Proceedings of ASME Turbo Expo 2011
GT2011
June 6-10, 2011, Vancouver, British Columbia, Canada

GT2011-45701

DEVELOPMENT OF H_2-RICH SYNGAS FUELLED GT FOR FUTURE IGCC POWER PLANTS – ESTABLISHMENT OF A BASELINE

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ABSTRACT

As part of the European Union (EU) funded H_2-IGCC project this work presents the establishment of a baseline Integrated Gasification Combined Cycle (IGCC) power plant configuration under a new set of boundary conditions such as the combustion of undiluted hydrogen-rich syngas and high fuel flexibility. This means solving the problems with high NO_x emitting diffusion burners, as this technology requires the costly dilution of the syngas with high flow rates of N_2 and/or H_2O. An overall goal of the project is to provide an IGCC configuration with a state-of-the-art (SOA) gas turbine (GT) with minor modifications to the existing SOA GT and with the ability to operate on a variety of fuels (H_2-rich, syngas and natural gas) to meet the requirements of a future clean power generation. Therefore a detailed thermodynamic analysis of a SOA IGCC plant based on Shell gasification technology and Siemens/Ansaldo gas turbine with and without CO_2 capture is presented. A special emphasis has been dedicated to evaluate at an intermediate stage of the project the GT performance and identify current technical constraints for the realization of the targeted fuel flexibility.

The work shows that introduction of the low calorific fuel (H_2 rich fuel more than 89 mol% H_2) has rather small impact on the gas turbine from the system level study point of view. The study has indicated that the combustion of undiluted syngas has the potential of increasing the overall IGCC efficiency.

1 INTRODUCTION

The continued need to use coal as primary fuel engenders both increased interest and concern while, in connection with coal gasification, generating a sincere demand for the development of reliable, low-emission, cost-competitive gas turbine technologies for hydrogen-rich syngas combustion. Integrated gasification combined cycle is currently one of the most attractive technologies for the use of coal with high efficiency and it offers the greatest fuel flexibility among the most advanced technologies for power production. In addition, gasification also provides an opportunity to control and reduce gaseous pollutant emissions such as NO_x and SO_x. It in addition offers one of the least costly approaches to concentrate carbon dioxide (CO_2) at high pressure to facilitate CO_2 capture and storage (CCS). However, coal-based IGCC plants have still not achieved any commercial breakthrough, even though research and development of IGCC plant technology began 40 years ago. The currently six IGCC power plants in the world, operating on coal as primary feedstock are demonstration plants with capacities of 250-400 MW [1].

The design and operational experiences along with the technical limitations of current state-of-the art IGCC power plants have been reported in the recent past [2]-[5]. Important contribution to field highlighting the two design variables affecting the gas turbine operation i.e. the integration level of the ASU and the nitrogen supply ratio for dilution of the syngas has been presented by Kim et al [6]. These two parameters do also have an influence on the turbine metal temperature. It has been shown that low integration degree designs cause overheating of the turbine metal due to higher pressure ratios. Overheating of the turbine metal also becomes more severe as the heating value of the syngas decreases. As a consequence of the increased fuel flow the pressure ratio is increased, which in turn gives higher temperature of the extracted air for turbine cooling [7]. Even though higher integration levels results in a higher IGCC efficiency [6] the operational experience from

Buggenum has shown that the highly integrated design layouts are problematic and has a negative effect on the plant availability.

With the last years growing concern about greenhouse gas emissions the near-term implementation of pre-combustion CO_2 capture technologies in IGCC applications has drawn increased R&D interest [8]-[11]. One of the most promising alternatives to the pre-combustion technology in IGCC power plants is the oxy-combustion IGCC [12], [13], having the potential of increasing both efficiency and environmental characteristics of coal power plants. However, the large oxygen consumption and required re-design of the gas turbine are still the main drawbacks [13]. Accordingly, this CO_2 abatement technology along with membranes, adsorption onto solids and cryogenic separation are different in terms of efficiency and cost compared to chemical or physical absorption of CO_2 and thus the realization of these are within the mid-long term time frame. Nevertheless, the capital costs associated with current SOA IGCC is a major challenge, especially compared to natural gas combined cycles. Adding the costs for implementing any near term CCS technology makes the challenge even greater [14]-[17]. In this context the high operational costs, coming at the top of the investment, is another drawback deriving from the currently low reliability and availability of the gasifier, reduced efficiency due to de-rating of the gas turbine, and the required syngas pre-treatment in terms of dilution.

Although IGCC offer significant advantages over pulverized coal (PC) plants in terms of cost effective reduction of CO_2 emissions, the main challenges including cost, compatibility with alternative technologies and the insecurity of the implementation of any future CCS remain critical obstacles for widespread commercialization [18]. Numerous research projects such as Australia's COAL21 National Action Plan, the European funded Clean Coal Technology activities under the 7th Framework Program, and the Canadian Clean Coal Technology Roadmap have thus been released in recent years. They are aiming at reducing these barriers by focusing on new coal feeding systems, novel H_2 production and purification processes, and CO_2 management [19].

In addition to capture, CCS involves two other major components: transport and storage. One of the biggest uncertainties in the CCS chain is finding suitable sites for the storage of CO_2 close to the emissions sources. Other storage issues that need be addressed are: storage capacity estimation, the potential for storage e.g. in deep saline reservoirs, understanding the CO_2 trapping mechanisms and quantifying the risks of CO_2 geological storage. Even though considerable progress has been made in understanding many of these issues trough the many research and demonstration projects around the world i.e. Sleipner, Weiburn, In Salah and Otway to mention a few, the regulatory framework and incentives for a near term implementation of CCS is still to be solved [20]-[22].

As a part of the EU funded H_2-IGCC project this work presents the establishment of a baseline IGCC power plant configuration under a set of new boundary conditions. An overall goal of the project is to provide an IGCC configuration with a SOA GT with minor modifications to the existing SOA GT and with the ability to operate on a variety of fuels (H_2-rich, syngas and natural gas) to meet the requirements of a future clean power generation. Therefore a detailed thermodynamic analysis of a SOA IGCC plant based on Shell gasification technology and Siemens/Ansaldo gas turbine with and without CO_2 capture is presented. A special emphasis has been dedicated to evaluate the GT performance and identify current technical constraints for the realization of the targeted fuel flexibility.

2 H_2-IGCC PROJECT

One of the largest barriers towards the usage of syngas in current IGCC power plants is its inherently variation in composition and heating value. At the same time the high content of H_2 in syngas derived from gasification of coal complicates the application of pre-mix burners (Dry Low Emission of Dry Low NO_x burners), which is current SOA in natural gas fired GTs. The restriction of using DLE burners is due to the higher reactivity of H_2 compared to natural gas. For this reason GTs in existing IGCC power plants are utilizing high NO_x emitting diffusion burners that also requires the hydrogen-rich syngas to be diluted with nitrogen or water/steam to control the higher adiabatic flame temperature.

Given these limitations the overall objective of the H_2-IGCC project is to provide and demonstrate technical solutions which will allow the use of SOA highly efficient, reliable GTs in the next generation of IGCC plants. The goal is to enable combustion of undiluted hydrogen-rich syngas with low NO_x emissions and also allowing for high fuel flexibility by enabling the burning of back-up fuels, such as natural gas, without adversely affecting the reliability and availability.

The project is divided into the following four technical subprojects (SP)[23]:

Combustion (SP1) – development and demonstration of safe and low emission combustion technology for undiluted, hydrogen-rich syngas.

Materials (SP2) – development and demonstration of improved materials systems with advanced coatings able to protect base blade and combustor materials against the different and potentially more aggressive temperatures and compositions of exhaust gases.

Turbomachinery (SP3) – investigation of modified compressor/turbine aerodynamics and hot path cooling in order to manage the increased mass flow rate of fuel and the increased heat transfer of exhaust gases.

System Analysis (SP4) – evaluation of optimum IGCC plant configurations and establishment of guidelines for optimized full scale integration while providing detailed system analysis to generate realistic techno-economical results for future gas turbine based IGCC plants with CCS.

3 METHODOLOGY

This work covers the description of the current thermodynamic model set-up of the whole IGCC cycle including important aspects of assumptions and limitations as well as a discussion of the results. A special emphasis in this regards has been given to the GT since this component is the major of the overall H_2-IGCC project.

The thermodynamic model set up, described by the mass and energy balances of the IGCC plant with gasification of coal and pre-combustion CO_2 capture has been established based on commercially available technology:

- oxygen-blown, entrained flow coal gasifier (Shell technology),
- sour water-gas-shift (WGS) reactors,
- physical absorption using Selexol solvent for acid gas removal (AGR),
- power island consisting of a 300 MW single shaft gas turbine based on the Ansaldo Energia 94.3A with a conventional triple-pressure steam cycle as the bottoming cycle.

The focus of utilizing SOA technology is an important element of the overall project. Thus the foundation of the reference IGCC layout provides a fairly conservative baseline for future studies. At the end of the project the goal is to find the optimum combination of commercial gasification units with modified gas turbines, incorporating solutions to the technical challenges of burning undiluted hydrogen-rich syngas at an appropriate level of integration.

Modelling of the IGCC power plant has been made using three different modelling tools:

- Enssim – Simulation tool developed by Enssim Software.
- Aspen HYSYS – Commercial process simulator by AspenTech [24].
- IPSEpro- Commercial heat and mass balance programme by SimTech [25].

The reason for using a combination of several simulation tools is that each of the selected tools have shown advantages when simulating different parts of the IGCC plant in terms of providing reliable results and the possibility of incorporating detailed component characteristics. Hence, the simulation tool among these three satisfying these requirements for each sub-system to the greatest extent has been selected as described below:

- The detailed modelling of the Shell gasification process including the process components: coal milling and drying, gasification, raw syngas cooling and scrubbing have been performed by Nuon using the Enssim modelling tool.
- The required compression work in the air separation unit (ASU) has been calculated using Aspen HYSYS (Peng-Robinson equation of state (EOS)).
- The syngas cleaning downstream the wet scrubber has been modelled by first simulate the mixing of raw syngas and steam in Aspen HYSYS (Peng-Robinson EOS) while the subsequent shift and two stage acid gas removal has been performed in the heat and mass balance program IPSEpro. In the case when no capture of CO_2 takes place the syngas leaving the wet scrubber is bypassed to the H_2S absorber before entering the power island (without any dilution).
- The clean syngas leaving the CO_2 absorber/H_2S absorber is directed to the GT, which together with the triple-pressure steam cycle is modelled in IPSEpro.
- The CO_2 captured in the second absorber in the AGR process is compressed in a seven-stage intercooled compressor and finally pumped to appropriate transportation conditions. This part has also been completed using the Aspen HYSYS modelling tool (Peng-Robinson EOS).

Data exchange between these codes was done manually and iterated for optimal match.

Even though three different tools have been used for simulating the whole IGCC power plant with as well as without CO_2 capture, the main platform for the simulations is IPSEpro and the aim is to be able to simulate the whole IGCC except from the gasification island in the IPSEpro environment by solving current limitation in terms of pressure of pure gaseous streams. The main reason for using IPSEpro as basis for the simulations is the comprehensive model library, which has been developed as a result of many years work within the research group of University of Stavanger. This includes detailed and sophisticated models of various power plant components that have been developed due to the main advantage of IPSEpro, allowing for introducing new and modified components in a very straight-forward and flexible manner. This advantage is very important in this project as the GT model will need to be adapted to certain changes based on the results from the different SPs. IPSEpro also provides additional benefits in terms of thermo-economical optimization features that will be of major significance to achieve the overall project target of finding optimum combination of commercial gasification units with modified gas turbines and appropriate level of integration. The schematic outline of the IGCC with CO_2 capture is illustrated in Figure 1.

4 IGCC POWER PLANT DESIGN

4.1 Coal input

Bituminous coal being a mixture of various trade coals on the world market (mainly Russia, but also USA, Columbia and South Africa) with the composition according to Table 1. It is milled and dried to a moisture level of 2%wt, and fed to the gasifier by means of lockhopper pressurization using pressurized N_2 as conveying gas. Heat for drying is provided by burning approximately 0.9% of the shifted syngas. The amount of coal needed is determined by the thermal power required by the gas turbine model, based on the Ansaldo Energia 94.3A GT. The resulting coal input is within the range of 1’008 -1’110 MW_{LHV}.

Table 1 – Composition (% by weight) and heating value of as received of the Bituminous coal used in the calculations.

C	64.10	Moisture	10
H	3.90	Ash	12.50
N	0.70		
O	7.21		*kJ/kg*
S	1.50	HHV	26195
Cl	0.09	LHV	25100

4.2 Air separation unit

The ASU is a stand-alone unit generating oxygen with a purity of 95mol% (with 2% N_2 and 3% Ar) from air supplied by the non integrated main air compressor (MAC). Selection of the non- integrated MAC was motivated by negative experiences concerning plant availability, from partially or fully integrated ASU systems. The MAC is a seven-stage intercooled

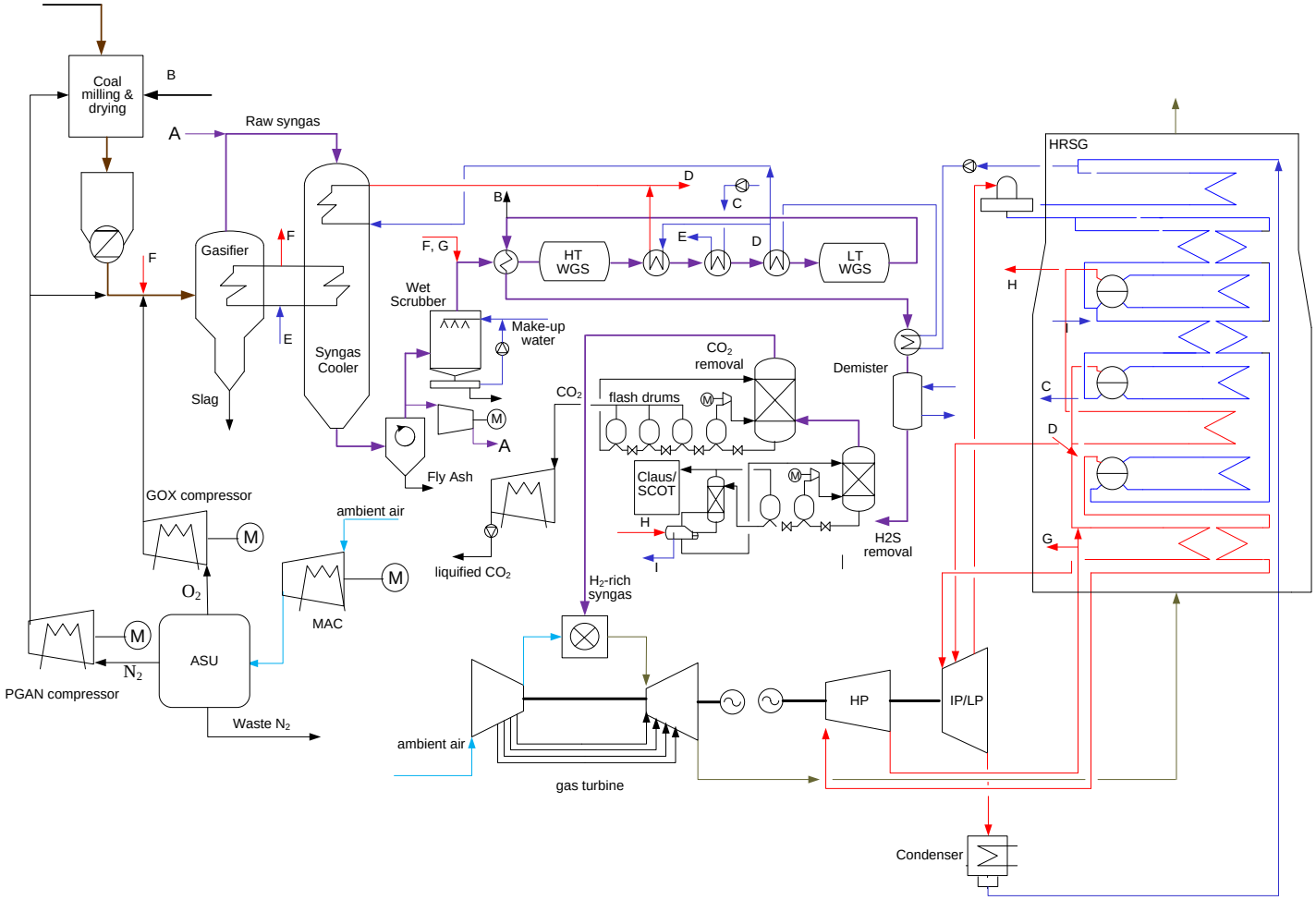

Figure 1 – Plant schematic of the Shell IGCC with CO_2 capture and conventional WGS

compressor with a discharge pressure of 5.5 bara. The gaseous oxygen (GOX) is compressed to 55 bara in a nine-stage intercooled compressor and fed to the gasifier while the pure gaseous nitrogen (PGAN) is compressed to 80 bara in a ten-stage intercooled compressor used for fuel feeding to the gasifier. Since the GT is operated on undiluted syngas all remaining nitrogen from the ASU not needed in the gasification island is vented to the atmosphere. For further technical assumptions for the air separation unit please see Table A1 in Annex 1.

4.3 Gasification, syngas cooling and scrubbing

The gasification of the coal is taking place in an O_2-blown, entrained flow gasifier based on the technology licensed by Shell [26]. The gasification process (technical assumptions presented in Table A2 in Annex 1), in which the milled and dried coal is gasified in the presence of intermediate pressure (IP) steam and oxygen is modelled assuming full equilibrium at 45 bara and 1600 °C. This condition determines the composition of the raw syngas and it is achieved by adjusting the O2 to coal mass ratio while setting the heat loss to the membrane wall to 2.5% (LHV). The single pass and overall

carbon conversion rate is 99.3% (no recycling of fly ash) and the fine particles that are not captured as fly ash by the ceramic filter (after syngas cooling) leave the bottom of the gasifier as vitreous slag.

The raw syngas from the gasifier is first cooled to 900 °C by adding a stream of recycled, cooled, ash-free syngas in order to lower the gas temperature below the ash melting point. The raw syngas is then further cooled to 340 °C in syngas coolers that evaporate high pressure (HP) and IP pressure boiler feedwater to produce HP steam for the steam cycle and IP steam to be used in the water-gas-shift process. After passing the dry particulate filters removing the fly ash, a small part of the raw syngas is recycled back (0.84%) for cooling the raw syngas exiting the gasifier. The rest is sent to the wet scrubber for removal of species soluble in water, and trace particulate matter such as unconverted carbon, slag and metals. The quenched and cleaned syngas leaving the scrubber has a temperature and pressure of 165 °C and 43 bara respectively. However, the dry-feed characteristics for the Shell gasifier leaves the raw syngas with a relatively low steam-to-CO ratio thus requiring injection of steam to insure adequate CO to CO_2 conversion during the WGS. The IP steam for this purpose is partly supplied from the syngas cooler, but since the requirement is larger than the amount generated in the gasifier the rest is bled from the HP/IP turbine crossover. In order to promote the WGS reaction sufficiently and to avoid carbon formation on the WGS catalyst the steam-to CO ratio has been adjusted to 2.4 (molar basis).

4.4 Water-gas-shift

The water-gas-shift process is the reaction used to convert most of the CO in the raw syngas into CO_2, by shifting the CO with water over a bed of catalyst. Besides CO_2 hydrogen is generated in this reaction (Eq.1). In IGCC applications with CO_2 capture this is the first step in order to convert the gasifier product into a hydrogen-rich-syngas. The CO converter is located upstream of the AGR unit (sour shift) and is arranged as two reactors in series to meet higher CO_2 capture rates. The WGS reaction is exothermic (44 KJ/mole$_{CO}$) and it is thermodynamically favoured at lower temperatures, where reaction rates are comparatively slow. However, catalyst activity is in general higher at high temperatures.

$$CO + H_2O_{(vap)} \rightarrow CO_2 + H_2 \quad (1)$$

The scrubbed and steam mixed syngas is pre-heated to 250 °C before entering the first stage of the WGS unit. The syngas leaving the first high temperature (HT) reactor is cooled down from the equilibrium temperature of 463 °C to 250 °C by generating HP steam and it then enters the low temperature (LT) WGS reactor. The warm syngas leaving the second reactor at an equilibrium temperature of 278 °C is cooled to 25°C by means of preheating the raw syngas entering the first WGS reactor and by preheating HP boiler feedwater. The resulting overall adiabatic conversion of CO to CO_2 and H_2 in the WGS process is 98.9% (molar basis). The cooled shifted syngas is passed through a demister before being sent to the acid-gas removal. The total pressure loss of the syngas from the exit of the wet scrubber to the exit of the demister is 9.1%.

4.5 Acid gas removal

During gasification, sulphur in the raw coal is converted to H_2S and COS. Nevertheless, in the CO_2 capture case most of the COS is converted to H_2S during the WGS reaction. The H_2S and CO_2 are removed from the shifted syngas in a two-stage physical absorption system using dimethyl ether of polyethylene glycol also known as Selexol. The syngas enters the first absorption column in which the H_2S is removed by a counter current flow of the solvent. The acid gases in the rich solution exiting the bottom of the absorber column is flashed and then stripped off in a regenerator for which heat (approximately 13.6 MW_{th}) is provided from steam bled from the LP steam turbine. The regenerated solvent is cooled and recycled back to the top of the absorber while H_2S is sent to a sulphur recovery unit including a Claus plant for oxidizing H_2S to elemental sulphur and a Shell Claus off gas treating (SCOT) plant for tail gas cleanup.

After leaving the H_2S absorber the syngas enters the second absorber for removal of CO_2. Similar to the removal of H_2S the CO_2 is absorbed by the solvent flowing downwards the column and exits the bottom of the column with the CO_2 solved in the solution. This collected rich CO_2 solvent exiting the bottom of the tower is passed through four flash drums connected in series, where CO_2 is released as a result of lowering the pressure. The lean solvent leaving the last flash drum is pumped and returned back to the top of the absorber column. The release of the pressure of the rich solvent between the column and the different flash drums is achieved by hydraulic turbines. In this way part of the solvent pumping power could be recovered. The solubility of CO and H_2 in Selexol is low, but not negligible, hence in order to minimize the amount of H_2 and CO that are co-absorbed with the CO_2 in the absorber and thereby lowering the heating value of the fuel. The gas leaving the first flash drum is recycled back to the absorber column, since virtually all H_2 and CO absorbed is released in this drum. The CO_2 released in the flash drums two to four is sent to compression. The CO_2 removal rate in the AGR unit is 96.3% (molar basis), though, the overall CO_2 capture rate as defined in Eq. 4 is 88.6% (molar basis).

$$\frac{CO_2\ captured_{sent\ to\ compression}}{Carbon_{\ coal\ feed} - carbon_{fly\ ash} - carbon_{slag}} \quad (4)$$

In the case when CO_2 is vented, the raw syngas leaving the wet scrubber is passed through the demister before entering the H_2S absorber. The rich solution leaving the bottom of the column is regenerated and the sulphur is stripped off using IP steam produced in the gasification island. Since this amount is only partly sufficient the rest is extracted from the HRSG. However, since the solvent flow rate in this case is

considerably lower (the flow rate of dry raw syngas is lower than that of dry shifted) the thermal heat input is 3.6 MW_{th} lower than for the case with CO_2 capture. The H_2S poor syngas exiting the absorber top is passed to the GT combustor. For further technical assumptions for the AGR unit please see Table A3 in Annex 1.

4.6 CO_2 compression

The CO_2 collected in the flash drums in the CO_2 removal process is compressed in a seven-stage intercooled compressor to 60 bara, liquified and then pumped up to final pressure of 150 bara. The compressor/pumping approach has been evaluated in a previous work by the authors and found to be the most efficient approach [27].

4.7 Gas turbine model

The gas turbine model has been modelled based on internal project information exchange with the working group focussing on the GT design (SP3). This information included initial performance calculation results of a lumped turbomachinery model of the GT, Ansaldo Energia 94.3A, with a first version of the compressor map and some turbine data. All information received was based on natural gas as fuel. The control algorithm currently adopted when burning undiluted hydrogen-rich syngas and cleaned syngas is without any major modifications to the natural gas operation:

- The turbine inlet temperature (TIT) was fixed to 1331 °C.
- The compressor variable inlet guide vanes (VIGV) are slightly closed to adjust for the increased fuel flow by reducing the air mass flow.
- Due to the increased fuel flow the model adjusts the pressure ratio accordingly.

The GT models used at current state have some limitations for off-design calculations, as only subsections of the compressor- and turbine maps are implemented, there is no detailed modelling of the cooling flows, etc., but will be handled as soon as more information from other teams within the project will be available. Nevertheless, the current model is built up accordingly:

Compressor model – In terms of the speed lines, a characteristic has been used which is, according to the authors, reflecting state of the art characteristics Besides, cooling air extraction at different pressure level has not been considered as this information was not available at this time. However extractions are already part of the model and can be activated when needed. It is planned that the characteristic currently in use is going to be replaced as soon as a more detailed version of the compressor map is available.

Combustor model – The fuel composition to the combustor was calculated using the detailed models described above (4.1 - 4.5). Besides, a pressure loss reflecting current state of the art technology was used. This will also be updated later on according to the results provided by the working group for combustion. Fuel pre-heating has not been included, but will be considered in the optimization of the whole IGGC plant.

Turbine model - The turbine part has been modelled using a simplified approach based on the input received. The turbine model used in this work has been assumed with a constant hot gas flow, even though the real turbine is cooled and cooling air is mixed into the hot gas at different stages this was not considered in the existing model. In order to never the less cover the overall performance of the turbine the turbine-, inlet temperature and efficiency are calculated in terms of virtual measures according to following equations:

$$T_{tmixed\ Turbine\ inlet} = \frac{P_{shaft}}{\dot{m}_{total}\, cp} + T_{t\ Turbine\ exit} \qquad (2)$$

and

$$\eta_{T\ poly\ mixed} = \frac{cp}{R_{exit}} \frac{\ln\left({}^{T_{tmixed\ Turbine\ inlet}}/_{T_{t\ Turbine\ exit}}\right)}{\ln\left({}^{p_{t\ Turbine\ inlet}}/_{p_{t\ Turbine\ exit}}\right)} \qquad (3)$$

This has been done to match the data received from the turbomachinery working group. By doing so the general expansion in the turbine (mainly the pressure ratio and therefore also the power consumption in the compressor) as well as the overall power output was met. The technical assumptions for the GT are presented in Table A4 in Annex 1.

The above described simplifications are an often used approach in the early stage simulation of a GT process. These models are going to be replaced by more detailed ones as soon as this information will become available.

4.8 Heat recovery steam generator design

Downstream the GT is a three pressure level heat recovery steam generator (HRSG) with reheat. The admission levels have been set according to internal discussions and agreements within SP4. The superheating temperature has been set to 530 °C in order to meet the GT exhaust temperature and the required amount of HP steam needed to be superheated. The heat integration represents somewhat a first approach and has not been optimized. The assumptions of the parameters of the HRSG are considered to be conservative in terms of pressure losses, approach temperatures, steam turbine efficiency, etc. There is potential of increasing the HRSG efficiency in order to maximize the net electrical output, however the economical feasibility of such optimization should not be disregarded.

The IP and HP boiler feedwater (BFW) needed in the gasification island is taken from the HRSG and all HP steam is returned back to the HRSG and mixed with the HP steam produced in the WGS and superheated before expanded in the steam turbine. The IP level has been set to meet the pressure of the syngas leaving the wet scrubber 43 bara, since a considerable amount of IP steam is extracted from the HRSG in the case with CO_2 capture and mixed with the raw syngas in

Table 2 – Performance results of the IGCC power plant with and without CO_2 capture

	IGCC w.	IGCC w.o.	
GT power out	324.07	309.39	MW
ST shaft power	166.30	211.43	MW
HRSG pumping power	3.54	3.13	MW
AGR turbine power out	3.42	-	MW
AGR pumping/ compr. power req.	11.39	0.2	MW
ASU compression power req.	40.88	37.14	MW
Gasification power req.	4.96	4.50	MW
CO_2 compression power req.	18.06	-	MW
Net power out	414.96	476.86	MW
Net IGCC efficiency (LHV)	37.40	47.20	%

order to perform the WGS reaction. The IP steam produced in the gasifier island has a pressure of 50 bara, thus the BFW extracted for this purpose is pumped to appropriate pressure and heated by utilizing a small part of the heat generated in the HT part of the WGS. The assumptions made for the HRSG calculation are presented in Table A5 (Annex 1).

In the case without CO_2 capture the HP BFW for the gasification island is extracted in the same manner as in the case with CO_2 capture, however all the HP steam produced is returned back to the HRSG and superheated to 500°C. The IP BFW for is extracted similarly as for the CO_2 capture case and the small amount IP steam not needed in the gasification island is used for regenerating the solvent in H_2S removal unit. Since the IP steam needed in the H_2S removal is higher than the amount produced in the gasification island the additional required is bled from the HP/IP crossover. The IP SH/RH temperature has likewise the HP SH temperature for the CO_2 venting case been lowered with 30°C to 500 °C to accomplish the superheating of all steam produced in the gasifier as well as the steam no needed for the WGS. All other assumptions for the HRSG are presented in Table A5 in Annex 1.

5 RESULTS AND DISCUSSION

The performance of the IGCC power plant with and without CO_2 capture based on the calculation using the models as previously described are presented in Table 2 and the composition of the syngas for the two cases are given in Table 3. The IGCC without CO_2 capture has a somewhat lower efficiency, even though the syngas in this work is not diluted, than a similar case presented last year by Kreutz et al [17]. The main reason for this is that the reference GT used in this work is less efficient than the General Electric 9 FB even though the TIT was de-rated to 1327°C in the previous work. Nevertheless, the syngas considered was highly pre-heated and the HRSG fully optimized, which are issues within the scope of future activities within this project. The net efficiency of the case with CO_2 capture and undiluted hydrogen rich syngas is on the contrary demonstrating a higher efficiency compared to the same publication. This is due to a slightly difference in the steam-to- CO ratio between the present study and the one presented in [17]. In addition the higher heating value of undiluted syngas results in a significantly higher GT power output. Since the HRSG in this study has still not been optimized the genuine improvement using undiluted syngas is to be determined. The initial results have though confirmed that without considering any any modifications of the GT and keeping the efficiency constant, the power output from the engine could increase with as much as 30 MW (compared to the same GT fired with natural gas).

The big differences in fuel composition between natural gas, hydrogen-rich syngas and cleaned syngas will most probably result in different designs of the combustion system as well as compressor and turbine to maintain stable combustion and to keep the pressure ratio for the different mass flow ratios in turbine and compressor. The extent of these changes or requirements will be revealed within the project in a near future and will be implemented in the GT model, giving the opportunity to optimise the processes for the various cases.

However, Table 3 summarizing the two different fuel compositions directly indicates that two different combustor designs might be essential given the huge differences in the properties, which are difficult to be covered in a single design. The resulting difference in turbine inlet flow due to the huge difference in fuel flow will either require a compressor design with high efficiency over a wider range of IGV positions, or also two different designs. This topic, which is closely connected to transients and operation at off-design, will be addressed during the next steps within the project.

The turbine outlet temperature (562°C and 588°C respectively) as well as the turbine flow (700 kg/s and 749 kg/s respectively) is higher for both IGCC cases compared to natural gas (576°C /698 kg/s), which favours the steam bottoming cycle. However, there is an important difference in terms of extraction of BFW and steam along with returning condensate and steam from different parts of the IGCC power plant for the two cases investigated. This will have a major impact on the investment costs if the targeted fuel flexibility ranging from natural gas to cleaned syngas is going to be met. The further optimization of the two cases (with and without CO_2 capture) should thus be performed taking into consideration to reduce these distinctions to the greatest extent possible. In addition some aspects of changed conditions for component lifetime need to be evaluated since the lifetime due to the above mentioned increases i.e. the gas temperature of the un-cooled blade rows of the GT under certain operating conditions and could if not designed for have certain negative impacts on plant availability and costs.

The current overall CO_2 capture rate for the hydrogen rich case is 88.6 mol%, although the removal rate in the AGR unit is approximately 96.3 mol%. The reason for this significant difference is due to CO_2 lost in the H_2S absorber. The current outline of the AGR unit has not been optimized; hence a minimization of absorbed CO_2 in the first stage of the AGR will be further investigated by finding a more convenient combination of number of flashes as well as the extent of solvent pre-loading. Currently there is also a deviation in pressure loss in the H_2S absorber for the two cases due to pressure limitations in IPSEpro for pure gaseous streams which

limits the pressure, to 35 bara, in the case where the syngas is sent for further removal in second stage. This has an impact on the removal of CO_2, since physical absorption is favoured at higher partial pressures.

Table 3 – Composition (wt%) and characteristics after AGR of the hydrogen-rich and cleaned syngas respectively (undiluted)

	Hydrogen-rich syngas	Cleaned syngas
CO	0.0448	0.7857
CO_2	0.1078	0.0716
H_2	0.3595	0.0262
N_2	0.4879	0.1165
Fuel flow (kg/s)	17.67	70.78
LHV (kJ/kg)	43641	11100
Temperature °C	25.6	25.24
Pressure (bara)	34.5	42.4

6 CONCLUSIONS

As part of the EU-funded H2-IGCC project this work has described the establishment of two fairly conservative baseline IGCC cycles aimed for further investigations. The first IGCC power plant has been modelled with pre-combustion separation of CO_2 while the second is without the application of CO_2 removal resulting in two completely different syngas compositions. Both IGCC power plants are based on the GT Ansaldo Energia 94.3A without any dilution of the syngas. By performing new gasifier calculations including fly-ash recycle, optimizing the heat integration and implementing the characteristic GT data there is a potential to increase the net efficiencies of both plants beyond current values of 37.4% for the IGCC power plant with CO_2 capture and 47.2% for the case with CO_2 venting. The overall CO_2 capture rate presented in this work, 88.6mol% is somewhat low due to lost of CO_2 in the first AGR stage. A more favourable configuration of the H_2S removal unit will be further investigated to demonstrate higher capture ratios.

ACKNOWLEDGMENTS

The authors wish to acknowledge Nuon and E.ON for their technical input and truthful discussions in the early phase of this work. The authors are also grateful to Han Raas at Nuon for performing the gasification simulations. The authors would also like to acknowledge the project partners in SP3 for providing the gas turbine performance data.

NOMENCLATURE

AGR	Acid gas removal
ASU	Air separation unit
BFW	Boiler feed water
CCS	Carbon capture and storage
CO_2	Carbon dioxide
DLE	Dry low NO_x emission
EOS	Equation of state
GT	Gas turbine
H_2	Hydrogen
H_2S	Hydrogen sulfide
HP	High pressure
IGCC	Integrated gasification combined cycle
IP	Intermediate pressure
LP	Low pressure
mol	Molar
NO_x	Nitrogen oxide
SO_x	Sulphor oxide
SOA	State-of-the-art
SP	Subproject
ST	Steam turbine
TIT	Turbine inlet temperature
WGS	Water-gas- shift
wt	Weight

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ANNEX A

TECHNICAL ASSUMPTIONS USED IN THE MODELLING

Table A1 – Technical assumptions for the ASU

Delivery pressure/temperature of O_2 and N_2 by ASU	1.2/10	bara/°C
Main air compressor polytropic efficiency	87	%
GOX compressor polytropic efficiency	87	%
HP PGAN compressor polytropic efficiency	87	%
Inter-cooling temperature	40	°C

Table A2 – Technical assumptions for the Shell gasification island including the syngas conditioning downstream to the wet scrubber exit

Dried coal moisture content	2	wt%
Gasification pressure/temperature	45/1600	bara/°C
Shifted syngas for drying	2.2	wt% (of total flow)
Steam/coal ratio	0.061	kg / kg coal (ar)
O_2/coal ratio	0.7839	kg / kg coal (ar)
HP PGAN/coal ratio	0.241	kg / kg coal (ar)
Power requirement	112	kJ_{el}/kg coal (ar)
Heat loss to membrane wall	2.5	% coal LHV
Carbon conversion (single pass/overall)	99.3	%
Syngas cooler pinch-point HP evaporator	30	°C
Syngas cooler pinch-point IP evaporator	64	°C
Heat exchanger heat loss	0	%
Pressure drop syngas cooler (gas side)	0.33	bar
Pressure drop wet scrubber	1	bar
Water pump mechanical efficiency	85	%
Steam-to-CO ratio at WGS inlet	2.4	

Table A3 – Technical assumptions used for the AGR unit

	CO_2 capture	No CO_2 capture	
Syngas pressure/temperature at H_2S absorber inlet	39.1/25	43.96/25	bara/°C
CO_2 co-absorbed in H_2S absorber	9.5	8.5	wt% (of inlet)
Syngas pressure/temperature at CO_2 absorber inlet	35/25.7	-	bara/°C
Pressure loss in 1st/2nd absorber	4.1/0.5	0.5	bar
H_2S stripping duty	13.6	10	MWth
H_2 co-absorbed (overall)	0.35	0.1	wt% (of inlet)
CO co-absorbed (overall)	1.2	0.2	wt%
Solvent pumps polytropic efficiency	70	70	%
Compressor isentropic efficiency (recycle gas)	85	85	%
Hydraulic expander isentropic efficiency	85	85	%
Mechanical and electrical efficiency	99	99	%
Solvent temperature at absorber inlet	25	25	°C

Table A4 – Technical assumptions used for the gas turbine

Ambient air pressure	1.013	bara
Ambient air temperature	15	°C
Moisture in air	60	%
TIT	1331	°C
GT outlet pressure	1.08	bara (total)
Pressure ratio	18.2	(target natural gas)
Electrical/mechanical efficiency	99/99.5	%

Table A5 – Technical assumptions used for the HRSG

HP/IP/LP	140/43/4	bara
SH and RH temperature	530*	°C
SH LP steam	300	°C
HP/IP/LP ST isentropic efficiency	88.5/89/91	%
ST and generator mechanical efficiency	99.5	%
Gas side HRSG pressure drop	0.04	bara
Generator electrical efficiency	98.2	%
Pump polytropic efficiency	70	%
Pump mechanical efficiency	95	%
Evaporator pinch point IP/LP	10/10	°C
Super heater pinch point	32	°C
Economizer pinch point	10	°C
Approach point temperature	5	°C
Condenser pressure	0.04	bara

* The superheating/reheat temperature for the case without CO_2 capture is 500°C, all other assumptions are the same.