1.2.2

Implications of CO_2 Sequestration for Gas Turbines

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1.2.2-1 Introduction

A variety of industrial processes such as power plants, oil refineries, cement works, and iron and steel production emit large amounts of CO_2. Approximately a third of all the CO_2 emissions due to human activity, however, come from fossil fuel-based power plants, with each power plant capable of emitting several million tonnes of CO_2 annually. These emissions could be reduced substantially by capturing and storing the CO_2 while other sources of emissions, such as transport and domestic buildings, cannot be tackled in the same way because of the large number of small sources of CO_2.

The capture of CO_2 in an IGCC power plant consists of gasifying the feedstock in an O_2 blown gasifier system and shifting the CO to H_2 by catalytic reaction with steam[1]:

$$CO + H_2O = CO_2 + H_2. \qquad (1)$$

The CO_2 is then removed for sequestration from the syngas to produce a "decarbonized" fuel gas for combustion in a gas turbine. There are primarily two schemes for these processing steps consisting of shifting, CO_2 removal and desulfurization of the syngas for current or near term technology plants, i.e., plants incorporating cold gas cleanup:

- Employ sour shifting of the syngas followed by desulfurization and CO_2 recovery within the same acid gas removal unit; or,
- Desulfurize the syngas first followed by shifting and then removal /recovery of the CO_2.

The choice of either scheme depends primarily on the gasification heat recovery system employed (i.e., the extent to which cooling of the raw gasifier effluent is accomplished in a syngas cooler before the syngas is quenched / scrubbed with water to remove particulate matter).

1.2.2-2 Implications for Gas Turbines

Syngas Composition and Thermal Diluents

Table 1 shows the composition of a decarbonized syngas (shifted and then 90% of the CO_2 removed) as well as an "un-decarbonized" syngas leaving the acid gas removal unit of a high-temperature slurry-fed entrained-bed gasifier fed with a bituminous coal[2]. The H_2 content of both the syngas streams is considered high enough to preclude the use of current design pre-mixed gas turbine combustors to limit the formation of NOx. Diluent addition is required to the syngas in order to reduce the NOx generation when utilizing "diffusion" type combustors, the amount of diluent addition required by decarbonized syngas, however, being higher than that required for the un-decarbonized syngas. Two types of diluents are available in an IGCC plant, water vapor introduced into the syngas stream by direct contact of the syngas with hot water in a counter-current column while recovering low temperature waste heat and / or N_2 supplied by an elevated pressure air separation unit. The choice of the diluent depends on a number of factors such as

- amount of low temperature waste heat available for the humidification operation, and
- amount of excess N_2 available from the air separation unit.

Table 1 Typical Clean Syngas Compositions (Dry and Sulfur Free Basis)

Component	Non-decarbonized	Decarbonized
CO	50.1	2.8
H_2	37.4	94.1
CO_2	10.2	0.6
CH_4	0.1	0.1
$Ar + N_2$	2.2	2.4
Total	100.0	100.0

The amount of low temperature waste heat available in a gasification plant in turn depends primarily on the gasification heat recovery system employed (i.e., the extent to which cooling of the raw gasifier effluent is accomplished in a syngas cooler before the syngas is quenched / scrubbed with water). On the other hand, the amount of N_2 available as a diluent for the gas turbine depends on

- the specific O_2 consumption of the gasifier - the amount of N_2 produced by the air separation unit is lower when the specific O_2 consumption of the gasifier is lower; and,
- the type of gasifier feed system - dry feed systems utilize significant portions of the N_2 as lock hopper pressurization gas as well as in the drying and transport of the coal into the gasifier and only the remaining amount of N_2 is available for gas turbine injection.

A combination of the two diluents, i.e. water vapor and N_2, may also be utilized, the relative amounts depending on the overall plant integration scheme and the trade-offs between efficiency and capital cost. In such cases, an option available consists of introducing the moisture into the N_2 stream instead of the syngas. When N_2 or moisturized N_2 is utilized as a diluent, it may be either premixed with the decarbonized syngas before supplying it to the combustor of the gas turbine or it may be introduced into the combustor through a separate injector. Premixing the diluents with the syngas versus keeping them separately upstream of the combustor will have implications on the effectiveness of the diluent in lowering the local combustion temperature; a diluent entering the combustor premixed with the syngas would be more effective in lowering the NOx than if it entered the combustor through a separate nozzle. On the other hand, some savings in the N_2 compressor horsepower may be realized in the case where the diluent is introduced into the combustor separately if the pressure drop associated with the fuel control valve is much higher than that for the diluent.

It should be noted that the specific heat of the triatomic H_2O molecule is significantly higher than that of the diatomic N_2 molecule on a mole basis and thus the relative amounts of diluents required, i.e. water vapor versus N_2 on a volumetric or mole basis by a given amount of syngas are quite different.

Thus, in summary, the composition of the syngas / diluent are dependent on the type of gasifier, heat recovery and energy integration options and the type of air separation unit, i.e., whether it is an elevated pressure air separation unit which can supply high pressure N_2 for use as a thermal diluent for NOx control.

Gas Turbine Pressure Ratio

The pressure ratio of the gas turbine increases when firing syngas, which is a much lower heat content gas than natural gas. The increase in pressure ratio is dependent upon the amount and nature of the diluent added and the degree to which the compressor inlet guide vanes are closed. The surge margin available in the compressor could thus constrain the amount of diluent that may be added and the resulting NOx emissions, in addition to the constraints set by the combustor design with respect to achieving stable combustion while limiting the CO emissions. Air extraction from the compressor may be required in order to limit the increase in the engine pressure ratio, in which case the extracted air (after cooldown / heat recovery) may be used efficiently in an elevated pressure air separation unit.

Gas Turbine Firing Temperature

The H_2O vapor content of the working fluid flowing through the turbine, especially in the case when decarbonized syngas is the fuel and while utilizing water vapor as the diluent, is significantly higher than that in the case when natural gas is the fuel (i.e., compared to the case when natural gas is fired in dry low NOx combustors). The following implications exist for the gas turbine in such applications:

- Derating of the turbine firing temperature due the different aero-heat transfer characteristics[3] and
- Life of the thermal barrier coatings, and any ceramics that may be utilized in advanced gas turbines in the future.

Additionally, a gas turbine designed for a certain firing temperature on natural gas would see derating of the firing temperature not only due to the increased concentration of H_2O vapor in the working fluid but also due to the increase in the pressure ratio since the temperature of the cooling air increases as the pressure ratio is increased. In the case of a steam-cooled gas turbine, however, derating of the firing temperature due to the increase in pressure ratio may be less significant (since the cooling steam temperature may be maintained independently of the gas turbine pressure ratio), unless the low pressure air-cooled stages of the gas turbine become the bottleneck.

Thus, the choice of the diluent to be utilized, i.e., H_2O vapor versus N_2 or their relative amounts should be included in the trade-off / optimization studies, i.e., take into account not only the gasification island heat recovery options but also the accompanying extent of the gas turbine firing temperature reduction.

Bottoming Steam Cycle

The effect of lowering the firing temperature while increasing the pressure ratio significantly reduces the gas turbine exhaust temperature which has implications on the steam bottoming cycle. With lower steam superheat and reheat temperatures as compared to those corresponding to a natural gas fired combined cycle, the optimum steam cycle pressures would tend to be lower than those for the steam cycle in a natural gas fired combined cycle.

Use of Selective Catalytic Reduction (SCR)

At the present time, gas turbine manufacturers are willing to guarantee 15 ppmV NO_x (dry, 15% O_2 basis) for gas turbines in IGCC applications with the requirement of the thermal diluent addition. More stringent NOx emission requirements [e.g., 3 ppmV NO_x (dry, 15% O_2 basis)] in the future may require the installation of an SCR for post combustion control of the NO_x or advanced gas turbine combustors that generate less NO_x such as the trapped vortex combustor[4].

Development of low NO_x combustors has a number of technical challenges to overcome due to the presence of a large concentration of H_2 in the syngas (auto-ignition and flash-back being the challenges with pre-mixed combustor designs). These technical challenges will be even more severe for the more advanced gas turbines which will have higher pressure ratios (to take full advantage of the higher firing temperatures) and thus higher combustion air temperatures than current gas turbines in syngas applications. Decarbonized syngas will make it more challenging since the H_2 content of the decarbonized syngas is significantly increased.

Although SCRs have been utilized in coal fired boiler plants, the application of SCRs in IGCC plants poses special challenges. The NH_3 slip from the SCR is known to react with the SO_3 formed during the combustion process as well as some formed in the SCR itself (depending on the vanadium content of the catalyst) to form salts (ammonium bisulfate, sulfate and bisulfite) as the gases are cooled during heat recovery. Ammonium bisulfate tends to be especially sticky and can deposit on the cooler surfaces of heat transfer equipment causing fouling as well as corrosion. Any unreacted NH_3 that may be emitted to the atmosphere is by itself a pollutant. In the case of a boiler, these problems are less severe since the NH_3 slip from the SCR is preferentially adsorbed onto the flyash while any ammonium salts formed are captured in the particulate control devices. Furthermore, the air preheater in a boiler plant is cleaned periodically by on-line “soot” blowers.

Operating combined cycle plants fired with sulfur bearing fuel oil have shown fouling of the low temperature boiler feed water heater in the HRSG when equipped with an SCR. Note that the salts that do not deposit within the HRSG will be emitted as particulate matter.

The use of SCRs in IGCC applications thus requires a syngas that is very low in sulfur content to reduce the SO_3 content in the gas turbine exhaust. SCRs have been installed in IGCC plants, the API Falconaro plant in Italy and the Negishi plant in Japan[5]. The ISAB IGCC plant in Italy which also has an SCR, uses it only on fuel oil operation and bypasses it during syngas operation[6]. For the Negishi plant, a syngas with a sulfur content of 8 ppmV is produced with a design maximum of 30 ppmV. No problems associated with salt deposition in the HRSG have been experienced in this plant. Both capital cost and thermal penalties are associated however, with deep sulfur removal in an IGCC for the following reasons:

- A COS hydrolysis unit may be required to convert the COS (which is more difficult to scrub out in the acid gas removal unit) to H_2S; and,
- A large circulation rate is required in the acid gas removal unit for deep sulfur removal.

In the case of an IGCC plant designed for producing a decarbonized syngas using sour shift and an acid gas removal unit to capture the CO_2 and also perform desulfurization of the syngas, most of the COS is hydrolyzed to H_2S in the shift reactors, while due to the very large solvent circulation rate maintained in the acid gas removal unit to capture the CO_2, the sulfur content of the treated syngas is very low. In such cases, the incremental heat rate and cost penalties associated with producing a low sulfur syngas suitable for firing in a gas turbine equipped with an SCR are not significant.

Engine Output

The gas turbine when fired with syngas with diluent addition can be fully loaded to maximize its power output, the limits being the surge margin of the compressor (pressure ratio being increased) and the shaft torque. A nearly “flat rating” of the engine output with respect to the ambient temperature may be realized by opening up the guide vanes as the ambient temperature increases, the compressor inlet guide vanes being typically closed at the lower ambient temperatures to compensate for the larger mass flow rate of the syngas and the diluent.

1.2.2-3 Conclusions

Due to the high H_2 content of the syngas stream, the use of current design pre-mixed gas turbine combustors to limit NO_x formation is precluded. Diluent addition is required to the syngas in order to reduce the NO_x generation when utilizing diffusion type combustors; the amount of diluent addition required by decarbonized syngas is much higher that that required for the un-decarbonized syngas.

The H_2O vapor content of the working fluid flowing through the turbine, especially in the case when decarbonized syngas is the fuel and while utilizing water vapor as the diluent, is significantly higher than that in the case when natural gas is the fuel. The implications for the gas turbine in such applications are that the turbine firing temperature is derated due to the different aero-heat transfer characteristics and due to the higher cooling air temperatures caused by operation under a higher pressure ratio, while the life of the thermal barrier coatings and any ceramics that may be utilized in advanced gas turbines in the future may be adversely effected.

Use of a trapped vortex combustor holds promise as an alternate option for supressing the NOx emissions in syngas application.

Penalty of utilizing a SCR in a decarbonized syngas fired combined cycle can be less severe as compared to its use in an IGCC without upstream CO_2 capture.

1.2.2-4 Notes

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1. A.D. Rao and R. Stobbs,, "An Evaluation of Coal Gasification with CO_2 Capture" (presented at the Combustion Canada Conference, Vancouver, September 2003); EPRI Report No. IE-7365, "Engineering and Economic Evaluation of CO_2 Removal from Fossil-Fuel-Fired Power Plants" (prepared by Fluor Daniel, Inc, June 1991).
2. See note 1 above (EPRI Report).
3. A.D. Rao and D. Du Plessis, "Prospects for 200 MW Western Canadian Coal IGCC with CO_2 Capture" (presented at the Combustion Canada Conference, Vancouver, September 2003).
4. K.Y. Hsu, L.P. Gross, and D.D. Trump, "Performance of a Trapped Vortex Combustor" (J. of Propulsion and Power, Paper No. 95-0810, AIAA 33rd Aerospace Sciences Meeting and Exhibit, Reno, Nevada, Jan 9-12, 1995).
5. T. Ono, "NPRC Negishi IGCC Startup and Operation" (presented at the Gasification Technologies Conference, San Francisco, California, October, 2003); D. Heaven and B. DeSouza, "Technical Issues with SCR in IGCC Applications" (presented at the 6th European Gasification Conference, Brighton, UK, May 2004).
6. See note 5 above (Heaven & DeSouza).

BIOGRAPHY

1.2.2 Implications of CO_2 Sequestration for Gas Turbines
1.3.2 Advanced Brayton Cycles

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Dr. Rao serves as the Chief Scientist, Power Systems at UC Irvine Advanced Power and Energy Program. He worked in industry for more than 30 years in the energy conversion area, and previously worked at Fluor as Director in Process Engineering and Senior Fellow in design / development of gasification for power generation and synthetic fuels coproduction. He received several patent awards in the energy conversion area and authored several papers on advanced power cycles and improved IGCC designs. Dr. Rao has also worked for Allis-Chalmers and McDowell Wellman Engineering in coal conversion; responsibilities included taking ideas from drawing board to demonstration scale plants. He holds a Ph.D. in Mechanical Engineering and a M.S. in Chemical Engineering.