Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project

Capture and Separation of Carbon Dioxide from Combustion Sources

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Chapter 24

AN EVALUATION OF CONVERSION OF GAS TURBINES TO HYDROGEN FUEL

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ABSTRACT

Gas turbines can play a key role in reducing CO_2 generation from fossil fuels. GE heavy-duty gas turbines are already in service in the chemical process industry on gaseous fuels containing up to 95% hydrogen by volume. Gas turbines are operating in integrated gasification combined-cycle refinery applications with the generation of hydrogen as a feedstock for hydro cracking. However, these process applications usually include other fuel constituents, which prompted the need for a study of gas turbine response when coupled to specific processes that are applied to CO_2 capture. Relative to improving the economics of CO_2 capture, the feasibility of converting existing natural gas units is an approach that needs to be examined. This study evaluated the suitability for hydrogen fuel utilization with GE's Frame 5002C and Frame 6001B gas turbines at the BP Prudhoe Bay facility. These types of machines are in wide use in industrial and chemical production applications. GE evaluated the appropriateness of seven candidate machines for utilizing high hydrogen fuels from three candidate pre-combustion de-carbonization processes. The detailed requirements definition calculations included all candidate fuels.

The three fuel choices representative of the different hydrogen generation processes that use natural gas feedstock were screened for their combustion properties and related combustion experience. All fuels evaluated were found to exhibit sufficiently acceptable combustion properties that meet the detailed requirements.

One fuel was jointly selected by GE and the BP CO_2 Capture Project team for further detailed study, with consideration of possible pre-blending fuel with steam upstream of the gas turbines for additional NO_x abatement. Comparative evaluations were also continued as well with the other fuel choices.

Relative performance changes in terms of output, heat rates and emissions at three points on the operating curve (maximum, normal operating point and minimum load) were determined at full load, minimum turndown and an intermediate load. In addition, comparative performance runs were performed at full load for all three candidate fuels, with a target NO_x level of 25 ppm.

The suitability of these machines was determined from the feasibility and cost of modifications to the flange-to-flange machine, controls, and fuel system to be able to utilize high hydrogen fuel.

This feasibility study for gas turbine retrofit requirements to burn high hydrogen de-carbonized fuel has determined that the conversion of any or all the Frame 5 and/or Frame 6 units at Prudhoe Bay is not only possible, but brings significant advantages in increased power and reduction in emissions.

INTRODUCTION

Background

The goal of the CO_2 Capture Project (CCP) is to develop low-cost technology solutions for the capture and storage of CO_2 from a range of combustion systems, in order to facilitate a reduction in atmospheric CO_2 emissions and to mitigate climate change effects of burning fossil fuels.

An important option is to convert fossil fuels such as natural gas into a hydrogen-rich fuel, which can be burned with minimal CO_2 production. Known as pre-combustion de-carbonization (PCDC), this technique is being evaluated by the CCP at the BP Central Compression Facility on the North Slope of Alaska. This facility incorporates nine GE gas turbines (GE Frame 5 and Frame 6 machines) in gas compression service.

In order to validate the feasibility of the PCDC route for CO_2 capture from gas turbines, it was necessary to determine the acceptability of the fuels arising from the technologies under development, and evaluate performance and emissions from the machines along with the costs of implementing such a scheme.

Overview
This study evaluated the suitability for hydrogen utilization of the GE Frame 5002C and 6001B gas turbines at the BP Prudhoe Bay Facility. GE evaluated the suitability of these specific machines for utilization of hydrogen fuels from three candidate PCDC processes. The suitability of these machines was determined from the feasibility and cost of modifications to the flange-to-flange machine, controls, and fuel system in order to make them capable of utilizing high hydrogen fuel. Feasibility and required modifications varied according to the PCDC process.

Relative performance changes in terms of output, heat rates and emissions at three points on the operating curve (maximum, normal operating point and minimum load) were determined for operation with the recommended modifications. A ranking and recommendation of suitability was made on the basis of criteria specific to the CCP.

STUDY METHODOLOGY

Requirements Definition
This task identified requirements and criteria for evaluating candidate gas turbines and processes and ensuring that they are consistent with the top-level requirements of both the CCP and the BP Prudhoe Bay site. GE coordinated with BP to identify and agree on the top-level requirements and/or assumptions to be used for evaluating candidate gas turbines for the CCP study. This included:

- environmental emission requirements (in terms of criteria pollutants, load requirements and characteristics, fuel and fuel conditions),
- BP hydrogen safety and operating requirements,
- available utilities,
- de-carbonization process operating characteristics,
- process streams and potential process upset conditions that must be reflected in the gas turbine hardware and controls.

Condition Assessment
GE assessed the current configuration and status for each of the candidate machines. This assessment included documentation of the base configuration, combustor type, fuels, control system type and capability, operations and maintenance history, hot gas path inspections, component modifications and uprates, and scheduled maintenance. GE consolidated and reconciled data from its own unit records for these machines against data provided by BP. This status will be documented in a summary table.

Combustion Screening
A combustion feasibility evaluation was completed for each of the proposed de-carbonized fuels (Table 1). Evaluations were specific to the candidate machines and based on the data provided from the condition assessment; combustor operating conditions were predicted from performance program evaluations. Feasibility criteria included combustion stability, turndown capability combustor life, and expected emissions at full and part load.

Performance Evaluation
Performance program evaluations were completed for prediction of expected performance changes from current natural gas firing for Frame 5002C and 6001B gas turbines using each of the candidate de-carbonized fuels provided in Table 1.

TABLE 1
CANDIDATE FUELS

	Fuel A	Fuel B	Fuel C
H_2	53.1	66.2	42.4
$H_2 + CO$	53.5	68.2	42.4
CO_2	1.6	2.4	0.0

Minimum turndown load was also estimated. Performance consists of gross output, heat rate (HHV and LHV) and expected emissions of NO_x and CO. Performance estimates were provided at full load, minimum turndown and at an intermediate load. Expected performance changes were provided for and referenced to "clean" Frame 5 and Frame 6 gas turbines fired on natural gas. Performance was computed by using control of firing temperature to maintain hot gas path part life equivalent to natural gas operation.

Conversion Options
Based on preliminary screening results, BP identified a single process fuel to be used for the basis of recommended conversion options. Each candidate gas turbine was examined in terms of suitability of retrofitting for high hydrogen fuel.

Computational Tools and Database Information
A number of modeling and analysis tools, with information from combustion test databases were utilized in the performance of this study.

Quality function deployment
A quality function deployment (QFD) was used to map customer requirements against gas turbine operational requirements. This analysis yields quantitative measures of the overall importance of individual gas turbine operational requirements for systems definitions and further systems analysis.

Combustion laboratory NO_x correlations
Combustion tests (using full-scale combustors, fuel flow rates, air flow rates and various steam injection rates) routinely measure NO_x emissions in prior combustion laboratory testing. NO_x correlations have been developed as a function of the stoichiometric flame temperature and are used to predict NO_x emissions from similar fuels.

Combustion laboratory CO correlations
Combustion tests (using full-scale combustors, fuel flow rates, air flow rates and various steam injection rates) routinely measure CO emissions in prior combustion testing. CO emissions versus turndown are used to predict CO emissions from similar fuels.

Design expert DOE software
This third-party tool produces response surfaces for gas turbine power output, heat rate and steam requirements for the candidate fuels. The "Numerical Optimization" option was used to determine the optimum fuel from the set of three candidate fuels by using response surface information for the above responses—in conjunction with measures of the level of "importance" for these responses as determined from the quality flow down tool.

RESULTS AND DISCUSSION

Requirements Definition
The top-level requirements developed between BP and GE for both the CCP and the BP Prudhoe Bay site were integrated with requirements for the Frame 5 and Frame 6 gas turbines at Prudhoe Bay in a GE Six Sigma QFD flow down tool. This method yields a graded list of important parameters for determining the optimum gas turbine syngas for use by the Prudhoe Bay gas turbines. This resulted in the selection

of a specific fuel choice—Fuel A—to concentrate the detailed study upon, with consideration of possible pre-blending fuel with steam upstream of the gas turbines for additional NO_x abatement. Comparative evaluations were continued as well with the other possible fuel choices. After consultation with BP and CCP members, and consideration of GE gas turbine requirements with GE project team members, an initial requirements definition was determined as outlined in Table 2.

TABLE 2
TOP LEVEL REQUIREMENTS

Requirement	Definition	Comments
(1) Gas turbine heat rate	Minimize heat rate	Although the natural gas input to the decarbonization process is relatively inexpensive, the process is costly. Fuels A and C have the lowest heat rate, with Fuel C marginally better than Fuel A
(2) Gas turbine output	Maximize output	Fuels A and C have the highest output, with Fuel C marginally better than Fuel A
(3) Gas turbine exhaust NO_x level	25 ppm target	The NO_x target is a primary driver for heat rate, power output and cost in determining the "desirability" of a fuel
(4) Gas turbine upset	Return to natural gas operation	The high-hydrogen fuel plant has a projected availability of 98 + %. If an upset occurs, there would be a controlled transfer to natural gas operation

As part of this requirements definition, performance estimates for both the MS5002C and MS6001B gas turbines were required at ambient temperatures of − 40, 32, and 86 °F for full load, minimum turndown and an intermediate load condition. Values of gross output, LHV heat rate, HHV heat rate, and exhaust NO_x emissions were determined for these conditions. In addition, a summary table of comparative values for these parameters at full load was to be provided for Fuels A, B and C as initially supplied by BP.

Extensive experience with handling hydrogen-rich streams has been accumulated in refineries and industrial air separation. By recognizing special considerations in the gas turbine scope (such as wide flammability range, potential for detonation, and low-ignition energy), hydrogen/high-hydrogen fuels can be safely handled for this application. Hydrogen plants can achieve a high availability of over 98%. Source natural gas used by the de-carbonization process can be assumed to be available during any upset conditions of the hydrogen generation process, so that overall availability of the gas turbine will be high and typical of the availabilities expected from natural gas units.

In order to further connect customer requirements to the fuel selection process, an overview mapping of customer system requirements to gas turbine requirements was performed with an internal GE Six Sigma QFD flow down tool. Results determined from the QFD are given in Figure 1. This Pareto is the chart output of the relative importance of each system requirement. In addition to the essential requirements of reliability and availability, these results indicate that gas turbine heat rate, exhaust NO_x level (Syngas NO_x) and output are important factors to be utilized in choosing the optimum syngas for the Prudhoe Bay gas turbines.

Condition Assessment

The seven gas turbines considered for this study that are currently in operation at BP Prudhoe were manufactured by GE Energy at our Greenville, South Carolina, Schenectady, New York, or Florence, Italy

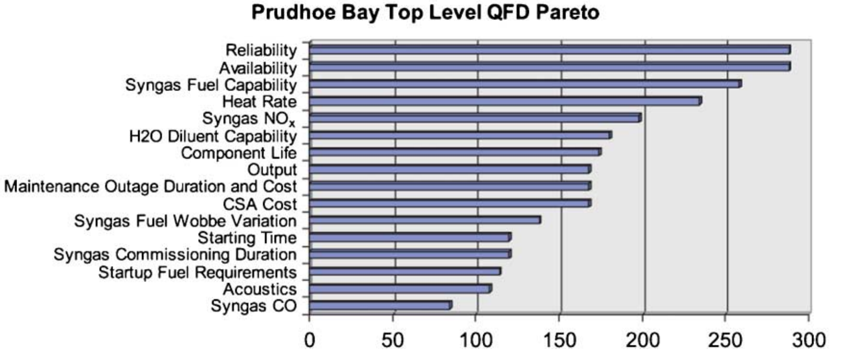

Figure 1: Results of analysis of system requirements.

locations. The MS5002C and MS6001B gas turbines researched in this study currently operate on natural gas. The resulting information is based on GE internal documents and applications solely owned and updated by the General Electric Company. Conditions, uprates and modifications were determined for the MS6001B units shipped in 1992, the MS5002C units shipped in 1985, and the MS5002C units shipped in 1998.

Combustion Screening

The three fuel choices denoted as fuel A, B and C were submitted to a preliminary screening for their combustion properties and related combustion experience. This task was conducted on an iterative basis to allow parameter space to be selectively narrowed before detailed performance calculations were initiated. All fuels listed in Table 1 exhibit sufficiently acceptable combustion properties that the detailed requirements definition calculations included for all candidate fuels. All final candidates—Fuel A with 10% blended steam (for NO_x control); and Fuel C—may be utilized with the same combustion hardware. Fuel nozzles exist for the 6B that may be readily modified for this application, whereas fuel nozzles for the MS5002C will require development work.

The GE integrated gasification combined-cycle (IGCC) group has utilized fuels with H_2 contents between 8 and 62%. Fuels having hydrogen up to 95% have been used in GE gas turbines in process plants. Hence, all candidate fuels are well within the envelope of operating experience. All candidate fuels also satisfy the requirements that the heat content of the fuel be greater than 110 BTU/scf, and the flammability ratio be greater than 2.2. The flammability of H_2 tends to be too high for light-off and in all cases, light-off with natural gas will be required. All fuels listed in Table 1 exhibit sufficiently acceptable combustion properties.

The projected NO_x is a specific function of the flame temperature, which in turn is a function of the fuel species. Fuel "A" may expect 45 ppm unabated, whereas that is reduced to 24 ppm and 15 ppm with steam/fuel of 0.1 and 0.2, respectively. Fuel "B" will yield 79 ppm unabated and requires steam/fuel of 0.5–0.6 to achieve 22–18 ppm, respectively. Fuel "C" yields 7 ppm unabated.

The requirements definition task further narrowed the candidate fuels to:

- Fuel A unabated (no steam for NO_x control).
- Fuel A with 0.1 steam/fuel (by weight) injected into the combustor for NO_x control.
- Fuel A with 0.1 steam/fuel (by weight) blended into the fuel for NO_x control.
- Fuel C unabated (no steam for NO_x control).

From a combustion perspective, all four "fuels" are not only viable, but may all be utilized with the same combustion hardware. The key parameter in this comparison is the Wobbe index. A large Wobbe index reflects a fuel with a high-energy density. Fuel passages must be increased for lower Wobbe indices to allow the larger volumes of fuel required to deliver the same BTU flow. Once nozzle orifice sizes are chosen, the Wobbe index may vary +/− 10% about its design point. To this end, the nozzles may be sized for Fuel A with 10% blended steam (Wobbe = 6.3) and also accept Fuel A (Wobbe = 6.86) and Fuel C (Wobbe = 5.7).

The last issue to address in a preliminary combustion screening is turndown. The flammability of the fuel from full-speed no-load (FSNL) to base load is not in question. However, CO compliance at the reduced firing temperature is a major concern. Firing temperature versus load, using Fuel A in a Frame 5 or Frame 6 gas turbine at minimum ambient temperature (−40 and −75 °F, respectively) is illustrated in Figure 2.

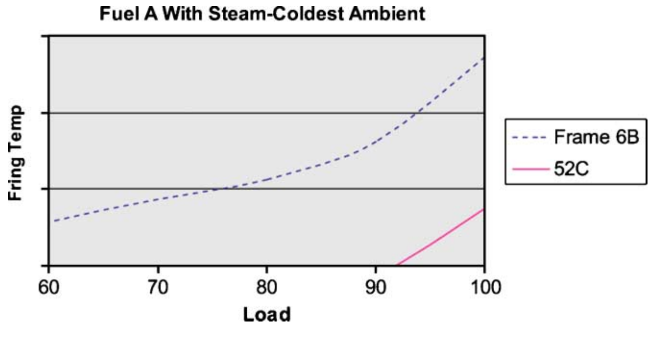

Figure 2: Firing temperature versus load for Frame 5 and Frame 6 gas turbines at lowest ambient.

Typical IGCC fuels possess a H_2/carbon ratio of order unity. With these fuels, turndown to firing temperatures of order 1500–1600 °F are tolerable before CO emissions increase above compliance levels. While we do not have gas turbine data for fuels with a H_2/carbon ratio typical of Fuel A, it is apparent that turndown to firing temperatures well below 1500 °F will most likely sustain CO compliance. For lack of hard data, a 1500 °F limit on firing temperature will be used to restrict the CO compliance estimate to 50% to base load on a Frame 6B, and 90% to base load on a Frame 5 gas turbine. For reference, CO compliance on natural gas in ISO conditions (59 °F) is usually restricted to 60% to base load on a Frame 6B and base load only on a Frame 5 gas turbine.

Performance evaluation

Results of the QFD Pareto from the requirements definition task were coupled with performance runs for all three candidate fuels in order to determine the optimum fuel for further detailed study. Using the chosen Fuel A, performance runs were completed for prediction of expected performance changes from current natural gas firing of selected Frame 5 and 6 gas turbines located at the Prudhoe Bay site. These performance runs with Fuel A yielded results for gross output, heat rate (HHV and LHV), and expected emissions of NO_x at full load, minimum turndown and an intermediate load conditions. In addition, summary comparative performance was determined at full load for all three candidate fuels, for a target NO_x level of 25 ppm.

Preliminary performance runs were made for the three syngases (Fuels A, B and C) over the specified ambient temperature range. Response surfaces of results of these runs were made for gas turbine heat rate, NO_x level and output. These response surfaces were coupled with the "importance" results of the QFD Pareto developed in the requirements definition task in order to yield an "Overall Desirability" for a given syngas as a function of ambient temperature, for a given target NO_x level. Results of these analyses are given in Figure 3. [Note: Fuel A is Fuel 1.0, Syngas B is Fuel 2.0 and Syngas C is Fuel 3.0 in this figure.]

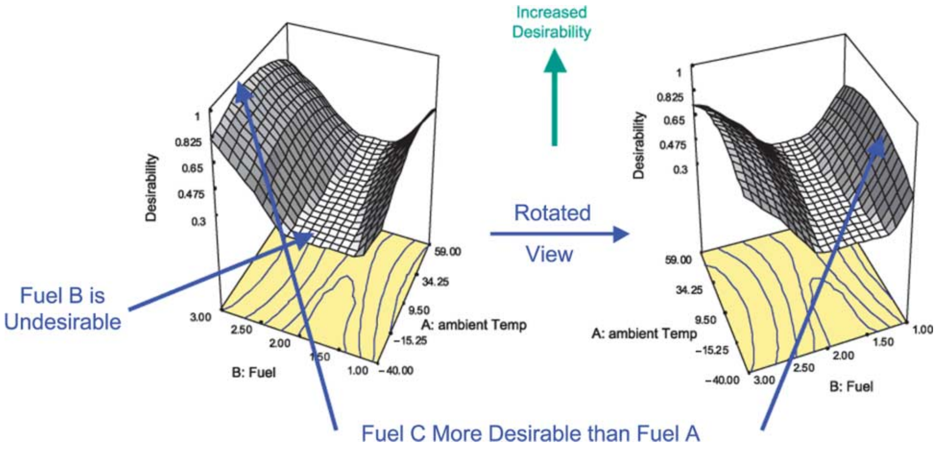

Figure 3: Results of syngas analysis for a 25 ppm target NO_x level.

This analysis suggests that Syngas C is the most desirable, with Syngas A at a slightly lower level of desirability. Syngas B was indicated to be undesirable for this analysis.

The following results were obtained for acceptable candidate syngases:

- Fuel A unabated (with no steam for NO_x control).
- Fuel A with 0.1 steam/fuel (by weight) injected into combustor for NO_x control.
- Fuel A with 0.1 steam/fuel (by weight) blended with the fuel.
- Fuel C unabated (with no steam for NO_x control).

After input from BP to pursue Syngas A over Syngas C, a decision was mutually made to only pursue Fuel A as the candidate Syngas for the performance runs in Task 4. It was agreed that Summary Performance data (gas turbine output, heat rate and steam rate) would be provided for a target gas turbine exhaust NO_x level of 25 ppm for Fuels A, B and C for ambient temperatures of −40, 32, and 86 °F.

Subsequent to this choice of Fuel A for performance evaluations, additional performance runs were completed across the ambient temperature range using Fuel A, with abatement to an NO_x level of 25 ppm with steam injection. Firing temperatures were controlled on a schedule that targeted maintenance of maximum possible hot gas path part life. All performance runs were computed referenced to “clean” Frame 5 and Frame 6 gas turbines, with appropriate margins.

Utilizing results for the run for the ambient temperature that required the highest steam/fuel ratio necessary for NO_x abatement to the 25 ppm level, a blended fuel (steam + Fuel A) was set-up for subsequent performance runs. All of the final Fuel A results were calculated based on performance runs using this Blended Fuel A. Results for incremental performance (results for “Blended Fuel A” versus “Original Normal Natural Gas”) for 6B gas turbines are given in Table 3.

Since the combustion screening task indicated that a maximum turndown of 60% is appropriate for the Blended Fuel A, the maximum turndown results above are calculated for 60% load, and the intermediate load was set at 80% of full load. The above results indicate significant increases in gross output for all but the minimum ambient temperatures, and for all load conditions, and decreases in heat rates (increased efficiencies) for all conditions. NO_x levels for all cases are at, or below, the target level of 25 ppm.

Results for incremental performance (for Blended Fuel A versus Original Normal Natural Gas) for 5-2C gas turbines are given in Table 4.

TABLE 3
INCREMENTAL PERFORMANCE FOR FRAME 6B GAS TURBINES (BLENDED FUEL A VERSUS ORIGINAL NATURAL GAS; 6B DIFFERENTIAL PERFORMANCE ON SYNGAS A BLEND)

Item	**Ambient temperature (°F)**		
	−40	**32**	**86**
Base load			
Gross output change (%)	1.28	15.74	27.61
LHV heat rate change (%)	−11.32	−13.75	−15.23
HHV heat rate change (%)	−5.45	−8.14	−9.65
Expected exhaust NO_x (ppm)	23	25	22
Intermediate load			
Gross output change (%)	3.87	15.74	27.60
LHV heat rate change (%)	−14.30	−13.94	−16.27
HHV heat rate change (%)	−8.64	−8.24	−10.80
Expected exhaust NO_x (ppm)	19	22	20
Minimum turndown			
Gross output change (%)	1.29	18.70	27.58
LHV Heat rate change (%)	−9.87	−16.82	−17.77
HHV heat rate change (%)	−3.96	−11.38	−12.34
Expected exhaust NO_x (ppm)	17	18	17

TABLE 4
INCREMENTAL PERFORMANCE FOR FRAME 5-2C GAS TURBINES (BLENDED FUEL A VERSUS ORIGINAL NATURAL GAS; 5-2C DIFFERENTIAL PERFORMANCE ON SYNGAS A BLEND)

Item	**Ambient temperature (°F)**		
	−40	**32**	**86**
Base load			
Gross output change (%)	3.38	17.31	20.23
LHV heat rate change (%)	−12.15	−12.66	−15.81
HHV heat rate change (%)	−6.36	−6.93	−10.31
Expected exhaust NO_x (ppm)	17	23	18
Intermediate load			
Gross output change (%)	0.55	17.37	20.23
LHV heat rate change (%)	−10.66	−13.69	−14.85
HHV heat rate change (%)	−4.78	−8.02	−9.26
Expected exhaust NO_x (ppm)	14	18	14
Minimum turndown			
Gross output change (%)	0.55	17.35	20.24
LHV Heat rate change (%)	−12.52	−14.65	−15.68
HHV heat rate change (%)	−6.81	−9.02	−10.17
Expected exhaust NO_x (ppm)	11	14	11

Combustion screening indicates that a maximum turndown for the Frame 5 gas turbine is less than the Frame 6, since the lower firing temperatures of Frame 5 results in reaching CO emission levels at a lower turndown load. Therefore, a maximum turndown of 90% is appropriate for the Blended Fuel A. As a result of this choice of maximum turndown level, the maximum turndown results above are calculated for 80% load, and the intermediate load was set at 90% of full load. The above results indicate significant increases in gross output for all ambient temperatures and load conditions, and decreases in heat rates (increased efficiencies) for all conditions. NO_x levels for all cases are at, or below, the target level of 25 ppm.

Even though detailed performance runs and combustion analysis focused on Fuel A, performance results are presented for all three candidate fuels for reference. Runs for Fuels A and B were performed with steam injection for NO_x abatement to a 25 ppm level. Performance runs with Fuel C did not use steam for NO_x control, since the unabated NO_x was at the approximate 6 ppm level for all ambient temperatures. Summary incremental performance (results for Fuel A, Fuel B and Fuel C versus Original Normal Natural Gas) for frame 6B gas turbines are given in Table 5.

TABLE 5
INCREMENTAL PERFORMANCE FOR FRAME 6B GAS TURBINES (FUEL A, FUEL B, FUEL C VERSUS ORIGINAL NATURAL GAS; 6B SUMMARY DIFFERENTIAL PERFORMANCE ON SYNGASES A, B AND C)

Item	**Ambient temperature (°F)**		
	−40	**32**	**86**
Base load—Fuel A			
Gross output change (%)	−2.43	11.33	22.92
LHV heat rate change (%)	−9.47	−13.43	−14.85
HHV heat rate change (%)	−3.51	−7.76	−9.22
Expected exhaust NO_x (ppm)	23	25	22
Base load—Fuel B			
Gross output change (%)	0.06	12.99	14.14
LHV heat rate change (%)	−5.30	−8.77	−8.77
HHV heat rate change (%)	0.51	−3.12	−3.07
Expected exhaust NO_x (ppm)	25	25	25
Based load—Fuel C			
Gross output change (%)	−1.77	14.13	22.32
LHV Heat rate change (%)	−9.28	−11.38	−12.97
HHV heat rate change (%)	−3.08	−5.31	−7.03
Expected exhaust NO_x (ppm)	<10	<10	<10

As indicated in the Requirements Definition analyses, gross output increases and heat rate decreases (increased efficiencies) for fuels A and C are more favorable than Fuel B results. In all of the above cases, abatement of NO_x from 80 ppm to 130 ppm for the high-hydrogen Fuels A, B and C relative to results for the present natural gas operation is evident. Summary incremental performance (results for Fuel A, Fuel B and Fuel C versus Original Normal Natural Gas) for 5-2C gas turbines are given in Table 6.

As indicated in Task 1 analyses, gross output increases and heat rate decreases (increased efficiencies) for Fuels A and C are more favorable than Fuel B results. In addition, Task 1 indications that Fuel C was slightly more attractive than Fuel A are verified by the above results. In all of the above cases, abatement of NO_x by 50–80 ppm for the high-hydrogen Fuels A, B and C relative to results for the present natural gas operation is evident.

TABLE 6
INCREMENTAL PERFORMANCE FOR FRAME 5-2C GAS TURBINES (FUEL A, FUEL B, FUEL C VERSUS ORIGINAL NATURAL GAS; 5-2C SUMMARY DIFFERENTIAL PERFORMANCE ON SYNGASES A, B AND C)

Item	**Ambient temperature (°F)**		
	−40	**32**	**86**
Base load—Fuel A			
Gross output change (%)	3.38	17.31	20.23
LHV heat rate change (%)	−12.15	−12.66	−14.02
HHV heat rate change (%)	−6.36	−6.93	−8.26
Expected exhaust NO_x (ppm)	17	23	18
Base load—Fuel B			
Gross output change (%)	2.70	13.52	14.18
LHV heat rate change (%)	−5.63	−8.61	−9.29
HHV heat rate change (%)	0.24	−2.96	−3.54
Expected exhaust NO_x (ppm)	25	25	25
Base load—Fuel C			
Gross output change (%)	5.04	25.32	35.98
LHV Heat rate change (%)	−15.63	−18.17	−20.70
HHV heat rate change (%)	−9.86	−12.61	−15.19
Expected exhaust NO_x (ppm)	<10	<10	<10

CONCLUSIONS

The following conclusions were reached during this assessment study for the possible conversion of the GE Frame 5 and Frame 6 gas turbines at the BP Prudhoe Bay facility to burn de-carbonized (high hydrogen) fuel:

1. Requirements and criteria for evaluation of candidate gas turbines have been identified that are consistent with the top-level requirements of both the CCP and the BP Prudhoe Bay site. These requirements and assumptions include emission requirements, load requirements and characteristics, fuel and fuel conditions, BP hydrogen and safety requirements, as well as high-hydrogen fuel variability and upset characteristics.
2. Based on the overall condition assessment of the candidate Frame 5 and Frame 6 units, conversion for adding hydrogen to the current fuel is acceptable. The MS5002C and MS6001B gas turbines currently have the combustor hardware and hot gas path components to implement the desired modification.
3. Several modifications will be needed to implement the addition of hydrogen to the current operational fuel.
4. The three fuel choices denoted as Fuels A, B and C were screened on a preliminary basis for their combustion properties and related combustion experience. All fuels evaluated exhibit satisfactory combustion properties.
5. Fuel C is found to be the most desirable, with Fuel A at a slightly lower level of desirability. Syngas B was indicated to be undesirable for this study.
6. Analyses of the performance of both Frame 5 and Frame 6 gas turbines fired with Fuels A, B and C, coupled with BP operational requirements, indicate that both Fuels A and C are attractive high-hydrogen fuels for use in these machines. Further consideration of gas turbine performance, and BP process plant capabilities, indicates that Fuel A is the most desirable fuel for the Prudhoe Bay Re-powering Project from a gas turbine perspective.

7. Assessments of these fuel choices relative to the desired emission requirements resulted in the following:
   (a) 45 ppm NO_x expected with Fuel A unabated.
   (b) 25 ppm NO_x expected with Fuel A blended with 10% steam.
   (c) Single digit NO_x expected with Fuel C unabated.
   (d) CO emissions of the MS5002C will be in compliance from 90% load to base load.
   (e) CO emissions of the MS6001B will be in compliance from 60% load to base load.
8. Fuel “A”, Fuel “A with 10% blended steam” and Fuel “C” may all be utilized with the same combustion hardware.
9. Performance runs using a Blended Fuel A (Fuel A + Steam necessary for NO_x abatement to a maximum 25 ppm) indicate that gross output over the ambient temperature range (except for the minimum ambient temperature) for both the Frame 5 and Frame 6 gas turbines is significantly above that when the machines are run on the normal natural gas available at Prudhoe Bay. In addition, heat rates for the blended fuel are significantly below (i.e. higher efficiency) that for Frame 5 and Frame 6 units fired with the normal natural gas.

NOMENCLATURE

5-2C	GE MS5002C gas turbine
6B	GE MS6001B gas turbine
CCP	CO_2 Capture Project
Frame 5	GE MS5002C gas turbine
Frame 6	GE MS6001B gas turbine
FSNL	Full-speed, no-load
HHV	Higher heating value
IGCC	Integrated gasification combined cycle
LHV	Lower heating value
MS	Model series
PCDC	Pre-combustion de-carbonization
ppm	Parts-per-million
QFD	Quality Function Deployment