Demonstrated Applicability of Hydrogen Fuel for Gas Turbines

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Abstract:

In recent years significant progress has been made in the development of market applications for hydrogen fuel use in gas turbines. These applications include integrated gasification combined cycle (IGCC) and other types of process/power plants. Development of a new application using gas turbines for significant reduction of power plant CO_2 emissions has initiated extensive efforts to expand the range of hydrogen combustion capabilities. This paper reports on leading gasification systems producing hydrogen fuel, their technology background, and the results of a recent hydrogen combustion-testing program including resultant affects on gas turbine cycles.

Testing program results show the feasibility of hydrogen use for 20-90% CO_2 emission reduction with control of NO_X emissions to below 10 ppmvd at 15% oxygen. Operating flexibility, turndown and gas turbine life criteria are also discussed. Testing program data suggest that reliability, availability and maintenance (RAM) statistics for power blocks using hydrogen fuel can be maintained at equivalent levels to those of Natural Gas power plants.

Power Plants Using Hydrogen for CO_2 Emission Abatement

Widespread concern regarding global warming has initiated numerous studies of the economics of various solutions for reducing CO_2 emissions from power plants. Many of these studies focus on removing CO_2, either in the pre-combustion process, which affects the small, high-pressure fuel stream, or in the post-combustion process, which affects the very large atmospheric exhaust stream. Pre-combustion decarbonization schemes that rely on the use of hydrogen as a gas turbine/combined cycle fuel are considered to be more economical at the current stage of combustor development. The power block cycle is usually integrated with the process plant; incorporating gasification/reforming to separate the hydrogen from the carbon and removing the carbon as CO_2 for enhanced oil recovery or sequestration.

In plants fueled by natural gas the gasification block may use air- or oxygen-blown processes and may include catalytic partial oxidation (Cat Pox). In this case the plant is referred to as an integrated reformer combined cycle (IRCC) [Figure 1]. Following the production of H_2 and CO, syngas enters shift reactor and CO_2 removal system process blocks. The shift reactor block uses water to produce CO_2 and additional hydrogen. The CO_2 removal system block separates the CO_2 for enhanced oil recovery or sequestration. The hydrogen is then used as gas turbine fuel. The blocks outlined are needed only when CO_2 reduction is required. They amount to an additional plant cost of about 45% as compared to a conventional combined cycle power plant. New configurations such as reformers using heat from conventional Pox gasification are called Gas Heated Reformers. These combinations can reduce plant cost and improve economics.

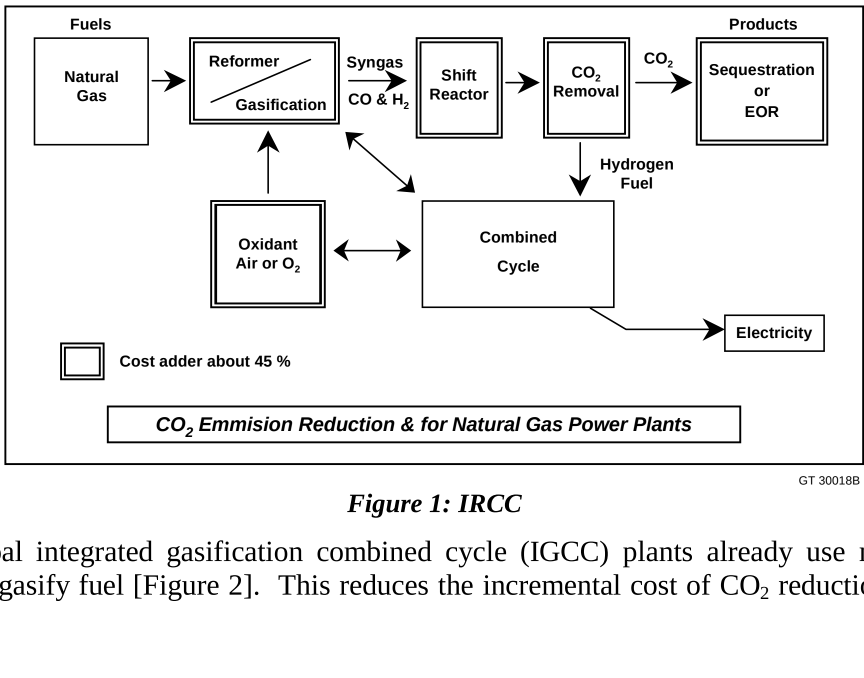

Figure 1: IRCC

Heavy oil and coal integrated gasification combined cycle (IGCC) plants already use many of the same process blocks to gasify fuel [Figure 2]. This reduces the incremental cost of CO_2 reduction. Cat Pox is not generally considered due to contaminants in heavy fuels. The blocks outlined in Figure 2 are only needed when CO_2 reduction is required, and amount to an additional plant cost of about 15%.

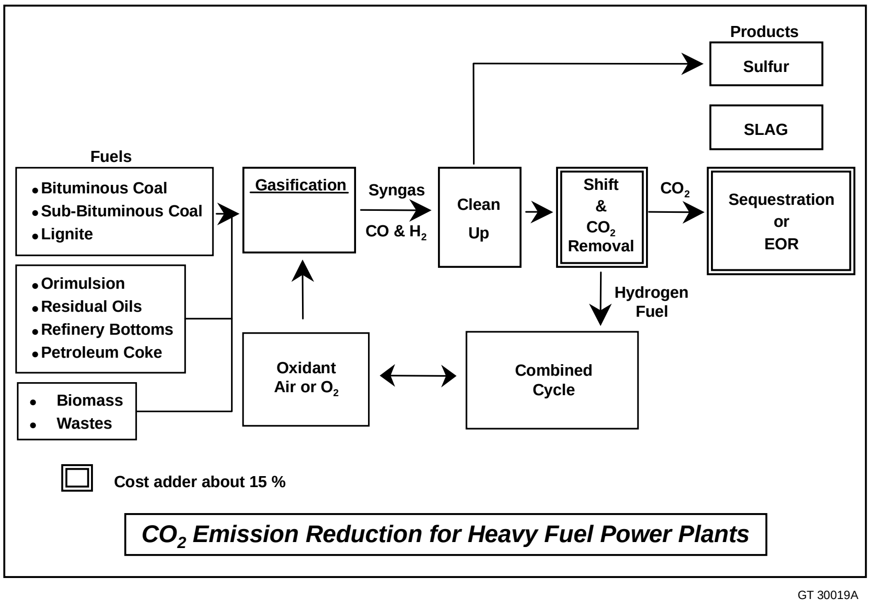

Figure 2: IGCC

Power Block/Process Block Integration

Gas turbines and gasification systems can be coupled by integrating the gas turbine with the steam- or air-side or both sides of the gasification system to improve economics.

The concept of both steam- and air-side integration is common in IGCC systems. However, there are new possibilities for integrating the gasification plant air-side with natural gas plants using auto thermal reformers (ATR) [Figure 3]. These Cat Pox processes operate at 30 bar pressure and high temperatures so integrating gas turbine air extraction with a booster compressor can be beneficial. Oxygen blown ATRs may also be used by inclusion of an Air Separation Plant (ASU). Alternatively, non-catalytic oxygen gasifiers may be used for large plants with air being supplied from the gas turbine.

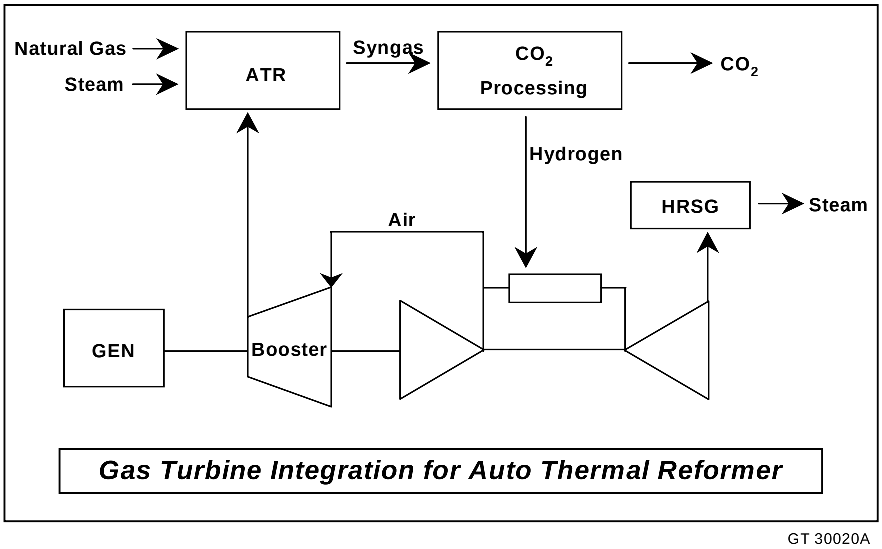

Figure 3: ATR Air Integration

Air may also be supplied from membrane separation as proposed in the Starchem Process [Figure 4]. In this process, air extracted from the gas turbine is separated into an oxygen-rich stream for syngas production and a depleted-air stream that can be returned to the gas turbine. The Starchem Process, as shown, produces methanol but the front end can also be used for CO_2 reduction cycles.

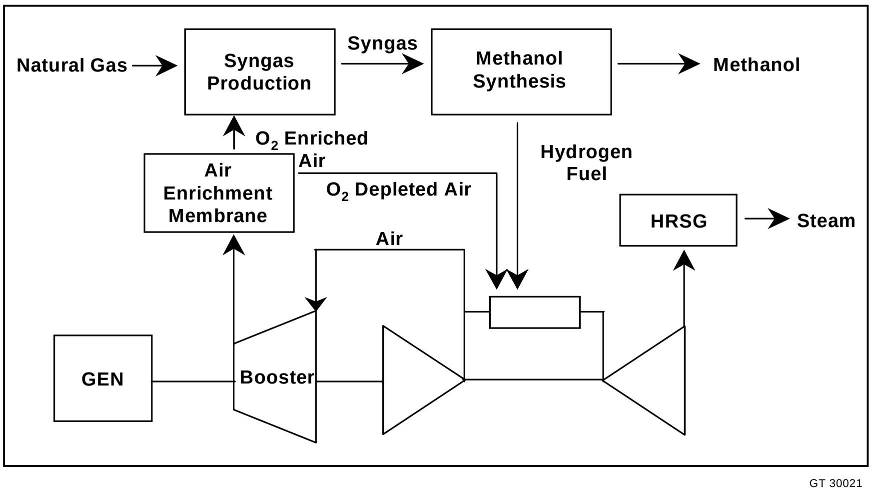

Figure 4: Starchem Process Air Integration

Optimization of these and other integration schemes can frequently produce a 20-30% improvement in economics compared with separate systems.

Hydrogen Fuel for Gas Turbines

Many existing gas turbine combined cycle (GTCC) plants, including refinery gas applications and all IGCC plants, use hydrogen-based fuels. IGCC plants use fuel ranging from 9 to 60% hydrogen by volume. Figure 5 shows the fuel constituents for plants in operation and under construction. A middle hydrogen range is shown for the IRCC plant. It is important to note that with IRCC the fuel is essentially 100% hydrogen since other combustibles are less than 2% by volume. Each of these fuels has been demonstrated successfully in full-scale lab testing and most tests were followed-up by field verification in operating units.

Syngas	PSI	Tampa	El Dorado	Pernis	Sierra Pacific	ILVA	Schwarze Pumpe	Sarlux	Fife	Exxon Singapore	Motiva Delaware	IRCC	Star Chem
H_2	24.8	37.2	35.4	34.4	14.5	8.6	61.9	22.7	34.4	44.5	32.0	46.84	40.0
CO	39.5	46.6	45.0	35.1	23.6	26.2	26.2	30.6	55.4	35.4	49.5	1.13	1.0
CH_4	1.5	0.1	0.0	0.3	1.3	8.2	6.9	0.2	5.1	0.5	0.1	0.75	9.0
CO_2	9.3	13.3	17.1	30.0	5.6	14.0	2.8	5.6	1.6	17.9	15.8	0.06	6.0
N_2 + AR	2.3	2.5	2.1	0.2	49.3	42.5	1.8	1.1	3.1	1.4	2.15	40.82	43.0
H_2O	22.7	0.3	0.4	--	5.7	--	--	39.8	--	0.1	0.44	10.40	--
LHV, - Btu/ft^3	209	253	242	210	128	183	317	163	319	241	248	139	203
- kJ/m^3	8224	9962	9528	8274	5024	7191	12,492	6403	12,568	9,477	9,768	5,480	8000
T_{fuel}, °F/°C	570/300	700/371	250/121	200/98	1000/538	400/204	100/38	392/200	100/38	350/177	570/299	--	450
H_2/CO Ratio	.63	.80	.79	.98	.61	.33	2.36	.74	.62	1.26	.65	41.5	40
Diluent	Steam	N_2	N_2/Steam	Steam	Steam	--	Steam	Moisture	H_2O	Steam	H_2O/N_2	NA	--
Equivalent LHV													
- Btu/ft^3	150	118	113*	198	110	--	200	--	*	116	150	139	--
- kJ/m^3	5910	4649	4452	7801	4334	--	7880	--	--	4600	5910	5480	--

* Always co-fired with 50% natural gas

High Hydrogen Content Syngas for IRCC Falls in IGCC Operating Range

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Figure 5: Syngas Comparison

Maximizing the net output from a system using production gas turbines sets cost of electricity (COE) optimization parameters. GE has used technology studies to establish parameters for optimizing COE for IGCC. Established criteria indicates that the use of hydrogen alone, while technically possible, is not economically sound and that some diluent, such as nitrogen, can significantly improve economics. In air-blown systems nitrogen is already in the syngas fuel supply, while in oxygen-blown systems the waste nitrogen stream from the air separation unit (ASU) can be used as the diluent.

Currently there are almost 5,000 MW of GE IGCC type plants in operation or on order, with a cumulative total of over 200,000 operating hours. These statistics contribute to the hypothesis that this type of integrated system can be operated safely and with equipment life characteristics similar to those of natural gas combined cycle [Figure 6]. Data gleaned from this extensive IGCC operating experience can also be used in developing suitable CO_2 emission reduction cycles.

Customer	Type	MW	Syngas Start Date	Hours of Operation: Syngas	Hours of Operation: N.G.	Hours of Operation: Dist.
Cool Water	107E	120	5/84	27,000	-	1,000
PSI	7FA	262	11/95	12,300	-	3,000
Tampa	107FA	250	9/96	12,800	-	3,800
Texaco El Dorado	6B	40	9/96	11,600	17,100	-
Sierra Pacific	106FA	100	-	0	20,500	-
SUV Vresova	209E	350	12/96	42,000	1,200	-
Schwarze Pumpe	6B	40	9/96	15,500	-	3,400
Shell Pernis	2x6B	120	11/97	18,600	17,900	-
ISE / ILVA	3x109E	540	11/96	62,200	2,200	-
Fife Energy	6FA	80	-	0	5,600	-
			Total	*202,000*		

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Figure 6: GE Syngas Experience – June 1999

To date, combined cycle operating experience with IGCC plants shows good reliability, availability and maintenance (RAM) results for a wide variety of syngases [Figure 7]. Experience also indicates that a reduction in firing temperatures of high hydrogen fuels will provide gas turbine metal temperatures consistent with those of machines operating on natural gas. The effects of higher flow and high moisture content without an appropriate control system can increase metal temperatures and significantly shorten equipment life. An IGCC system operating with a low NO_X requirement and using 45% hydrogen fuel by volume may have as high as 26% moisture in the working fluid. GE's practice in IGCC applications is to reduce firing temperature, thus keeping gas turbine material temperatures and component life similar to those in natural gas applications.

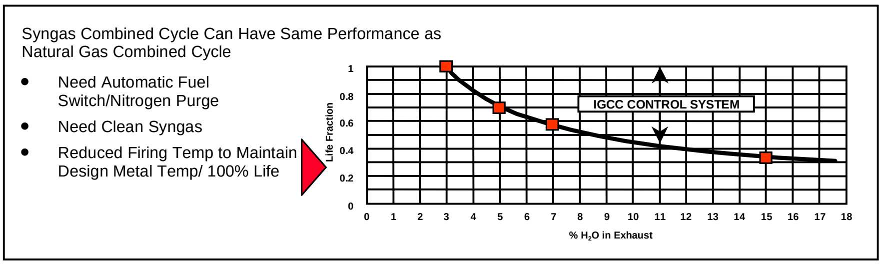

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Figure 7: Syngas – Reliability, Availability and Maintenance

The IRCC process differs from IGCC applications in that gas turbine fuel is hydrogen-only as compared to a mixed syngas. Studies have indicated a need for demonstration of hydrogen-only fuel for gas turbines. GE and Norsk Hydro have collaborated to provide the necessary demonstration.

Norsk Hydro Program

Norsk Hydro (NH) is a leading energy company headquartered in Norway and is the largest producer of hydrogen in Europe. Their studies of CO_2 emission reduction strategies with reference to COE optimization have focused on the IRCC process. GE and NH have collaborated to perform full-scale combustion system testing for a modern gas turbine with combustion exit temperatures of about 1400°C.

Combustion Test Program

The combustion test had three purposes:

1. To evaluate operability and emissions of the GE IGCC multi-nozzle combustor burning the Norsk Hydro primary design case gas. Operation testing was performed throughout the load range.
2. To evaluate component metal temperatures throughout the load range.
3. To determine sensitivity of major performance parameters (operability, emissions, steam effectiveness for NO_X control and component temperatures) to variations in hydrogen content.

Combustion system performance and operability is evaluated on the basis of measured exhaust emissions, combustion dynamics or pressure fluctuations, combustor metal temperatures, combustion system pressure drop, and flame stability and retention, particularly at low combustion exhaust temperatures and high inert gas injection rates.

Test Configuration

Testing was performed in GE's 6FA test stand because the 6FA IGCC combustion system is the basis for all current GE high temperature gas turbine IGCC combustion systems [Figure 8].

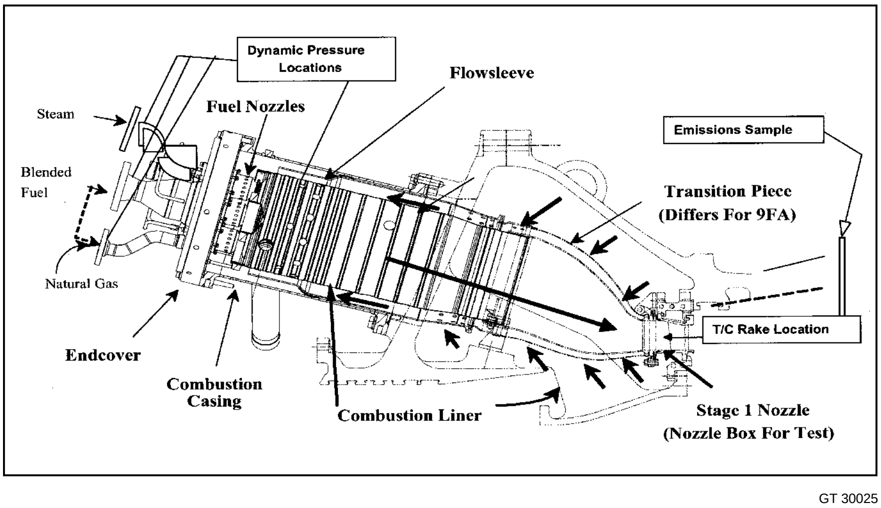

Figure 8: 6FA IGCC Multi-nozzle Combustion Systems

The 6FA test stand duplicates one combustion chamber on a gas turbine. Instead of a first stage nozzle section, the test stand is equipped with a "nozzle box," which simulates the open flow area of one nozzle segment. The nozzle box is instrumented with eight thermocouple "rakes," each containing five thermocouples located at 10, 30, 50, 70 and 90 percent radial height. In addition to the rakes, this section also contains a total pressure impact probe and emissions probes if needed. For most combustion tests, including those performed on the 6FA, emissions are taken downstream of the nozzle box in order to obtain a well-mixed sample that most closely represents actual turbine exhaust emissions.

Test Conditions

Natural gas fuel is used to fire the test stand and bring it to full airflow and firing temperature conditions for typical IGCC operation. After the inlet air temperature stabilizes, a series of test points fired on 100% natural gas are taken, followed by the addition of steam injection, to establish a baseline for combustor performance.

The transfer to hydrogen rich syngas fuel (H_2 syngas) begins with natural gas flowing through a fuel passage that is separate from the H_2 syngas passage in the fuel nozzle. While the combustor fires on natural gas, inert gas in this case, N_2 is introduced through the H_2 syngas fuel passage in order to purge the lines of any air and also to preheat the H_2 syngas lines. Next in the test sequence, steam is introduced through another separate passage. Following natural gas operation, the fuel supply is transferred from natural gas to the Norsk Hydro H_2 syngas fuel. Initiating the H_2 syngas blended fuel flow while natural gas is still flowing, but steam is turned off, prepares the transfer. After the individual components are set to the correct proportions, the controls are set to automatic and the transfer to H_2 syngas is complete.

Syngas Compositions

Table 1 shows H_2 syngas blend possible variations, depending on the configuration of the plant process. Only the major fuel constituents, H_2, N_2 and H_2O, were blended during testing, as indicated with the check marks in the last column of Table 1. The effects of the small amounts of remaining fuel constituents on flame stability and emissions were expected to be insignificant and in no way compromise the test objectives. In order to eliminate the confounding effect of CH_4 on emissions (particularly NO_X) it too was omitted from the other process gas compositions. Four nominal H_2 syngas blends were selected for testing: 46/41/13, 56/44/0, 77/23/0 and 95/5/0 ratios of $H_2/N_2/H_2O$. Note that in all cases the combustible portion of the mixture is 100% hydrogen.

Component	Component Molecular Weight	Gas C	Gas B	Gas A	Primary Design Gas	Represented in Test Syngas
H_2	2.016	53.9	76.96	94.69	45.5	✔
CO	28	0.15	0.39	0.38	1.1	
CH_4	16.04	3.07	3.28	3.64	0.4	
CO_2	44	0.1	0.1	0.1	0.6	
N_2 + AR	28	42.01	18.46	0.46	39.5	✔
H_2O	18.016	0.77	0.6	0.73	12.9	✔
Blend Mol. Wt.		13.57	7.51	2.90	14.94	
	(Btu/ft^3)	176.5	242.5	294.4	132.1	
Blend LHV	(kJ/m^3)	6952	9553	11599	5206	

Table 1: Matrix of Possible H_2 Syngas Composition Variations

A schematic of the gas blending facility, with hydrogen stored in tube trailers and blended with vaporized N_2 in controlled proportions to form H_2 syngas compositions is shown in Figure 9. For test conditions using steam, the steam is blended in the H_2 syngas line before entering the combustor fuel nozzle.

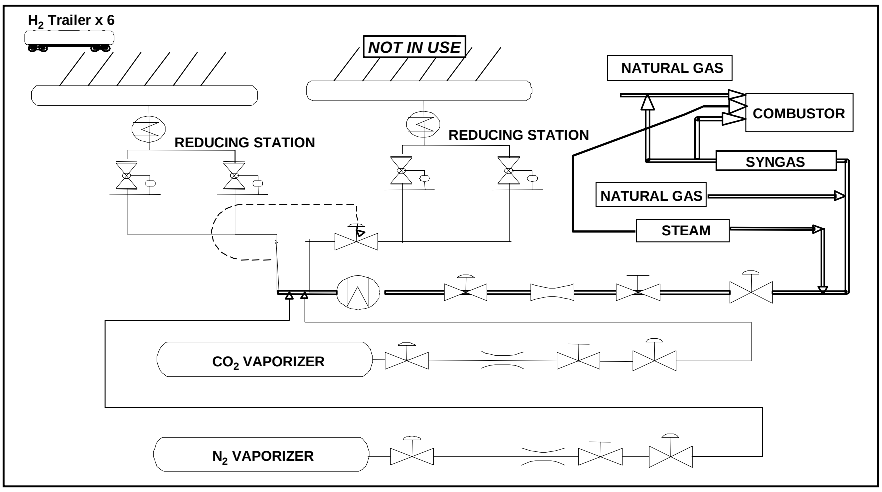

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Figure 9: Schematic of Gas Blending System

Test Results

Natural Gas Baseline

Test results showed combustor performance on natural gas to be as expected. Emissions were within acceptable tolerance when compared to previous data recorded on the same combustor configuration. Figure 10 compares emissions from this test, as a function of the ratio of head-end steam injection to fuel flow by mass, with a previous test (indicated as Test 9068 in Figure 10). Both tests show low CO emissions and the same effectiveness of steam in reducing NO_X. Unburned hydrocarbons (UHC) for both tests were below 1 ppmvd. Dynamic pressure fluctuations on natural gas were also very low.

Norsk Hydro Syngas Performance

Actual H_2 syngas compositions blended during the combustion test are shown in Table 2. H_2 syngas compositions, as measured by a spectrometer, are compared with those calculated from the individual flows. The mass spectrometer was configured to measure only dry H_2 syngas. The comparison shows a high level of agreement between the two methods of measurement.

Test points SG1, SG1S1 and SG7 through SG9 were run on the primary Norsk Hydro H_2 syngas composition. While H_2 and N_2 content at any given test point differs from the desired values indicated in Table 2, the average composition for the five test points was within 5% of the target values.

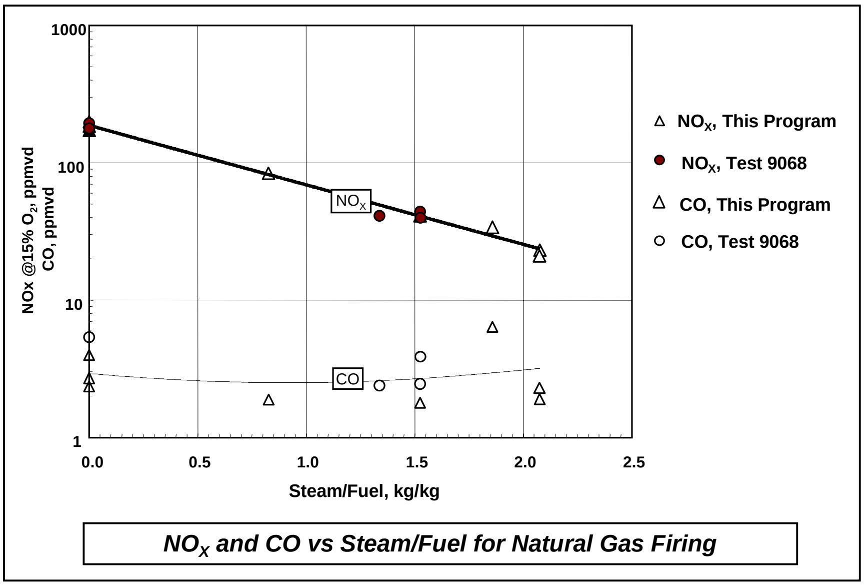

Figure 10: NO_X and CO Emissions During Natural Firing

Test Point	Mass Spectrometer		Flow Calculation			dH_2 +/- % of Ave	dN_2 +/- % of Ave
	H_2	N_2	H_2	N_2	H_2O		
SG1	-	-	53.59	33.06	13.35	N/A	N/A
SG1S1	-	-	54.70	31.99	13.31	N/A	N/A
SG2S1	-	-	58.88	41.12	0.00	N/A	N/A
SG3	73.70	26.24	76.82	23.18	0.00	2.08	6.20
SG3S1	74.30	25.73	77.35	22.65	0.00	2.01	6.36
SG4S1	88.28	11.85	89.23	10.77	0.00	0.54	4.76
SG4	85.75	14.36	87.00	13.00	0.00	0.72	4.98
SG7	46.99	52.79	50.08	49.92	0.00	3.18	2.79
SG8	45.81	53.98	50.13	49.87	0.00	4.50	3.96
SG9	41.73	58.00	43.46	56.54	0.00	2.02	1.27

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Table 2: Actual H_2 Syngas Composition Tested

Gas composition values showed significantly less variation than the variation for which the 6FA gas turbine combustor is designed and in no way invalidates the test. The remaining test points represent variations in H_2 and N_2 content for dry H_2 syngas.

Emissions:

Figure 11 shows the laboratory NO_X emissions as a function of steam-to-fuel mass ratio. The combustor exit temperature was low for the case of H_2 syngas containing 85-90% hydrogen and was in fact, falling while data were being taken, as noted in Figure 11. Therefore, the effect of steam injection on NO_X is not representative for this case, but is shown for completeness.

NO_X emissions may also be viewed in terms of equivalent calorific value, or the calculated calorific value one would obtain if the head-end steam injection were actually mixed with H_2 syngas. The results are illustrated in Figure 12. Note that the projected NO_X for 90% hydrogen is considerably greater than measured, again due to the falling combustor exit temperature.

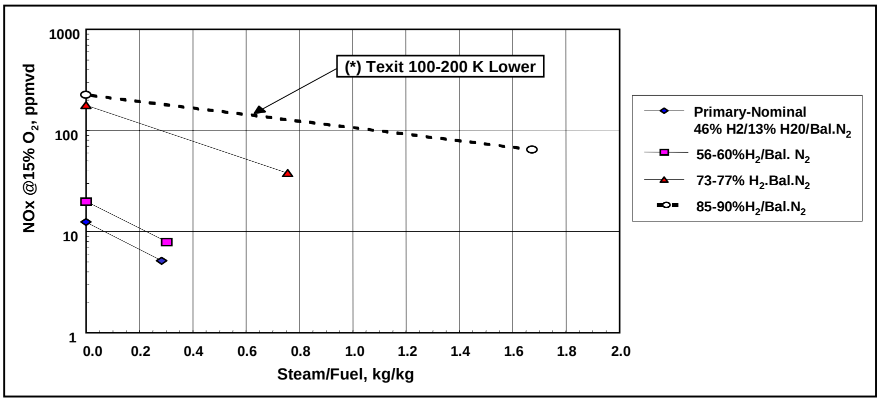

Figure 11: H_2 Syngas NO_X Emissions as a Function of Steam/Fuel Mass Ratio

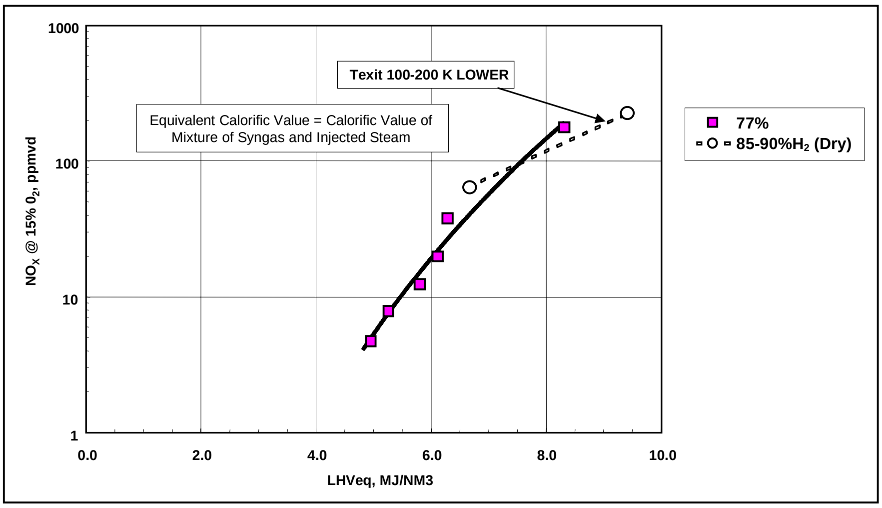

Figure 12: NO_X vs Equivalent Calorific Value for Several Fuel Compositions

Combustion Pressure Fluctuation:

Combustor test results showed very low combustion pressure fluctuation for both natural gas and H_2 syngas. The measurement is taken just inside the combustion liner in the primary reaction zone. A spectrum analyzer is used to record a dynamic pressure signal, typically at a frequency range of 0 to 800 Hz.

Figure 13 represents the overall root mean square (RMS) dynamic pressure levels as a function of steam-to-fuel ratio at full firing conditions. The data are expressed as a percentage of the maximum design amplitude. RMS levels are generally used to judge potential combustor life and stability issues. In all cases tested, the levels were less than 40% of the maximum design amplitude.

Although not shown, the maximum discrete amplitudes (pure tones at a given frequency) were less than 20% of design criteria on H_2 syngas and less than 50% during natural gas firing for all conditions tested. The maximum discrete amplitudes generally occurred at one of the combustion system's fundamental "organ pipe" frequencies, although at low levels it is often difficult to distinguish a maximum at any one frequency. In all cases, discrete levels were below the measurement threshold, or the level at which the data are considered meaningful. Higher frequency ranges were checked for at intervals throughout the test. Amplitudes in the higher frequencies were also below the measurement threshold.

The low dynamic levels measured in the combustor test were typical of the performance of GE IGCC combustion systems on H_2 syngas and consistent with GE's extensive experience base of burning low calorific fuels. Levels were well below present design criteria. As expected, the combustion noise was lower on H_2 syngas than on natural gas, but at such low levels the differential effect is small.

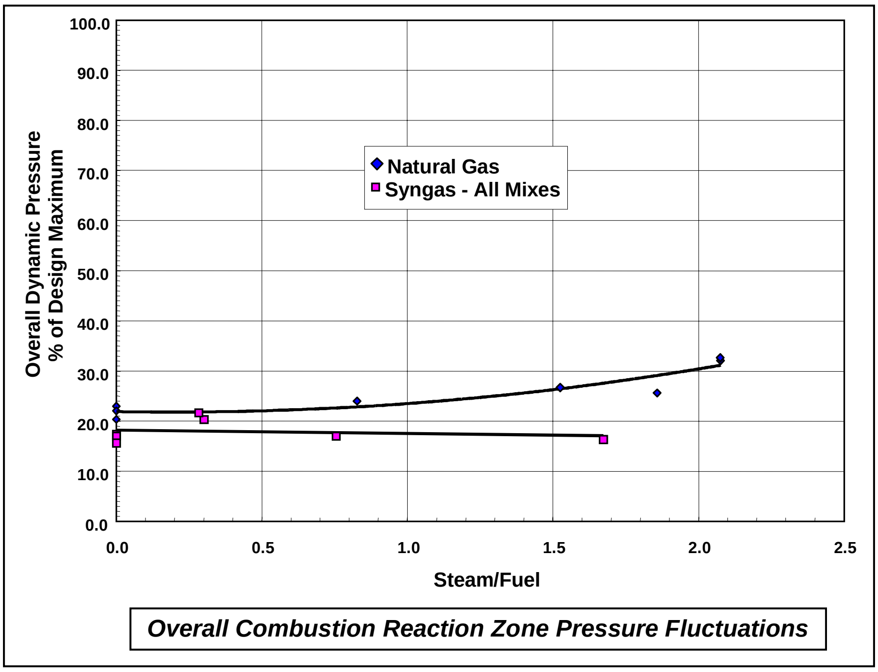

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Figure 13: Overall Dynamic as a Function of Steam (Injected) Fuel Ratio

Combustor Metal Temperatures

Metal temperatures were measured along the length of the liner at locations both in-line with a fuel nozzle tip and in between two of the six tips. In all cases the metal temperatures were well below the upper design limit of about 780°C. Figure 14 shows the variation in axial temperature distribution with fuel composition (primarily hydrogen content) for the row of thermocouples in-line with a nozzle gas tip. The temperatures in this location are typically the highest. Temperature distribution is shown as a ratio of measured temperature during full firing conditions on H_2 syngas to the design limit for the 6FA gas turbine combustor. All temperatures measured on the liner were below the design maximum and are typical of IGCC combustors in production. This was also true when steam was injected for NO_X control.

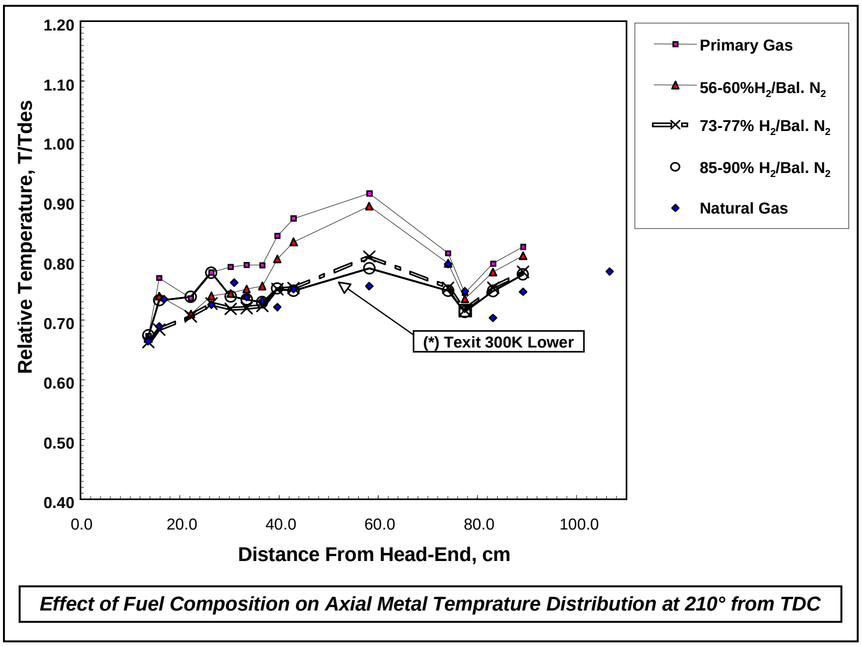

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Figure 14: Combustor Metal Temperatures at 210º from TDC – Inline with Fuel Nozzles

Increasing the total hydrogen content of the mixture resulted in decreased liner metal temperatures, even though the stoichiometric flame temperature increased substantially with increasing hydrogen. This temperature reduction may be attributed to the burner design, which produces a very tight conical recirculation zone at the exit of each nozzle tip. As the amount of hydrogen is increased, the reaction occurs more rapidly and is contained further from the liner walls. The reduction in fuel-to-air ratio with increased hydrogen also contributes to a tighter flame. Video images of the flame zone confirm the flame structure as described [Figure 15]. A considerable reduction in wall temperature at 85-90% hydrogen is attributed more to the substantial reduction in combustor exit temperature than the actual hydrogen level.

Combustion Test Summary and Conclusions

The results presented here clearly demonstrate the feasibility of burning hydrogen as the only combustible, up to 90% by volume of the total fuel in GE's IGCC combustion systems. The impacts on combustion performance and expected hardware life, if any, were minimal within the parameters tested. The limited supply of hydrogen precluded firing at 100% hydrogen with no diluent. Combustion metal temperatures were well within acceptable limits and there was no apparent evidence of flame holding on the face of the fuel nozzle gas tips.

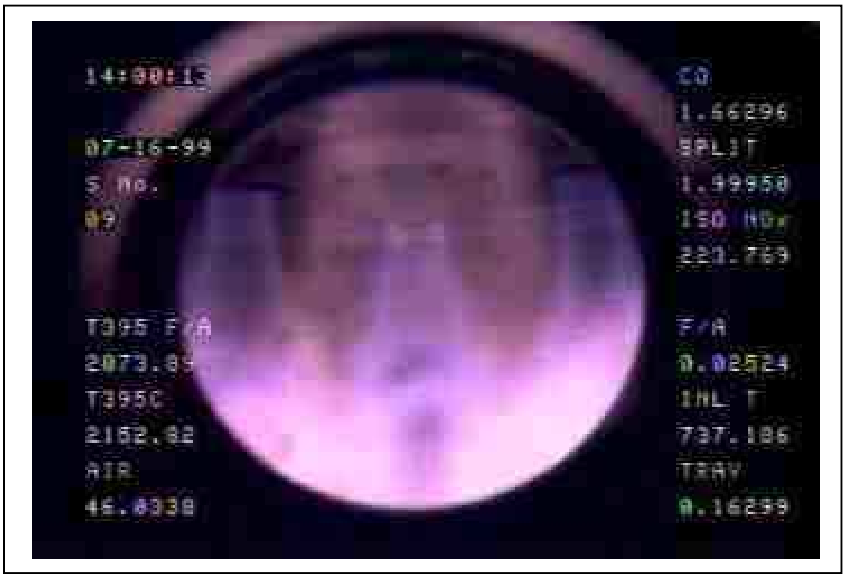

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Figure 15: Video Capture of Flame Structure, 85-90% Hydrogen

Combustion pressure fluctuation was very low on all fuels including natural gas. Head-end steam injection had very little effect on dynamics within the levels injected during testing. It is expected that higher levels of injection are possible during H_2 syngas operation without significantly affecting combustion noise.

The effect of variation in total hydrogen content on NO_X emissions was as expected, as was the amount of steam needed to suppress NO_X. The data appear to fit the previous NO_X correlation with respect to calculated flame temperature reasonably well [Figure 16]. The 7FA data used for comparison was taken from over seven separate tests with multiple combinations of H_2, CO, CO_2, H_2O, N_2 and CH_4.

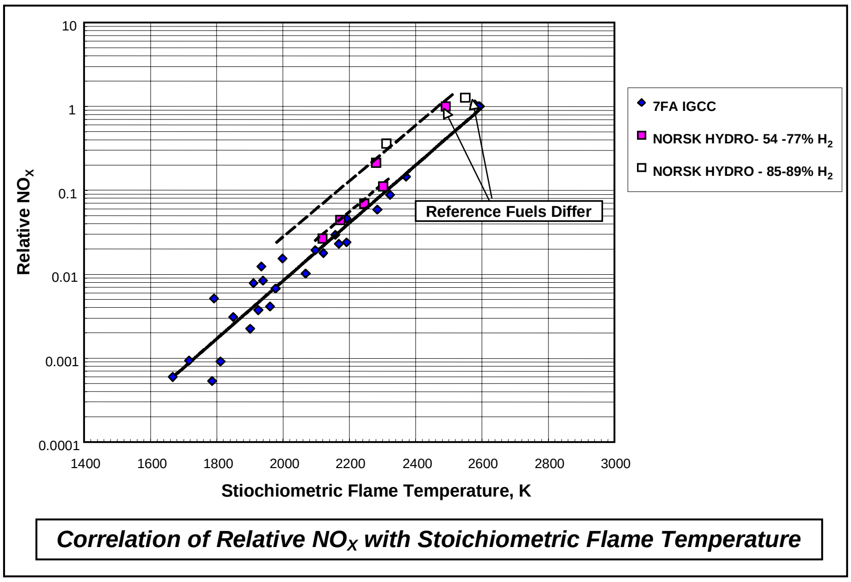

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Figure 16: Relative NO_X = NO_X/NO_X @ T Reference

While lower NO_X levels could have been achieved with higher steam injection rates, this may not be practical. Even at the moderate injection levels tested here, the exhaust moisture content is over 20% by volume. Such high levels of moisture significantly shorten turbine bucket life unless firing temperatures are substantially reduced, as discussed in the "Hydrogen Fuel for Gas Turbines" section of this paper.

H_2 syngas compositions simulated here were representative of an application where CO_2 in the gas stream was minimized. In cases where H_2 syngas contains substantial amounts of CO_2, similar NO_X levels may be achieved with considerably less steam. Figure 17 illustrates the calculated impact on NO_X emissions of CO_2 in H_2 syngas.

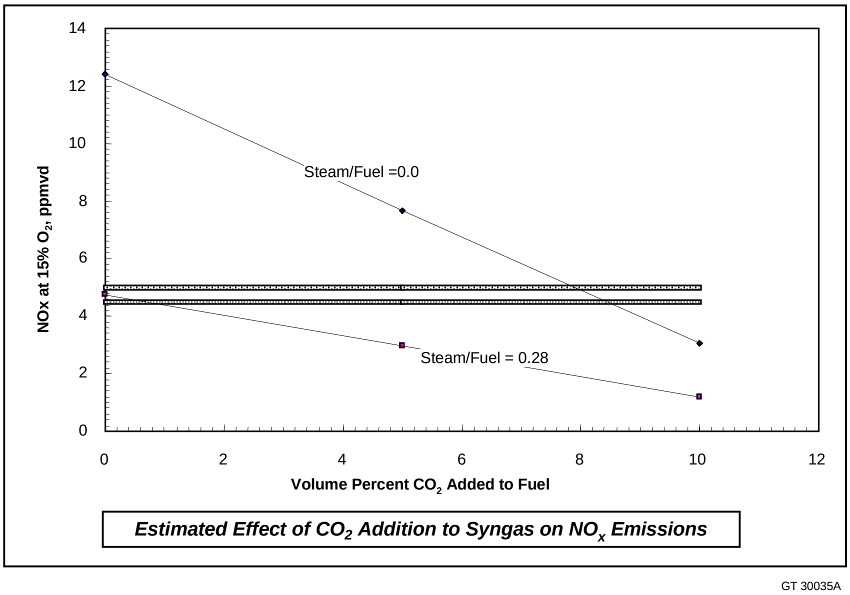

Figure 17: Primary Gas Composition

Effect of Test Results on Pre-Combustion Decarbonization – CO_2 Reduction Power Cycles

For coal and heavy oil IGCC plants where gasification costs are already included, test results show that CO_2 emission reduction can be accommodated without a large effect on COE, RAM statistics or operating parameters.

For natural gas power plants, the costs of gasification will tend to increase the COE but the effect on RAM statistics and operating parameters will be minimal. IGCC experience has shown that the integration of process and power blocks can be optimized to reduce extra costs. Normally it is expected that increased net output can be obtained during the optimization process, considerably reducing the cost of gasification.

The test results described above show that CO_2 emission reduction may be feasible with adherence to low emissions of NO_X and other pollutants but at extra cost.

Now that a combustion system technology has been developed for IRCC cycles, the next steps will be further product development by optimization and integration to reduce costs for CO_2 reduction applications.