a technical risk for mitigation. The EECP primary fuel gas' LHV is lower than the value at which current commercial GT combustion systems are available. The life of the component parts and emissions for the combustion system are also unknown. Short life of the component parts or failure to meet emissions standards would cause the commercial coproduction plant design to be altered. Changes in the primary fuel composition represent another technical risk and design deficiency identified by the EECP team. The EECP F-T reactor will not operate full time. When the F-T reactor is not operating, the only feeds to the combustor will be the synthesis gas and AGR off gas. The combustor must be designed to use the synthesis gas/AGR off gas fuel combination. An additional technical risk is that variability in the composition of the AGR offgas would also change the LHV of the primary fuel.



Kellogg Brown & Root, Inc.
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Engineering services by Halliburton
Technical Services, Inc.

NOTES:

1. Includes Light, Medium and Heavy FT Liquid product streams
2. LM = Low Melt
   HM = High Melt

DOE EARLY ENTRANCE COPRODUCTION PLANT
PORT ARTHUR REFINERY

OVERALL BLOCK FLOW DIAGRAM

DRAWN JSA	DATE 10/10/0	DOE AWARD NUMBER: DE-FC-99FT40658	REV.
DESIGNER	DATE	SUBCONTRACTOR PROJECT NO: 9202	0
CHECKED	DATE	TASK NO: 4.1.2	
APPROVED	DATE	DRAWING NO: KBR-P-BFD-0001	

Schematic 1 - EECP Concept

1.1. Objectives

TES and the EECP team have studied a total of 12 cases of gas turbine feed (see Appendix 1) based on different operating scenarios of EECP demo plant. However, only two cases based on the lowest Btu case and highest Btu case were selected for testing. The lower heating value (LHV) of the primary fuel, however, is lower than the value that has been demonstrated in the current 6FA IGCC combustor design. Another potential technical risk is the fuel composition variation. When the EECP F-T reactor is not operating, the primary fuel consists only of syngas and AGR offgas. A combustion test is therefore required to verify that the current combustor design can handle the fuel and its variation. Since nitrogen from the ASU will be used as diluent for NOx abatement, its effect should also be evaluated. In summary, the test was planned with focus on the following three objectives:

1) To verify GE combustor design for EECP fuel
2) To evaluate the effect of fuel composition
3) To determine the effectiveness of nitrogen diluent injection for NOx abatement

1.2. Approach

The 6FA GT has six combustors. For lab testing purposes, only a single combustor is tested. The combustor is mounted on a test stand designed for simulating the inlet (compressor discharge) and outlet (turbine inlet) conditions for the combustor. The testing was originally planned for the third quarter of 2001 in the Combustion Development Laboratory of GEPS in Schenectady, NY. Before the test was run, GEPS decided to move the lab to a new facility, Gas Turbine Technology Laboratory (GTTL) in Greenville, SC. The test was run in GTTL in early May 2002.

2. Test Facilities

GTTL is a state-of-the-art gas turbine combustion testing facility. It is built with a fuel farm for low Btu gases, currently capable of blending up to six individual gases including hydrogen, carbon monoxide, natural gas, nitrogen, steam, and carbon dioxide. The lab has five test cells. Each can accommodate two test stands.

2.1. Fuel Blending System

Most of the blended fuel gases are stored as liquid in tanks. The two exceptions are: natural gas, which is continuously supplied by a local gas company and CO, a specialty gas that can only be supplied in high-pressure gas tubes mounted on trailers. CO is the limiting fuel. It is consumed well before other gases run out. It also takes time for the CO trailers to be replenished. The empty trailers have to be removed before new ones can be moved into the 13 parking spaces dedicated for CO trailers. Hydrogen, nitrogen, and carbon dioxide are supplied from a liquid-to-gas system with a heating / vaporizing system. Steam is generated from a boiler with superheating capability. Each of these gas streams flow through its own flow measurement section, consisting of both a coarse and fine section for different flow rates. The fuel streams then come together at the blended fuel header before going through or bypassing the fuel heater. The bypass allows fast temperature control of the fuel before it enters the test cell.

The three non-combustibles, namely, nitrogen, steam, and carbon dioxide, can also be branched-off to be used in diluent injection or power augmentation. The diluent flows through its own heater for temperature control. All of the fuel streams and diluent can be independently controlled through their own flow control valve.

2.2. Test Stand and Test Hardware

A schematic of the test stand is shown in Figure 1. It provides an interface with a single combustor and simulates the upstream and downstream conditions of the combustor. The combustion air, typically supplied by two compressors, passes through flow sections at which the flow rate is controlled and measured (not shown in the figure). Through a diffuser, the air enters the main chamber, which is essentially a pressurized enclosure to simulate compressor discharge casing (see Figure 2).

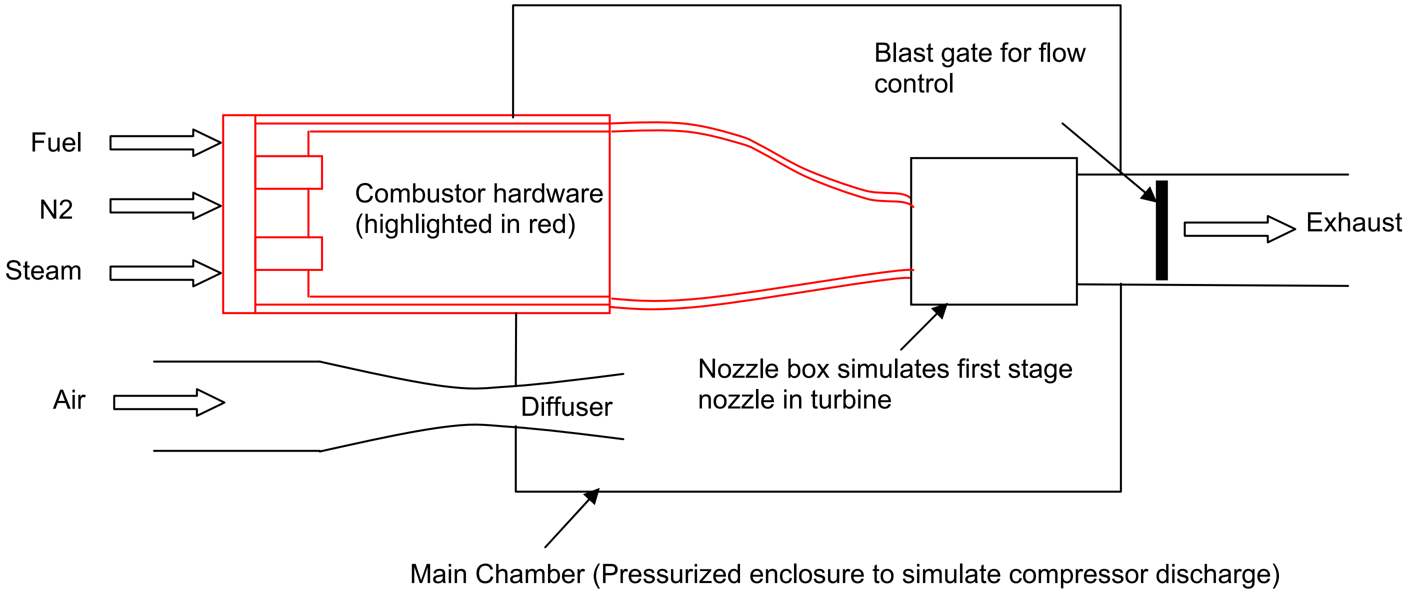
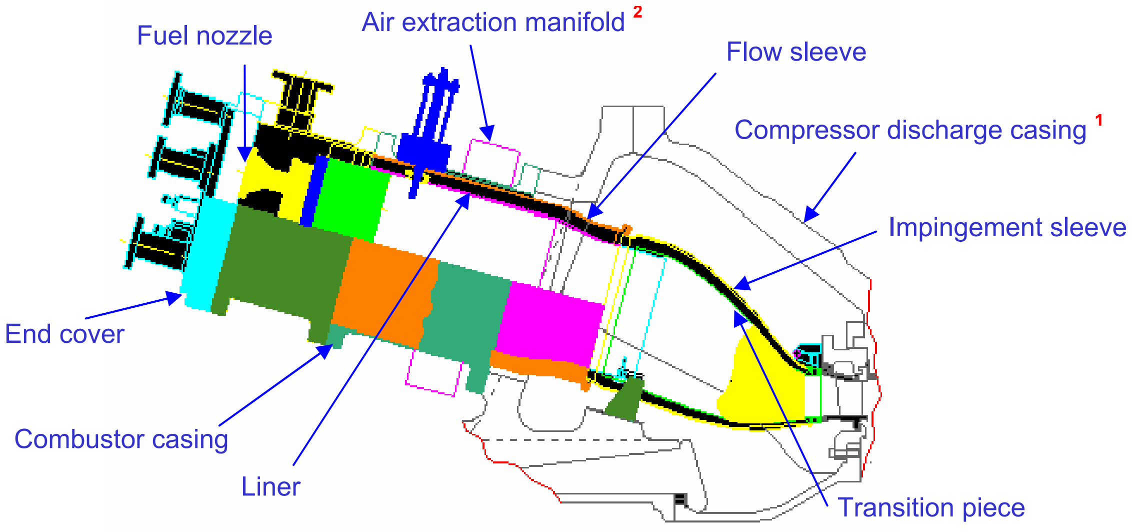


Figure 1. Combustion Laboratory Test Stand Schematic



[1] Test stand simulates the compressor discharge casing with a pressurized enclosure.
[2] Test stand has no provision for air extraction piping. To simulate effect of air extraction, amount of air flow into the combustor is reduced.

Figure 2. Combustor schematic

The air then flows through the impingement sleeve of the transition piece assembly and the flow sleeve hole and enters the annulus space (area in black in Figure 2) between the flow sleeve and liner. It then travels towards the head end of the combustor.

In actual GT operation with air extraction from the combustor casing, part of the air will flow through a row of holes on the circumference of the flow sleeve and subsequently through a corresponding row of holes on the casing into a manifold that wraps around the casing. The air is then extracted out from a single flange at the top dead center (TDC) of the combustor. However, for this test, the impact of air extraction is simulated by reducing the amount of combustion air by the amount of air that is supposed to be extracted. The air continues towards the head end and finally turns 90 degrees towards the fuel nozzles.

There are six sets of fuel nozzles mounted on the end cover. Each set of fuel nozzles consists of an inner nozzle tip in the center normally reserved for startup or backup fuel (also referred to as secondary fuel). For this test, natural gas was the secondary fuel. The fuel nozzle set also has an outer nozzle tip for low Btu gas (also referred to as primary fuel). All fuel nozzle tips are connected to circular passages fabricated inside the end cover for primary and secondary fuels. Figure 3 is a piping diagram for fuel and purge air. The fuels are introduced through separate pipes on the end cover.

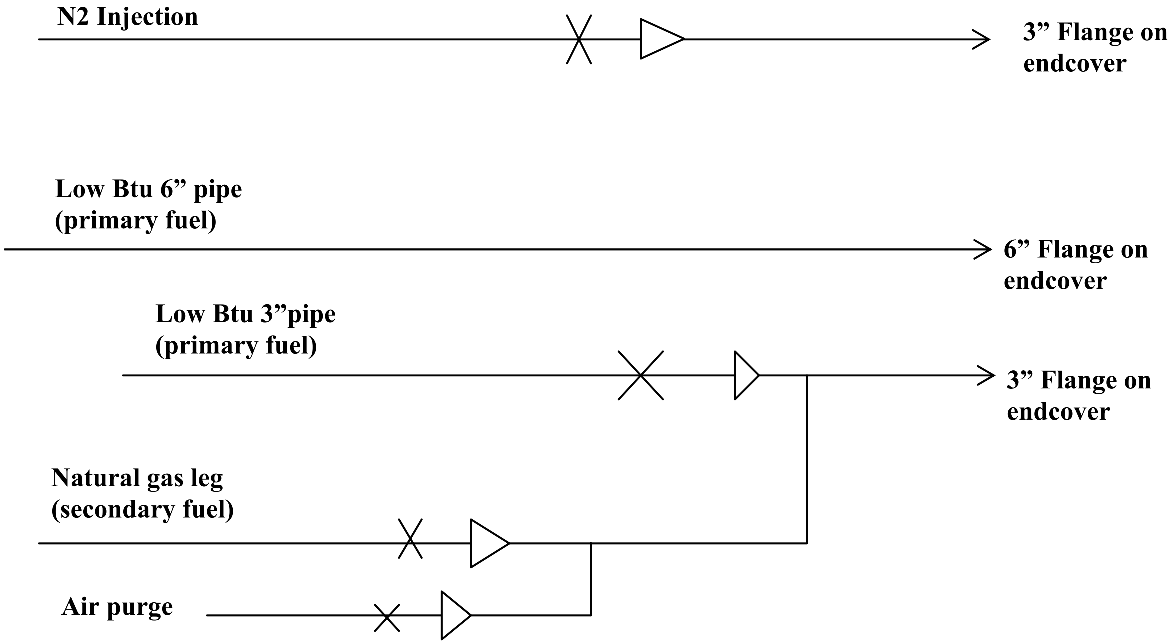


Figure 3. **Fuel and Purge Piping Diagram**

In this test, when operated on low Btu fuel, both the primary and secondary fuel nozzle tips were utilized. This was achieved by installing a 3” piping split-off from the 6” low Btu gas pipe and connected to the natural gas leg. Before the transfer, this 3” pipe section was shut off with an isolation valve. The valve was opened when ready to flow low Btu gas through both fuel nozzle tips. This mode of operation was necessary because the primary fuel nozzle tips alone did not have sufficient effective area to flow the high flow rate of low Btu fuel. The additional effective area provided by the secondary tips helped keeping the pressure ratio across the fuel nozzle tips below an acceptable limit, beyond which the flame structure may no longer be desirable.

Diluent injection is introduced through a pipe on the end cover. It travels through a circular internal passage with a row of holes on the downstream side of the wall, opening into a plenum enclosed by a baffle plate. The baffle plate has six openings for the six fuel nozzle sets. The diluent then passes through the circular gap between the baffle plate and each fuel nozzle body. From that point onward, the diluent mixes with the air at the headend. Part of this diluent/air mixture ends up flowing inside the fuel nozzle and the rest passes through a cap at the top of the liner and mixed with the flame downstream inside the liner.

There are combustion air holes near the upstream end of the liner, which provide a penetrating air jet to mix with the fuel-air-diluent mixture in the flame zone. Along the length of the liner, there are rows of small film cooling holes for liner cooling. Towards the downstream end of the liner, there is a row of dilution holes where air flows inside the liner to dilute the burned gas. Downstream of the dilution holes, the diameter of the liner was slightly reduced through a cone section. The smaller diameter aft end of the liner is fitted with a hula seal, which engages the transition piece and seals off the hot gas path.

Referring to Figure 1, the transition piece is connected to a nozzle box constructed to simulate the first stage nozzle (S1N) of the turbine. The nozzle box simply consists of a set of bars with space in between. The hot burned gas flows through the open areas between the bars. The total effective area of the nozzle box matches that of the S1N. Immediately upstream of the nozzle box are a total pressure probe to monitor the combustor exit pressure and a thermocouple rake where a matrix of thermocouples are spatially distributed to map the temperature field at the combustor exit. Downstream of the nozzle box is a blast gate, the percent opening of which can be adjusted to maintain a certain pressure between the nozzle box and the blast gate. This pressure needs to be maintained in order to drive the exhaust gas sample through the sampling line to the gas analyzers.

2.3. Instrumentation

Temperature and pressure probes are installed on the combustor to monitor the performance of the combustor. Table 1 is a summary of the instrumentation and the corresponding parameters monitored. The mass flow rate of each individual flow stream is not included in this table. The air flow and the natural gas streams were measured by American Society of Mechanical Engineers (ASME) flow nozzles. Other flow streams were measured with flow orifices.

Table 1. Summary of Instrumentation

Type	Quantity	Parameters Monitored
thermocouple	40	Combustor exit temperature
thermocouple	46	liner metal temperature
thermocouple	1	air inlet temperature
thermocouple	1	primary fuel temperature
thermocouple	1	Secondary fuel temperature
thermocouple	1	diluent temperature[1]
pressure probe	1	main chamber pressure
pressure probe	1	Combustor pressure drop
pressure probe	1	primary fuel pressure
pressure probe	1	Secondary fuel pressure
Kiel probe	8	static pressure total pressure velocity
PCB probe	1	Combustor dynamics
PCB probe	1	Manifold dynamics
PCB probe	1	Manifold dynamics
PCB probe	1	Manifold dynamics
Barometer	1	ambient pressure
psychrometer	1	specific humidity
gas sampling probe	1	Exhaust emissions[2]
gas sampling probe	1	Blended fuel composition[3]

Note:

1) diluent include nitrogen for low Btu gas and steam for natural gas

2) include NOx, NO, CO, O2, CO2, total UHC

3) measured by mass spectrometer

Calibration of the pressure transducers and thermocouples were routinely performed before each test. Calibration of gas analyzer and mass spectrometer were calibrated and zero checked before and after the test.

Typically, the flow measurement error is about 1.0%.

The capabilities of the gas analyzer and mass spectrometer are listed in Table 2 and Table 3, respectively.

Table 2: **Gas analyzers capability (ppm values are by volume)**

Analyzer	Process	Calibration Ranges	Minimum Range	Maximum Range	**Limit of detection**	Calibration Span Gas
Rosemount NGA 2000/CLD	**NO/NOx**	**0–25 ppm** **0–100 ppm** **0-250 ppm** **0-500 ppm**	**0-10 ppm**	**0-1000 ppm**	0.1 ppm	**20 ppm** **80 ppm** **200 ppm** **200 ppm**
Rosemount NGA 2000/NDIR	**CO$_2$**	**0-5 %** **0-10 %** **0-20 %**	**0-2 %**	**0-20 %**	0.1 %	**3.5 %** **5 %** **5 %**
Rosemount NGA 2000/PMD	**O2**	**0-25 %**	**0-1 %**	**0-100 %**	0.01 %	**12.5 %**
Rosemount NGA 2000/NDIR	**CO (High)**	**0-200 ppm** **0-500 ppm** **0-1000 ppm** **0-2000 ppm**	**200 ppm**	**2000 ppm**	0.1 ppm	**175 ppm** **460 ppm** **460 ppm** **460 ppm**
Horiba AMPA 360E/NDIR	**CO (Low)**	**0-10 ppm** **0-20 ppm** **0-100 ppm**	**0-10 ppm**	**0-100 ppm**	0.05 ppm	**7.5 ppm** **7.5 ppm**
Rosemount NGA 2000/FID	**Unburned Hydrocarbons**	**0-100 ppm** **0-500 ppm** **0-1000 ppm** **0-5000 ppm**	**0-10 ppm**	**35 %**	0.04 ppm H$_2$/He fuel	**80 ppm** **200 ppm** **800 ppm** **800 ppm**

For the gas analyzers, the repeatability, zero drift, span drift, linearity are within ±1% full scale. The accuracy of calibration gas is ±1%. For the mass spectrometer, the repeatability is ±0.007% of reading, the hourly drift is ±0.02% full scale, the daily drift is ±0.05% full scale, the monthly drift is ±1.1% full scale. The linearity is less than 0.5% full scale. The accuracy of calibration gas is ±1%.

Table 3. **Mass spectrometer capability**

Analyzer	Process	Minimum Detection Limit	Maximum Detection Limit	Calibration Span Gas
Orbital MGA Mass Spectrometer	**H2**	**0.03 %**	**100 %**	**55 %**
Orbital MGA Mass Spectrometer	**CO$_2$**	**0.03 %**	**20 %**	**15 %**
Orbital MGA Mass Spectrometer	**O2**	0.03 %	**25 %**	**20.9 %**
Orbital MGA Mass Spectrometer	**CO**	0.03 %	100 %	**45 %**
Orbital MGA Mass Spectrometer	**N2**	0.03 %	100 %	**78.1 %**
Orbital MGA Mass Spectrometer	**CH4**	0.03 %	100 %	**45 %**
Orbital MGA Mass Spectrometer	**C2H6**	0.03 %	10 %	**2.5%**
Orbital MGA Mass Spectrometer	C3H8	0.03 %	2 %	0.75 %

3. Test Description

The test was conducted on two separate days, May 7, 2002 and May 8, 2002. The first day of the test was on low Btu gas using nitrogen for diluent injection. The second day of the test was on natural gas using steam for diluent injection. The test procedure and the test conditions will be discussed next.

3.1. Test Procedure

The basic procedures for low Btu gas testing involved the following steps:

- Start-up
- Transfer to low Btu gas
- Establishing test point conditions
- Recording test point
- Blowout

Start-up—Low Btu gas testing always starts up with fuel such as natural gas or distillate oil. In this test, the start-up fuel was natural gas. After the combustor was ignited on natural gas by an electric spark at a reduced air flow and fuel flow conditions, the air flow and temperature was established with the fuel-air ratio increased to maintain a combustor design exit temperature. At this temperature, the transfer to low Btu gas began. This provided a margin for any fuel composition variation during transfer, i.e., the combustor exit temperature could be varied comfortably between full-speed-no-load and full-load operating conditions without risking flame-out or over-firing. During this natural gas operation period, the primary fuel nozzle was purged with air.

Transfer to low Btu gas—The lab is currently capable of blending 6 fuel streams to simulate low Btu gas. Three of them are combustibles, hydrogen (H_2), carbon monoxide (CO), and natural gas (NG). The other three are inert, nitrogen (N_2), carbon dioxide (CO_2), and steam (H_2O). The transfer sequence began with closing down the air purge to the primary fuel nozzle. The blended fuel streams were introduced one stream at a time. One of the inert streams, N_2 for this test, was the first to flow. It served the purpose of purging out the air inside the blended fuel pipeline and prevented the combustibles, particularly H_2 in the blended fuel from mixing with air. This is an important safety step. The flow rate of each stream was manually adjusted to a target flow estimated by cycle calculation. As mentioned earlier, the fuel with relatively limited supply is CO, and to conserve its usage, it was the last stream to be introduced.

When the blended fuel stream was introduced, the natural gas flow through the secondary fuel nozzle was adjusted up and down to maintain the combustor exit temperature. At a convenient point during the transfer process when the upstream pressure of the primary fuel nozzle was slightly higher than that of the secondary fuel nozzle, the isolation valve on the 3" low Btu gas pipe (refer to Figure 3) was opened to allow low Btu fuel flow through the secondary fuel nozzle. Eventually, the natural gas flow was cut off completely when the low Btu gas alone could maintain the combustor exit temperature for a stable flame.

It is obvious that for the test with only natural gas test points, there was no transfer to low Btu gas. After ignition, the air and fuel conditions were adjusted to the desired combustor exit temperature for a test point.

Establishing test point conditions—Under normal operation, after all the blended fuel streams are introduced and manually set close to the target flow, the desired fuel composition based either on mass percentage or volume percentage are entered as set points to the blended fuel flow control system. The fuel control system is then set to operate in automatic mode to maintain the fuel composition. From this point, the total fuel flow of the blended gas can be adjusted up or down to set the combustor exit temperature while keeping the fuel composition constant. During the test, however, the attempt to operate the fuel control in automatic mode failed because the control valves were not well tuned.

Without automatic flow control, each of the blended fuel flows were manually set to a target value as estimated in the test point plan. This procedure set the fuel composition but the total fuel flow still needed to be adjusted in order to reach the desired combustor exit temperature. Considering the limited supply of CO, it would take too much time to manually adjust each of the components in the blended fuel one at a time to set a combustor exit temperature. Consequently, the total fuel flow rate was not adjusted and the combustor exit temperature for the planned test point was not fully simulated. In fact, for most of the test points, the measured combustor exit temperature was lower than that of the planned test point. For test points with diluent injection, nitrogen was introduced manually and set to a target flow determined earlier by cycle calculations.

Recording test point—When the test conditions for a test point were established, test point recording was initiated. The emissions engineer observed the output from the gas analyzer, focusing primarily on the NOx. Once the NOx was stable within ±10%, the test point was recorded on the data acquisition system. The data acquisition system scan all the instrumentation every 2 seconds. All of the scans were recorded into a database. However, 7 scans were tagged for each test point. The dynamics data were also recorded simultaneously. Once the dynamics data were collected, the test point recording was completed. The test was then moved on to the next test point.

Blowout—At the end of the test, the fuel was gradually reduced while keeping the air flow conditions of the last test point constant. This eventually extinguished the flame.

3.2. Test Point Conditions

The EECP team selected a total of 12 test points. The first 4 test points were natural gas points with steam injection for NOx abatement. The rest of the test points were low Btu gas points with or without nitrogen injection, including a blowout point. Two additional test points, which were dependent on the availability of gas, were also included at the end of the test.

3.2.1. Fuel Composition Planned

Two low Btu gas compositions were selected by the EECP team and designated as Case 5b and Case 2. Case 5b is the gasifier design case with high conversion in the F-T synthesis section. Case 2 is the normal operating conditions with the F-T synthesis section not operating. These fuel compositions are shown in Table 4 under the columns labeled "original". Both gases have trace amount of C2+ hydrocarbons, argon, H_2O, and H_2S. Most of these trace components are not part of the six blended fuel components the lab can handle. It was decided that the fuel compositions should be approximated without these trace components. Each of the two fuel compositions was adjusted so that the LHV by volume was almost identical to that of the original. The approximated fuel compositions are listed under column "approximate". The differences between Case 5b and Case 2 gas are highlighted below:

- Case 5b has a slightly lower LHV by volume than Case 2
- Case 5b has a lower CO volume % than Case 2
- Case 5b has a higher CO_2 volume % than Case 2
- Case 5b has a slightly lower N_2 volume % than Case 2

These two cases were selected to evaluate whether such variation in fuel composition would have any effect on combustion.

Table 4. **Fuel compositions planned**

Case 5b	vol%	
	original	approximate
H2O	0.19%	0.00%
H2	23.72%	24.00%
CO	28.68%	28.00%
CO2	22.42%	22.00%
AR	0.22%	0.00%
N2	24.35%	25.00%
C1	0.19%	1.00%
C2	0.09%	0.00%
C3	0.06%	0.00%
C4	0.04%	0.00%
C5	0.02%	0.00%
C6	0.01%	0.00%
H2S	0.01%	0.00%
LHV (BTU/SCF)	164.44	165.10
LHV ratio (tested/designed)		1.004

Case 2	vol%	
	original	approximate
H2O	0.18%	0.00%
H2	24.42%	24.00%
CO	32.23%	32.00%
CO2	16.85%	17.00%
AR	0.00%	0.00%
N2	26.27%	27.00%
C1	0.04%	0.00%
C2	0.00%	0.00%
C3	0.00%	0.00%
C4	0.00%	0.00%
C5	0.00%	0.00%
C6	0.00%	0.00%
H2S	0.01%	0.00%
LHV (BTU/SCF)	170.59	168.80
LHV ratio (tested/designed)		0.989

3.2.2. Test Points Planned

The test points planned are summarized in Table 5. Originally, only 8 syngas fuel test points were planned. Per EECP team suggestion, 2 additional syngas fuel test points and 4 additional natural gas test points for backup fuel operation were added to the list. Cycle deck calculations were performed to estimate all cycle conditions for each test point, including the total low Btu fuel flow rate. The individual blended fuel stream flows were determined based on the total fuel flow rate and the respective fuel mass fraction.

A brief description of the test point conditions is presented below:

- Test point 1 though 4 are natural gas points at 30, 50, 75, 100% load with steam injection to a NOx target of 25 ppm. These natural gas test points provide confirmation of proper IGCC combustor operation on backup fuel. These test points were run with steam injection for NOx abatement as required to meet US Environmental Protection Agency (EPA) air emission permitting requirements.
- Test point 5, 6, and 7 are at 100% load with Case 5b gas and N_2 injection at 0, 50, 100% of the N_2/fuel ratio. This N_2/fuel ratio was defined by the relative amount of Case 5b gas feed and the ASU N_2 diluent feed to the gas turbine.
- Test point 8 and 9 are at 100% load with Case 2 gas and N_2 injection at 100, 110% of the N_2/fuel ratio. This N2/fuel ratio was defined by the relative amount of Case 2 gas feed and the ASU N_2 diluent feed to the gas turbine.
- Test point 10 and 11 are at 50% load and full-speed-no-load (FSNL) respectively, with Case 5b gas but no N_2 injection.
- Test point 12 is an additional point added at 50% load with Case 5b gas and N_2 injection at 100% of the N_2/fuel ratio.
- Test point 13 is an additional point added at 100% load and a higher combustor exit temperature, with Case 5b gas and N_2 injection at 100% of the N_2/fuel ratio.
- Test point 14 is a blowout point for Case 5b gas with no N_2 injection.

Table 5. Test point conditions planned

Test Point ID	Fuel Type	Load Condition	Fuel Temperature (F)	Diluent Type	Diluent Temperature (F)	Nitrogen/Fuel Ratio	Steam/Fuel Ratio
1	NG	30%	80	Steam	550	N/A	1.50
2	NG	50%	80	Steam	550	N/A	1.89
3	NG	75%	80	Steam	550	N/A	2.08
4	NG	100%	80	Steam	550	N/A	2.28
5	Case 5b	100%	400	None	N/A	0.00	N/A
6	Case 5b	100%	400	Nitrogen	550	0.50	N/A
7	Case 5b	100%	400	Nitrogen	550	0.93	N/A
8	Case 2	100%	400	Nitrogen	550	0.94	N/A
9	Case 2	100%	400	Nitrogen	550	1.03	N/A
10	Case 5b	50%	400	None	N/A	N/A	N/A
11	Case 5b	FSNL	400	None	N/A	N/A	N/A
12	Case 5b	50%	400	Nitrogen	550	0.97	N/A
13	Case 5b	100%	400	Nitrogen	550	0.93	N/A
14	Case 5b	Blowout	400	None	N/A	N/A	N/A

3.2.3. Test Point Measured Versus Test Point Planned

Table 6 and 7 present the comparisons between "measured" and "planned" test point conditions for the low Btu gas test points. Each measured test point was compared to a corresponding planned test point as listed in Table 5. Note that the order of the test points run during the test did not follow exactly the order as listed in Table 5. Also, the identification (ID) assigned to each test point measured during the test was different from the ID of the corresponding test point as planned in Table 5. The ratio between the measured and the planned is also shown for some parameters. Test point tp5a was intended to repeat test point tp5 with better settings for the test point conditions. Test point tp7 was an additional test point that was taken as an intermediate point between 50% and 100% N_2/fuel ratio.

The blowout point, test point 14, was attempted but not recorded during the test. During the process of blowing out the combustor by reducing the fuel flow, the flame went out before test conditions were hold steady enough to record an official test point. However, all the test parameters were continuously scanned every two seconds and were recorded.

Table 7 compares the fuel compositions measured based on mass spectrometer. During this test, a CO flow measurement error was not discovered until the flow measurement section was inspected after the test. A plastic cap was found partially blocking the flow orifice. As a result, the actual CO flow rate was considerably lower than what the measurement indicated. Between test point tp9 and tp13, another flow measurement problem occurred. The boiler of the CO_2 vaporizing system tripped. The trip remained unnoticed until CO_2 temperature dropped below its dew point.

These facility problems caused the actual fuel composition and fuel flow rate to deviate considerably from what was expected (refer to Table 6). Consequently, other parameters including combustor exit temperature, main chamber pressure (simulating compressor discharge pressure), diluent-to-fuel ratio, equivalent fuel flow rate (defined as the sum of blended fuel and diluent flow rate) did not match what were planned. In addition, for the earlier test points, the temperature for fuel and diluent were lower than expected. Substantial amount of heat from the fluids was lost to heat the pipes as the streams first flow through the section between the heater exit and the test stand. Later in the test, fuel and diluent temperatures were closer to their expected values as the heat losses to the pipes were adequately compensated.

The blended fuel flow measurements were found to be inaccurate. The fuel composition was measured independently by mass spectrometer, it was used in conjunction with the measured combustor exit temperature to back calculate the equivalent fuel-to-air ratio. Trace amount of O_2, C_2H_6, C_3H_8, and argon were recorded by the mass spectrometer but were discarded as measurement noise in the calculations. Together with the airflow and diluent flow measurements, the blended fuel flow rates in Table 6 were determined.

Table 6. Comparison of low Btu gas test point conditions between measured and planned

	Test point	Fuel type	Load condition	Equivalent fuel/air ratio [1]	Diluent/LBtu fuel ratio [2]	LBtu fuel temperature, deg F	Diluent (N2) temperature, deg F
measured	tp5	-	-	0.2906	0.00	210.1	-
planned	5	case 5b	100%	-	0.00	400.0	-
ratio					1.00	0.53	
measured	tp5a	-	-	0.2905	0.00	217.9	-
planned	5	case 5b	100%	-	0.00	400.0	-
ratio					1.00	0.54	
measured	tp6	-	-	0.4423	0.54	253.7	223.9
planned	6	case 5b	100%	-	0.50	400.0	550.0
ratio					1.08	0.63	0.41
measured	tp7	-	-	0.4752	0.74	270.1	393.5
planned	-	-	-	-	-	-	-
ratio					-	-	-
measured	tp8	-	-	0.5238	1.19	416.5	465.2
planned	7	case 5b	100%	-	0.93	400.0	550.0
ratio					1.28	1.04	0.85
measured	tp9	-	-	0.5347	1.05	402.1	454.5
planned	9	case 2	100%	-	1.03	400.0	550.0
ratio					1.02	1.01	0.83
measured	tp10	-	-	0.4473	0.74	400.4	489.8
planned	8	case 2	100%	-	0.94	400.0	550.0
ratio					0.79	1.00	0.89
measured	tp11	-	-	0.5354	0.60	400.0	515.0
planned	12	case 5b	50%	-	0.97	400.0	550.0
ratio					0.62	1.00	0.94
measured	tp12	-	-	0.3297	0.00	402.1	-
planned	10	case 5b	50%	-	0.00	400.0	-
ratio					1.00	1.01	
measured	tp13	-	-	0.0528	0.00	383.5	-
planned	11	case 5b	FSNL	-	0.00	400.0	-
ratio					1.00	0.96	

Note 1: Due to blended fuel flow stream measurement error, Equivalent fuel / Air ratio was back calculated based on fuel composition measured by mass spectrometer and combustor exit temperature

Note 2: Calculated based on back calculated Low Btu fuel flow

Table 7. Comparison of low Btu gas fuel compositions between measured and planned

	Test point	Fuel type	Mass Spec H2,%moleDry	Mass Spec C0,%moleDry	Mass Spec N2,%moleDry	Mass Spec CH4,%moleDry	Mass Spec CO2,%moleDry
measured	tp5	-	27.6	19.7	28.1	1.0	23.2
planned	5	case 5b	24.0	28.0	25.0	1.0	22.0
ratio			1.15	0.70	1.13	1.05	1.05
measured	tp5a	-	29.9	20.3	27.4	1.0	21.1
planned	5	case 5b	24.0	28.0	25.0	1.0	22.0
ratio			1.25	0.72	1.10	1.05	0.96
measured	tp6	-	31.9	19.9	27.4	1.1	19.3
planned	6	case 5b	24.0	28.0	25.0	1.0	22.0
ratio			1.33	0.71	1.10	1.07	0.88
measured	tp7	-	28.2	19.0	27.3	1.1	24.1
planned	-	case 5b	24.0	28.0	25.0	1.0	22.0
ratio			1.18	0.68	1.09	1.07	1.10
measured	tp8	-	30.6	19.7	27.5	1.1	20.8
planned	7	case 5b	24.0	28.0	25.0	1.0	22.0
ratio			1.28	0.70	1.10	1.07	0.95
measured	tp9	-	28.6	19.7	28.8	0.0	22.5
planned	9	case 2	24.0	32.0	27.0	0.0	17.0
ratio			1.19	0.62	1.07	1.00	1.33
measured	tp10	-	28.5	21.5	29.1	0.0	20.6
planned	8	case 2	24.0	32.0	27.0	0.0	17.0
ratio			1.19	0.67	1.08	1.00	1.21
measured	tp11	-	26.0	16.6	24.5	0.9	31.7
planned	12	case 5b	24.0	28.0	25.0	1.0	22.0
ratio			1.08	0.59	0.98	0.87	1.44
measured	tp12	-	26.5	18.9	26.2	1.0	27.0
planned	10	case 5b	24.0	28.0	25.0	1.0	22.0
ratio			1.11	0.68	1.05	1.00	1.23
measured	tp13	-	27.3	22.1	25.4	1.1	23.8
planned	11	case 5b	24.0	28.0	25.0	1.0	22.0
ratio			1.14	0.79	1.02	1.13	1.08

The natural gas test points were closely simulated to the planned conditions. Comparisons between the measured and planned test points are tabulated in Table 8. Test point ng2 was an additional test point similar to test point ng3 in terms of load condition, but with a lower diluent (H_2O)-to-fuel ratio. Most of the measured parameters are within a few percent of their respective planned values. However, the measured natural gas fuel flow rate is consistently higher than the expected by 8-12%. .

This discrepancy can be partly explained by the fact that cycle deck assumes natural gas as 100% methane, whose LHV is 4% greater than the natural gas used in this test. The composition of the natural gas is included at the end of Table 8. The other reason is related to the combustor's actual transient piece leakage flow. However, the increased leakage flow in the combustion hardware in the test was higher than was assumed and reduced the measured combustor exit temperature, and thus required higher fuel flow to match the temperature as planned .The increase in natural gas flow rate is small (~ 0.1 lb/s) and should have no significant impact on other operating parameters.

Table 8. Comparison of natural gas test point conditions between measured and planned

	Test point	Load condition	Equivalent fuel/air ratio	Diluent/natural gas ratio	natural gas temperature, deg F	Diluent (H2O) temperature, deg F
measured	ng2	100%	0.0665	1.38	76.8	544.4
planned	-	-	-	-	-	-
ratio				-	-	
measured	ng3	100%	0.0993	2.10	80.8	553.7
planned	4	100%	-	2.28	80.0	550.0
ratio				1.00	1.01	1.01
measured	ng4	75%	0.0921	1.90	80.1	553.4
planned	3	75%	-	2.08	80.0	550.0
ratio				1.00	1.00	1.01
measured	ng5	50%	0.0859	1.78	77.9	550.7
planned	2	50%	-	1.89	80.0	550.0
ratio				1.00	0.97	1.00
measured	ng6	30%	0.0560	1.30	78.0	546.9
planned	1	30%	-	1.50	80.0	550.0
ratio				1.00	0.98	0.99

Natural gas composition, volume percent
(based on routinely updated composition from local natural gas supply company)

CH_4	96.23%
Ethane (C_2H_6)	2.24%
CO_2	1.00%
N_2	0.52%

4. Results and Discussions

The results will be discussed in detail in the following sections, focusing primarily on fuel properties, emissions including NOx, CO, and unburned hydrocarbon (UHC), combustor pressure drop, metal temperature, and dynamics.

4.1. Fuel Properties

The key objective of this test is to evaluate whether the low Btu fuels characteristic of the EECP concept can be burned in the 6FA IGCC gas turbine combustor with various levels of nitrogen injection, for NOx abatement, as specified in the test plan. Unfortunately, as mentioned in section 3.2.3, a series of facility problems prohibited the correct simulation of the test point conditions, particularly the low Btu fuel compositions. Nevertheless, based on this set of off-design data, it is still possible to draw some sort of projection on the fuels originally planned but not tested. Experience from past IGCC combustor development has led to the identification of the key parameters and trends that matter to low Btu gas combustion. The discussion hereafter will be devoted to fuel analysis (including both the measured cases and planned case) in terms of their crucial properties.

Table 9 compares the fuel properties of the measured to the planned test points. A number of parameters were considered:

- LHV of the low Btu gas and the equivalent fuel, which is defined as the sum of the low Btu fuel and the diluent.
- Upper to low flammability limit (U/L FLR) of the low Btu gas and the equivalent fuel
- H_2/CO ratio of the low Btu gas
- Overall equivalence ratio, defined for the equivalent fuel.

A graphical representation of the comparison between measured and planned fuel compositions can be found in Figure 4, in which the ratio of measured to planned mole fraction of each blended fuel component (as shown in Table 7) was plotted for each test point. In general, N_2 and CH_4 behaved fairly well as planned. CO_2 however fluctuated above and below unity, forcing the mole fraction of other constituents to deviate from their planned values. For example, between test point tp10 and tp11, CO_2 took a big step increase and drove down the other components. When CO_2 returned back closer to its planned value between test point tp11 and tp13, the other constituents also moved closer to their planned values.

It is obvious that CO was lower than planned and H_2 remained higher than expected for all test points. This creates a H2/CO ratio of greater than unity instead of less than unity as planned. The behavior of H_2/CO ratio for the test points can also be seen in Figure 5, which plots the ratio of measured to planned values of the key fuel properties as presented in Table 9. For some of the test points, like tp9, the measured H_2/CO ratio (= 1.45) was almost a factor of two of its planned value (=0.75). When comparing the values of H_2/CO ratio, one should keep in mind the ratio can potentially vary over an extremely wide range between zero and infinity, depending on whether H_2 or CO is absent in the blended fuel. In general, the higher the ratio, the better the fuel in terms of flammability, stability, and CO emissions. However, NOx is not sensitive to H_2/CO ratio because both H_2 and CO have a similar stoichiometric flame temperature (refer to p. 28 of Reference 1).

The upper-to-lower flammability limit ratio (U/L FLR) is a key fuel property that is often used as a gauge for fuel evaluation (typical range in the order of 3 to 6). When U/L FLR is high, there is a wide range of fuel to air ratio, bounded by the high (rich) flammability limit and the low (lean) flammability limit, that can sustain a flame. In other words, flame can propagate through local fuel air mixtures of wide range of stoichiometry. On the other hand, if U/L FLR falls below a certain value, flame will extinguish as soon as it propagates through local fuel air mixtures outside the narrow flammability limits. Referring to Figure 5, the U/L FLR was found to be fairly close to the planned values for most test points. For the other's, the measured U/L FLR was within 20% higher than the planned values. All points were within the typically expected range.

Another key fuel property is the volumetric LHV of the fuel, or the volumetric LHV of the equivalent fuel when diluent injection is applied (typical $LHV_{(fuel+diluent)}$ range in the order of 200 to 400 Btu/SCF). When $LHV_{(fuel+diluent)}$ becomes too low (in the order of 100 Btu/SCF or less), CO and UHC emissions will be the first sign of combustion problem. As illustrated in Figure 5, the LHV measured was lower than the planned but within 80% of the expected value for all test points.

It is remarkable that for test point tp9, the $LHV_{(fuel+diluent)}$ of the equivalent fuel was at 75 Btu/SCF, considerably lower than the planned value at 89 Btu/SCF. The diluent-to-fuel ratio simulated closely the planned value, but the LHV of the blended fuel itself was only 84% of the LHV of the Case 2 gas. Despite the extremely low volumetric LHV of this blended fuel, its U/L FLR was within 3% of what was planned. This can be explained by the fact that the relatively higher H2 level (hence higher H_2 to CO ratio) in the blended fuel was able to offset the negative effect of lower volumetric LHV. This test case would have been a strong piece of evidence to suggest that the combustor can burn fuel even more inferior to the EECP Case 2 fuel. However, there is another factor that needs to be considered--the overall equivalence ratio.

Referring to Table 9, the overall equivalence ratio for all the test points measured were equal or less than 0.5. Typically the primary combustion zone is about twice as rich as the overall stoichiometry (refer to p. 23 of Reference 1), implying the primary combustion zone would have its equivalence ratio roughly equal or less than one. In a global sense, the primary combustion zone should have enough air to burn the fuel. However, for the two test points with Case 2 gas, the planned overall equivalence ratio (ratio between the actual fuel air ratio and the fuel air ratio at stoichiometric condition) was around 0.6, indicating that the primary combustion zone would be slightly rich, with an equivalence ratio of about 1.2. It is not clear whether this would result in any CO or UHC burn out problem. Since none of the test points were run at an overall equivalence ratio greater than 0.5, further testing would be necessary to evaluate these Case 2 gas test points originally planned with high overall equivalence ratios.

It is important to point out that if the amount of nitrogen diluent injection in these two cases can be reduced, the overall equivalence ratio will decrease to a more favorable level and CO emission would not be an issue. As will be discussed later, the NOx emissions for these test cases would be extremely low and would still be acceptable if the amount of diluent injection was reduced.

Table 9. Low Btu gas fuel properties comparison, measured versus planned

	Test point	Fuel type	Load condition	N2/LBtu fuel ratio	LHV fuel, Btu/lb	LHV fuel, Btu/SCF	U/L FLR (fuel only)	LHV (fuel+diluent), Btu/lb	LHV (fuel+diluent), Btu/SCF	U/L FLR (fuel+diluent)	H2/CO ratio	Est. stoi fuel+diluent/air ratio	Overall equivalence ratio
measured	tp5	-	-	0.00	2315	149	6.02	2315	149	6.02	1.40	0.674	0.431
planned	5	case 5b	100%	0.00	2483	165	5.84	2483	165	5.84	0.86	0.645	0.443
ratio				1.00	0.93	0.90	1.03	0.93	0.90	1.03	1.64	1.04	0.97
measured	tp5a	-	-	0.00	2539	157	6.46	2539	157	6.46	1.48	0.614	0.473
planned	5	case 5b	100%	0.00	2483	165	5.84	2483	165	5.84	0.86	0.645	0.443
ratio				1.00	1.02	0.95	1.11	1.02	0.95	1.11	1.72	0.95	1.07
measured	tp6	-	-	0.54	2710	162	6.80	1757	113	4.81	1.60	0.884	0.501
planned	6	case 5b	100%	0.50	2483	165	5.84	1655	114	4.09	0.86	0.968	0.496
ratio				1.08	1.09	0.98	1.17	1.06	0.99	1.18	1.87	0.91	1.01
measured	tp7	-	-	0.74	2308	149	6.08	1330	91	3.79	1.49	1.169	0.407
planned	-	case 5b	-	0.75	2483	165	5.84	1419	99	3.56	0.86	-	-
ratio				0.98	0.93	0.90	1.04	0.94	0.92	1.07	1.74	-	-
measured	tp8	-	-	1.19	2570	158	6.55	1175	79	3.40	1.55	1.323	0.396
planned	7	case 5b	100%	0.93	2483	165	5.84	1286	90	3.26	0.86	1.246	0.491
ratio				1.28	1.04	0.96	1.12	0.91	0.88	1.04	1.81	1.06	0.81
measured	tp9	-	-	1.05	2230	142	6.37	1088	75	3.37	1.45	1.456	0.367
planned	9	case 2	100%	1.03	2610	169	6.21	1286	89	3.28	0.75	1.275	0.612
ratio				1.02	0.85	0.84	1.02	0.85	0.84	1.03	1.94	1.14	0.60
measured	tp10	-	-	0.74	2346	148	6.46	1345	90	3.97	1.33	1.184	0.378
planned	8	case 2	100%	0.94	2610	169	6.21	1345	93	3.42	0.75	1.218	0.599
ratio				0.79	0.90	0.88	1.04	1.00	0.98	1.16	1.77	0.97	0.63
measured	tp11	-	-	0.60	1923	133	5.56	1202	85	3.64	1.56	1.295	0.413
planned	12	case 5b	50%	0.97	2483	165	5.84	1260	88	3.20	0.86	1.271	0.435
ratio				0.62	0.77	0.81	0.95	0.95	0.97	1.14	1.82	1.02	0.95
measured	tp12	-	-	0.00	2144	143	5.79	2144	143	5.79	1.40	0.728	0.453
planned	10	case 5b	50%	0.00	2483	165	5.84	2483	165	5.84	0.86	0.645	0.387
ratio				1.00	0.86	0.87	0.99	0.86	0.87	0.99	1.64	1.13	1.17
measured	tp13	-	-	0.00	2413	157	6.07	2413	157	6.07	1.23	0.651	0.081
planned	11	case 5b	FSNL	0.00	2483	165	5.84	2483	165	5.84	0.86	0.645	0.155
ratio				1.00	0.97	0.95	1.04	0.97	0.95	1.04	1.44	1.01	0.52

Note: U/L FLR = upper-to-lower flammability limit ratio

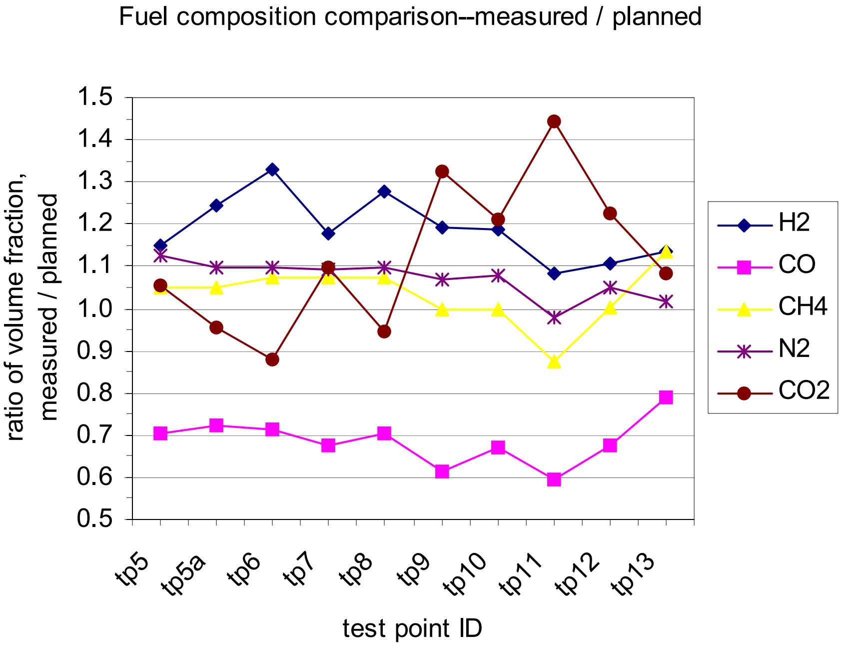


Figure 4. Comparison of fuel compositions of low Btu blended fuels between measured and planned

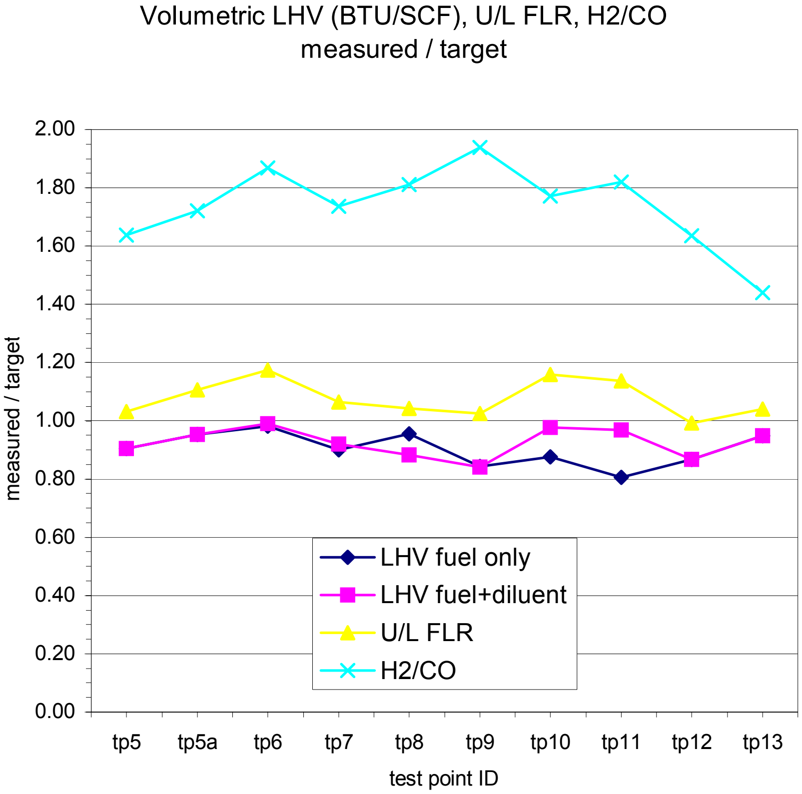


Figure 5. Comparison of volumetric LHV, U/L FLR, and H_2/CO ratio of low Btu blended fuels between measured and planned

4.2. Combustor pressure drop and velocity between flow sleeve and liner

The combustor pressure drop is defined as (Pcd-Pcc)/Pcd, where Pcd is the total pressure inside compressor discharge casing and Pcc is the total pressure at the exit of the combustor in pounds per square inch atmosphere (psia). This parameter was measured for all the test points. The lowest pressure drop was still acceptable for the 6FA machine. Also measured was the velocity distribution in circumferential direction in the annulus space between the flow sleeve and liner. These velocity measurements were taken by Kiel probes installed at designated axial locations. Except for a few outliers circumferential variation of velocity is less than ± 10%. It should be noted that the velocity follows a similar trend of the combustor pressure drop as it varies among the test points.

The data for Pcd, combustor pressure drop, and the Kiel probe differential pressure (equal to measured total pressure minus measured static pressure), from which the velocity between flow sleeve and liner is derived, were examined. The measurements for the velocity at axial locations near head end surface show a much wider variation (40 to 60%) in the circumferential direction. The measurement of Kiel probe number 7 in particular was discarded because it registered a negative differential pressure and the velocity was not calculated. The large variation in velocity can be attributed to the prototype hardware used in the test. The flow sleeve was modified for previous test programs with parts cut away near the head end. The non-uniform geometry of the flow sleeve near the head end is believed to be the cause of the velocity spread.

4.3. Liner Metal Temperatures

The liner was instrumented with 42 thermocouples at various axial and circumferential locations. These thermocouples were layout in a pattern to capture the hot spot regions of the liner. This liner was not coated with thermal boundary coating (TBC), as would be in a production liner. Even without TBC on the liner, the liner metal temperatures are within acceptable level for normal liner life. Temperature gradient between the thermocouples was also calculated along the axial direction. For all test points, low Btu and natural gas alike, temperature gradient is well within acceptable operation limit. Nevertheless, liner metal temperature and gradient are expected to increase if the test points were run to the planned combustor exit temperature.

4.4. Combustor Exit Temperature Profiles

The combustor exit temperature profiles were measured with a thermocouple matrix at the combustor exit. These thermocouple readings were corrected for radiation. The basic shape of the profile remains the same for both the low Btu gas and natural gas test points. A local minimum of temperature was observed around mid span, and is typical of multi nozzle combustor design.

4.5. Combustion Dynamics

Combustion dynamics were monitored at the following locations:

- liner
- feed pipe for low Btu gas
- feed pipe for natural gas
- feed pipe for diluent injection

The dynamic data, however, was not connected to the main database of the data acquisition system. The results were printed out only in hardcopy format. The level of combustion dynamics was measured as the amplitude of pressure fluctuation inside the liner of the combustor. Combustion dynamics for all test points was lower than the limit beyond which life of combustor components would be adversely affected. This is consistent with experience of this type of multi-nozzle quiet combustor (MNQC).

4.6. Emissions

One of the test objectives is to evaluate the effectiveness of diluent injection for NOx abatement. Test data show that the ISO NOx corrected to 15% O_2 follows an exponential relationship with adiabatic stoichiometric flame temperature (Tf,ad,stoi), which is consistent with past experience. The predictions for the planned test points for both the low Btu gas and natural gas were also compared with the data. At extremely low NOx levels, the predictions, which are based on previous experience, appear to exhibit a sharper decline with Tf,ad,stoi compared to the data. This would suggest the slope of the NOx correlation derived from this test is slightly smaller compared to past experience. However, more data collected from a multiple of tests would be required to get a good statistical average to confirm or reject this conjecture. Note that test point tp13 is excluded from the NOx correlation because its combustion efficiency dropped below 100% due to incomplete combustion and the equilibrium calculation for Tf,ad,stoi would not be accurate.

It is important to emphasize that this set of NOx data represents test points of low Btu gas with various fuel compositions. It should also be noted that the low Btu gas test points all have remarkably low NOx level, many of the test points have single digit NOx levels (i.e., NOx level less than 10 ppm). The effect of nitrogen injection on NOx can also be observed when the measured NOx data and NOx predictions of the planned test points are plotted against N_2/fuel ratio for the low Btu gas. In this case, an exponential correlation is observed and is considered appropriate.

Since the actual test point conditions deviated from what were planned, additional cycle deck calculations were performed using actual test point conditions. The cycle conditions were set to match the measured combustor exit temperature, fuel composition, fuel to air ratio, and diluent to fuel ratio. The cycle deck predictions for the actual test conditions were compared with the measured data. The comparison showed that the cycle deck prediction for NOx is fairly accurate and conservative.

The results on CO and UHC were examined for the low Btu gas and natural gas test points respectively. Except for the FSNL point of the low Btu gas and the 30% load point of the natural gas, where combustor exit temperature was distinctively lower than that of the other test points, CO and UHC were well below 10 ppm. Even at very low combustor exit temperatures, CO was still below 10 ppm and the UHC level was still negligible.

5. Conclusions/Recommendations

The combustion test of simulated EECP low Btu fuels gas was conducted on May 7-8, 2002 in the GTTL of GE Power Systems in Greenville, South Carolina. The major objective of the test was to validate that the full range operation of current combustor design of a GE PG6101 (6FA) 60 Hz heavy duty gas turbine using a simulation of the low Btu-mixture of the proposed EECP. The low Btu-mixture includes gasifier synthesis gas resulting from the EECP coal/coke gasification diluted with F-T tailgas, AGR offgas. This test at GTTL has confirmed satisfactory operation of the GE 6FA IGCC combustor using low Btu fuels with diluent injection for control of NOx emissions that are typical for the EECP concept.

The test was conducted with a single GE 6FA IGCC type combustor mounted on a test stand designed to simulate the inlet and outlet interface with the combustor. TES identified twelve different EECP cases in a test matrix (see Appendix). Two low Btu fuels, bracketing the twelve cases, were selected to investigate the effect of fuel composition. From these two cases, GEPS and ChevronTexaco defined a set of test points. The test points included two additional synthesis gas fuel test points and four natural gas test points for the backup fuel. Nitrogen (N_2) was injected through the head end of the combustor to study its effect on NOx abatement. The general conclusions drawn from this test program evaluation are:

1. Low Btu EECP fuels are viable for GE gas turbine applications
2. All test points attempted showed no sign of combustion related problems that may produce excessive emissions or adversely impact the normal life of component parts.
3. Low NOx and low CO emissions are possible with N_2 injection for 6FA application.
4. Less than 10 ppm of NOx and CO emissions at 6FA full load conditions appear feasible with an appropriate amount of nitrogen injection as in the proposed EECP concept.

Although a number of test facility issues related to the blended fuel flow control and measurement system have prevented the precise setting of the test point conditions as planned, the overall test is considered successful. The specific major findings of the test are:

1. Issues on simulating the test conditions for the low Btu gas portion of the test have been identified through data reduction and facility inspection, and have been accounted for in the evaluation of the data.
    - Volumetric LHV of the low Btu blended fuel and the equivalent fuel (diluent injection included) was lower than what was originally planned.
    - H2/CO ratio of the blended fuel was higher than its planned value.
    - Combustor exit temperature was lower than its planned value.

2. Test point conditions for the natural gas portion of the test were successfully simulated.

3. All the test points attempted show no sign of any combustion related problem.
4. The effect of diluent injection was demonstrated in the NOx correlation, which is consistent with previous experience. The measured NOx also compared well with cycle deck predictions based on actual test conditions.

5. The higher than expected H2/CO ratio should have increased the flammability range of the equivalent fuel. However, the lower than expected volumetric LHV reduced flammability. As a result, the upper-to-lower flammability ratio (U/L FLR) of the equivalent fuel was kept within 18% of the planned value, with majority of the test points within a few percent. The lowest value for U/L FLR originally planned was 3.2. Lowest U/L FLR successfully tested was 3.37. Both sets of numbers are well within the past experience on satisfactory low Btu fuel combustion.

6. Highest overall equivalence ratio planned was about 0.6 and was applicable to the two test points with Case 2 gas. The highest overall equivalence ratio tested was 0.5. For high overall equivalence ratio, there is a concern that the primary zone may be too rich for CO and UHC burn out. However, the combustor exit temperatures for the Case 2 gas test points are within the range where CO and UHC were measured at 10 ppm or less.

7. Equivalent fuel with LHV as low as 75 Btu/SCF (16% below the planned value, see Table 9) found to burn successfully. However, combustor exit temperature in this case was 16% lower than planned value. The blended fuel flow rate was lower than what it should be for simulating the combustor exit temperature as planned and the overall equivalence ratio was only 0.37. It is not clear if this fuel can still burn without any CO problem if the overall equivalence ratio has to be raised to attain a higher combustor exit temperature.

8. Combustion dynamics were within the acceptable limits.

9. The liner temperature and flow distribution were satisfactory.

10. Combustor pressure drop was consistent with design requirements.

11. The combustor operated satisfactorily with performance as designed.

6. Bibliography

1) Battista, R. A. and Dudley, J. C., Heavy Duty Gas Turbine Combustion Tests Using Simulated Low-Btu Coal Gas, Final Report, DOE-MC/27221-1, June 30, 1994.

7. List of Acronyms and Abbreviations:

AGR	Acid Gas Recovery
ASME	American Society of Mechanical Engineers
ASU	Air Separation Unit
Btu	British Thermal Unit
C_2H_6	Ethane
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
DOE	Department of Energy
EECP	Early Entrance Co production Plant
EPA	Environmental Protection Agency
F-T	Fischer-Tropsch
FTPU	Fischer-Tropsch Product Upgrading
GE	General Electric
GEPS	General Electric Power Systems
GT	Gas Turbine
GTTL	GE Gas Turbine Technology Laboratory
h	Hour
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulfide
HHV	Higher Heating Value
HRSG	Heat Recovery Steam Generator
Hz	Hertz
ID	Identification
IGCC	Integrated Gasification Combined Cycle
KBR	Kellogg Brown & Root
Lb	Pound
LBtu	Low British Thermal Unit
LHV	Lower Heating Value
MM	Million
MNQC	Multi-Nozzle Quiet Combustor
N_2	Nitrogen
NG	Natural Gas
NOx	Nitrous oxide
O_2	Oxygen
Pcc	Combustor Exit Pressure
Pcd	Compressor Discharge Pressure
ppm	Parts per million
psia	Pounds per square inch atmosphere
RD&T	Research, Development, & Testing
scf	Standard cubic feet
SIN	Stage 1 Nozzle
SO_2	Sulfur dioxide

SRU	Sulfur Recovery Unit
SWS	Sour Water Stripper
TBC	Thermal Boundary Coating
TC	Thermocouple
TDC	Top Dead Center
TES	Texaco Energy Systems LLC
Tf,ad,stoi	Adiabatic stoichiometric flame temperature
TP	Combustor Transition Piece
UHC	Unburned Hydrocarbons
U/L FLR	Upper to Lower Flammability Limit

Appendix

Cases	Case 1: NOC Base Case			Case 2*: NOC w/FT Down			Case 3: Gasifier Design Base Case			Case 4*: Gasifier Design Case w/FT Down		
	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)
Fuel Gas Mixture to GT (AGR Syngas + F-T TG + FTPU Purge)												
H2O	24.01	0.19%	0.000	22.24	0.18%	0.000	25.59	0.20%	0.000	23.86	0.19%	0.000
H2	2928.84	23.76%	304.327	3055.84	24.42%	317.523	3110.08	24.47%	323.160	3177.46	24.66%	330.161
CO	3860.41	31.32%	469.541	4031.90	32.23%	490.399	3779.49	29.74%	459.698	3933.64	30.53%	478.448
CO2	2443.48	19.82%	0.000	2108.57	16.85%	0.000	2699.44	21.24%	0.000	2443.32	18.97%	0.000
AR	25.87	0.21%	0.000	0.00	0.00%	0.000	27.28	0.21%	0.000	0.00	0.00%	0.000
N2	2992.69	24.28%	0.000	3286.33	26.27%	0.000	3017.56	23.75%	0.000	3300.29	25.62%	0.000
C1	23.66	0.19%	8.164	5.53	0.04%	1.908	20.59	0.16%	7.106	3.30	0.03%	1.139
C2	9.23	0.07%	5.673	0.00	0.00%	0.000	9.06	0.07%	5.563	0.00	0.00%	0.000
C3	6.89	0.06%	6.050	0.00	0.00%	0.000	6.76	0.05%	5.936	0.00	0.00%	0.000
C4	4.62	0.04%	5.283	0.00	0.00%	0.000	4.53	0.04%	5.181	0.00	0.00%	0.000
C5	3.01	0.02%	4.235	0.00	0.00%	0.000	2.96	0.02%	4.163	0.00	0.00%	0.000
C6	1.94	0.02%	3.247	0.00	0.00%	0.000	1.92	0.02%	3.206	0.00	0.00%	0.000
C7	1.00	0.01%	1.930	0.00	0.00%	0.000	0.99	0.01%	1.924	0.00	0.00%	0.000
C8	0.36	0.00%	0.791	0.00	0.00%	0.000	0.36	0.00%	0.801	0.00	0.00%	0.000
C9	0.13	0.00%	0.328	0.00	0.00%	0.000	0.14	0.00%	0.340	0.00	0.00%	0.000
C10+	0.04	0.00%	0.115	0.00	0.00%	0.000	0.05	0.00%	0.141	0.00	0.00%	0.000
H2S	0.57	0.00%	0.128	0.64	0.01%	0.142	0.77	0.01%	0.172	0.85	0.01%	0.190
COS	0.08	0.00%	0.020	0.09	0.00%	0.022	0.18	0.00%	0.041	0.20	0.00%	0.046
NH3	0.00	0.00%	0.000	0.00	0.00%	0.000	0.00	0.00%	0.000	0.00	0.00%	0.000
MDEA	0.01	0.00%	0.000	0.02	0.00%	0.000	0.02	0.00%	0.000	0.02	0.00%	0.000
O2	0.28	0.00%	0.000	0.31	0.00%	0.000	0.28	0.00%	0.000	0.31	0.00%	0.000
Total	12327.13	100.00%	809.832	12511.48	100.00%	809.995	12708.04	100.00%	817.431	12883.25	100.00%	809.984
LHV (BTU/SCF)		173.11			170.59			169.50			165.67	
HHV (BTU/SCF)		185.78			182.95			182.48			178.13	
ASU Diluent N2 to GT												
H2O	12.22	0.12%	0.000	12.22	0.12%	0.000	12.50	0.12%	0.000	12.50	0.12%	0.000
CO2	5.09	0.05%	0.000	5.09	0.05%	0.000	5.21	0.05%	0.000	5.21	0.05%	0.000
AR	54.99	0.54%	0.000	54.99	0.54%	0.000	56.26	0.54%	0.000	56.26	0.54%	0.000
N2	10024.15	98.43%	0.000	10024.15	98.43%	0.000	10254.93	98.43%	0.000	10254.93	98.43%	0.000
O2	87.58	0.86%	0.000	87.58	0.86%	0.000	89.60	0.86%	0.000	89.60	0.86%	0.000
Total	10184.04	100.00%	0.000	10184.04	100.00%	0.000	10418.50	100.00%	0.000	10418.50	100.00%	0.000
Fuel gas mixture + ASU Diluent N2 to GT												
Total Flow	22511.17		809.832	22695.52		809.995	23126.53		817.431	23301.75		809.984
LHV (BTU/SCF)		94.8			94.0			93.1			91.6	
HHV (BTU/SCF)		101.7			100.9			100.3			98.5	

* Note: For Cases 2 & 4, syngas flowrates were increased to load GT.

Independent occurrences were identified for each process section of the EECP that would influence the gas turbine feed gas (in terms of rate and composition). A probability was assigned to each of these occurrences.

In the gasification section, two scenarios are considered. The gasifier may generate syngas at the normal operating conditions (NOC) producing the designed composition and flow-rate. This is the base case for EECP design. The second scenario would be that the operations might generate syngas at design conditions (Design), in which case the syngas produced would have a different flow-rate and composition.

For the Fischer-Tropsch Synthesis section, three scenarios are considered. Once again there is a base case that will produce normal tail gas to the gas turbine. Two other extreme scenarios are considered, zero conversion when the unit is down and high conversion when the performance approaches 100% CO conversion.

In addition to the base case in the Acid Gas Removal section, two other scenarios are considered loss of N2 from ASU and lower than expected N2 stripping efficiency.

For the F-T Product Upgrading section, in addition to base case, the alternative scenario considered where the FTPU operates where the light end generation is very large causing a higher recycle gas purge rate to gas turbine.

For each of the scenarios described above, a probability of occurrence was assigned and listed in the table below.

Section	**Occurrences**	**Probability**
Gasification	NOC	75%
	Design	25%
Fischer Tropsch Synthesis	Base Case	50%
	Down	40%
	High Conversion	10%
Acid Gas Removal	Base Case	79%
	Loss of N2	1%
	Reduced Stripping Efficiency	20%
F-T Product Upgrading	Base Case	90%
	Higher Purge Rate	10%

Cases were developed using the combinations of the scenarios listed above. The probability of the each case was then calculated from the products of the probability of the occurrences. These values are listed in the table below. The variations in the Gas Turbine feed produce by each case and its probability will be considered when designing the Gas Turbine RD&T activities.

Appendix (Cont.)

Cases	**Probability**
1. Base Case – NOC case	26.7%
2. FT down - NOC case	21.3%
3. Base Case Design Case	8.9%
4. FT down – Design case	7.1%
5a. FT w. 100% conversion – NOC Case	5.3%
5b. FT w. 100% conversion – Design Case	1.8%
6a. AGR Loss of N2 – NOC Case	0.3%
6b. AGR Loss of N2 – Design Case	0.1%
7a. AGR Reduced Stripping Eff. – NOC Case	6.8%
7b. AGR Reduced Stripping Eff. – Design case	2.3%
8a. FTPU purge rate is high – NOC Case	3%
8b. FTPU purge rate is high – Design case	1%

The above 12 cases cover the 85 % of all the probable cases. The combinations of above scenario could be considered, but the probability of those occurrences would be low.

After looking at the probability of each case, the team decided to drop cases 6a, and 6b. The team decided to add two additional cases, i.e. 9a. NOC with high FT throughput and 9b. Design with high FT throughput.

Please note NOC case and Design case for above refers to Gasifications sections cases.

The simulated gas streams for above 12 cases are as follows:

Appendix (Cont.)

Cases	Case 1: NOC Base Case			Case 2*: NOC w/FT Down			Case 3: Gasifier Design Base Case			Case 4*: Gasifier Design Case w/FT Down		
	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)
Fuel Gas Mixture to GT (AGR Syngas + F-T TG + FTPU Purge)												
H2O	24.01	0.19%	0.000	22.24	0.18%	0.000	25.59	0.20%	0.000	23.86	0.19%	0.000
H2	2928.84	23.76%	304.327	3055.84	24.42%	317.523	3110.08	24.47%	323.160	3177.46	24.66%	330.161
CO	3860.41	31.32%	469.541	4031.90	32.23%	490.399	3779.49	29.74%	459.698	3933.64	30.53%	478.448
CO2	2443.48	19.82%	0.000	2108.57	16.85%	0.000	2699.44	21.24%	0.000	2443.32	18.97%	0.000
AR	25.87	0.21%	0.000	0.00	0.00%	0.000	27.28	0.21%	0.000	0.00	0.00%	0.000
N2	2992.69	24.28%	0.000	3286.33	26.27%	0.000	3017.56	23.75%	0.000	3300.29	25.62%	0.000
C1	23.66	0.19%	8.164	5.53	0.04%	1.908	20.59	0.16%	7.106	3.30	0.03%	1.139
C2	9.23	0.07%	5.673	0.00	0.00%	0.000	9.06	0.07%	5.563	0.00	0.00%	0.000
C3	6.89	0.06%	6.050	0.00	0.00%	0.000	6.76	0.05%	5.936	0.00	0.00%	0.000
C4	4.62	0.04%	5.283	0.00	0.00%	0.000	4.53	0.04%	5.181	0.00	0.00%	0.000
C5	3.01	0.02%	4.235	0.00	0.00%	0.000	2.96	0.02%	4.163	0.00	0.00%	0.000
C6	1.94	0.02%	3.247	0.00	0.00%	0.000	1.92	0.02%	3.206	0.00	0.00%	0.000
C7	1.00	0.01%	1.930	0.00	0.00%	0.000	0.99	0.01%	1.924	0.00	0.00%	0.000
C8	0.36	0.00%	0.791	0.00	0.00%	0.000	0.36	0.00%	0.801	0.00	0.00%	0.000
C9	0.13	0.00%	0.328	0.00	0.00%	0.000	0.14	0.00%	0.340	0.00	0.00%	0.000
C10+	0.04	0.00%	0.115	0.00	0.00%	0.000	0.05	0.00%	0.141	0.00	0.00%	0.000
H2S	0.57	0.00%	0.128	0.64	0.01%	0.142	0.77	0.01%	0.172	0.85	0.01%	0.190
COS	0.08	0.00%	0.020	0.09	0.00%	0.022	0.18	0.00%	0.041	0.20	0.00%	0.046
NH3	0.00	0.00%	0.000	0.00	0.00%	0.000	0.00	0.00%	0.000	0.00	0.00%	0.000
MDEA	0.01	0.00%	0.000	0.02	0.00%	0.000	0.02	0.00%	0.000	0.02	0.00%	0.000
O2	0.28	0.00%	0.000	0.31	0.00%	0.000	0.28	0.00%	0.000	0.31	0.00%	0.000
Total	12327.13	100.00%	809.832	12511.48	100.00%	809.995	12708.04	100.00%	817.431	12883.25	100.00%	809.984
LHV (BTU/SCF)		173.11			170.59			169.50			165.67	
HHV (BTU/SCF)		185.78			182.95			182.48			178.13	
ASU Diluent N2 to GT												
H2O	12.22	0.12%	0.000	12.22	0.12%	0.000	12.50	0.12%	0.000	12.50	0.12%	0.000
CO2	5.09	0.05%	0.000	5.09	0.05%	0.000	5.21	0.05%	0.000	5.21	0.05%	0.000
AR	54.99	0.54%	0.000	54.99	0.54%	0.000	56.26	0.54%	0.000	56.26	0.54%	0.000
N2	10024.15	98.43%	0.000	10024.15	98.43%	0.000	10254.93	98.43%	0.000	10254.93	98.43%	0.000
O2	87.58	0.86%	0.000	87.58	0.86%	0.000	89.60	0.86%	0.000	89.60	0.86%	0.000
Total	10184.04	100.00%	0.000	10184.04	100.00%	0.000	10418.50	100.00%	0.000	10418.50	100.00%	0.000
Fuel gas mixture + ASU Diluent N2 to GT												
Total Flow	22511.17		809.832	22695.52		809.995	23126.53		817.431	23301.75		809.984
LHV (BTU/SCF)		94.8			94.0			93.1			91.6	
HHV (BTU/SCF)		101.7			100.9			100.3			98.5	

* Note: For Cases 2 & 4, syngas flowrates were increased to load GT.

Appendix (Cont.)

Cases	Case 5a: NOC w/FT High Conversion			Case 5b: Gasifier Design Case w/FT High Conversion			Case 7a: NOC w/AGR Reduced Stripping Efficiency			Case 7b: Gasifier Design Case w/AGR Reduced Stripping Efficiency		
	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)
Fuel Gas Mixture to GT (AGR Syngas + F-T TG + FTPU Purge)												
H2O	21.51	0.18%	0.000	23.00	0.19%	0.000	24.01	0.20%	0.000	25.59	0.20%	0.000
H2	2775.76	23.05%	288.421	2939.61	23.72%	305.446	2928.84	24.12%	304.327	3110.08	24.91%	323.160
CO	3657.35	30.37%	444.843	3554.38	28.68%	432.319	3860.41	31.79%	469.541	3779.49	30.27%	459.698
CO2	2513.75	20.87%	0.000	2778.63	22.42%	0.000	2260.83	18.62%	0.000	2478.82	19.85%	0.000
AR	25.78	0.21%	0.000	27.18	0.22%	0.000	25.87	0.21%	0.000	27.28	0.22%	0.000
N2	2992.58	24.85%	0.000	3017.43	24.35%	0.000	2992.69	24.64%	0.000	3017.56	24.16%	0.000
C1	26.29	0.22%	9.073	23.52	0.19%	8.117	23.66	0.19%	8.164	20.59	0.16%	7.106
C2	10.57	0.09%	6.495	10.55	0.09%	6.483	9.23	0.08%	5.673	9.06	0.07%	5.563
C3	7.75	0.06%	6.811	7.74	0.06%	6.796	6.89	0.06%	6.050	6.76	0.05%	5.936
C4	5.16	0.04%	5.901	5.15	0.04%	5.882	4.62	0.04%	5.283	4.53	0.04%	5.181
C5	3.05	0.03%	4.294	3.03	0.02%	4.269	3.01	0.02%	4.235	2.96	0.02%	4.163
C6	1.60	0.01%	2.668	1.58	0.01%	2.642	1.94	0.02%	3.247	1.92	0.02%	3.206
C7	0.52	0.00%	1.011	0.51	0.00%	0.995	1.00	0.01%	1.930	0.99	0.01%	1.924
C8	0.10	0.00%	0.212	0.09	0.00%	0.206	0.36	0.00%	0.791	0.36	0.00%	0.801
C9	0.02	0.00%	0.042	0.02	0.00%	0.041	0.13	0.00%	0.328	0.14	0.00%	0.340
C10+	0.00	0.00%	0.009	0.00	0.00%	0.008	0.04	0.00%	0.115	0.05	0.00%	0.141
H2S	0.57	0.00%	0.128	0.77	0.01%	0.172	0.57	0.00%	0.128	0.77	0.01%	0.172
COS	0.08	0.00%	0.020	0.18	0.00%	0.041	0.08	0.00%	0.020	0.18	0.00%	0.041
NH3	0.00	0.00%	0.000	0.00	0.00%	0.000	0.00	0.00%	0.000	0.00	0.00%	0.000
MDEA	0.01	0.00%	0.000	0.02	0.00%	0.000	0.01	0.00%	0.000	0.02	0.00%	0.000
O2	0.28	0.00%	0.000	0.28	0.00%	0.000	0.28	0.00%	0.000	0.28	0.00%	0.000
Total	12042.76	100.00%	769.928	12393.68	100.00%	773.418	12144.48	100.00%	809.832	12487.43	100.00%	817.431
LHV (BTU/SCF)		168.47			164.44			175.71			172.49	
HHV (BTU/SCF)		180.82			177.08			188.58			185.70	
ASU Diluent N2 to GT												
H2O	12.22	0.12%	0.000	12.50	0.12%	0.000	12.22	0.12%	0.000	12.50	0.12%	0.000
CO2	5.09	0.05%	0.000	5.21	0.05%	0.000	5.09	0.05%	0.000	5.21	0.05%	0.000
AR	54.99	0.54%	0.000	56.26	0.54%	0.000	54.99	0.54%	0.000	56.26	0.54%	0.000
N2	10024.15	98.43%	0.000	10254.93	98.43%	0.000	10024.15	98.43%	0.000	10254.93	98.43%	0.000
O2	87.58	0.86%	0.000	89.60	0.86%	0.000	87.58	0.86%	0.000	89.60	0.86%	0.000
Total	10184.04	100.00%	0.000	10418.50	100.00%	0.000	10184.04	100.00%	0.000	10418.50	100.00%	0.000
Fuel gas mixture + ASU Diluent N2 to GT												
Total Flow	22226.80		769.928	22812.17		773.418	22328.52		809.832	22905.92		817.431
LHV (BTU/SCF)		91.3			89.3			95.6			94.0	
HHV (BTU/SCF)		98.0			96.2			102.6			101.2	

* Note: For Cases 2 & 4, syngas flowrates were increased to load GT.

Appendix (Cont.)

Cases	Case 8a: NOC w/FTPU High Purge Rate			Case 8b: Gasifier Design Case w/FTPU High Purge Rate			Case 9a: NOC High FT Flow Through Rate			Case 9b: Gasifier Design Case High FT Flow Through Rate		
	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)	LBMOL/HR	vol%	MMBtu/h (LHV Basis)
Fuel Gas Mixture to GT (AGR Syngas + F-T TG + FTPU Purge)												
H2O	24.08	0.19%	0.000	25.66	0.20%	0.000	23.30	0.20%	0.000	24.77	0.21%	0.000
H2	2973.66	24.02%	308.985	3154.91	24.72%	327.817	2755.98	23.57%	286.365	2940.77	24.41%	305.567
CO	3860.51	31.18%	469.552	3779.59	29.61%	459.710	3634.50	31.08%	442.064	3558.50	29.54%	432.820
CO2	2446.09	19.76%	0.000	2702.05	21.17%	0.000	2410.12	20.61%	0.000	2632.42	21.85%	0.000
AR	25.87	0.21%	0.000	27.28	0.21%	0.000	31.04	0.27%	0.000	32.73	0.27%	0.000
N2	2992.74	24.17%	0.000	3017.61	23.64%	0.000	2777.79	23.76%	0.000	2801.48	23.25%	0.000
C1	28.80	0.23%	9.938	25.73	0.20%	8.880	26.76	0.23%	9.236	23.63	0.20%	8.155
C2	10.23	0.08%	6.283	10.05	0.08%	6.173	11.03	0.09%	6.777	10.82	0.09%	6.645
C3	7.07	0.06%	6.215	6.95	0.05%	6.101	8.25	0.07%	7.251	8.10	0.07%	7.115
C4	4.83	0.04%	5.515	4.74	0.04%	5.413	5.54	0.05%	6.328	5.43	0.05%	6.205
C5	3.17	0.03%	4.466	3.12	0.02%	4.394	3.60	0.03%	5.070	3.54	0.03%	4.984
C6	2.04	0.02%	3.408	2.01	0.02%	3.366	2.33	0.02%	3.889	2.30	0.02%	3.839
C7	1.04	0.01%	2.020	1.04	0.01%	2.014	1.19	0.01%	2.312	1.19	0.01%	2.304
C8	0.37	0.00%	0.825	0.38	0.00%	0.834	0.43	0.00%	0.948	0.44	0.00%	0.959
C9	0.14	0.00%	0.336	0.14	0.00%	0.348	0.16	0.00%	0.393	0.17	0.00%	0.408
C10+	0.04	0.00%	0.118	0.05	0.00%	0.143	0.05	0.00%	0.138	0.05	0.00%	0.148
H2S	0.57	0.00%	0.128	0.77	0.01%	0.172	0.53	0.00%	0.118	0.71	0.01%	0.159
COS	0.08	0.00%	0.020	0.18	0.00%	0.041	0.08	0.00%	0.018	0.16	0.00%	0.038
NH3	0.00	0.00%	0.000	0.00	0.00%	0.000	0.00	0.00%	0.000	0.00	0.00%	0.000
MDEA	0.01	0.00%	0.000	0.02	0.00%	0.000	0.01	0.00%	0.000	0.01	0.00%	0.000
O2	0.28	0.00%	0.000	0.28	0.00%	0.000	0.26	0.00%	0.000	0.26	0.00%	0.000
Total	12381.64	100.00%	817.808	12762.55	100.00%	825.407	11692.97	1.00	770.91	12047.49	100.00%	779.346
LHV (BTU/SCF)		174.04			170.42			173.73			170.46	
HHV (BTU/SCF)		186.91			183.59			186.47			183.57	
ASU Diluent N2 to GT												
H2O	12.22	0.12%	0.000	12.50	0.12%	0.000	12.22	0.12%	0.000	12.50	0.12%	0.000
CO2	5.09	0.05%	0.000	5.21	0.05%	0.000	5.09	0.05%	0.000	5.21	0.05%	0.000
AR	54.99	0.54%	0.000	56.26	0.54%	0.000	54.99	0.54%	0.000	56.26	0.54%	0.000
N2	10024.15	98.43%	0.000	10254.93	98.43%	0.000	10024.15	98.43%	0.000	10254.93	98.43%	0.000
O2	87.58	0.86%	0.000	89.60	0.86%	0.000	87.58	0.86%	0.000	89.60	0.86%	0.000
Total	10184.04	100.00%	0.000	10418.50	100.00%	0.000	10184.04	100.00%	0.000	10418.50	100.00%	0.000
Fuel gas mixture + ASU Diluent N2 to GT												
Total Flow	22565.68		817.808	23181.04		825.407	21877.01		770.908	22465.98		779.346
LHV (BTU/SCF)		95.5			93.8			92.9			91.4	
HHV (BTU/SCF)		102.6			101.1			99.7			98.4	

* Note: For Cases 2 & 4, syngas flowrates were increased to load GT.