

Feasibility of the integration of a molten carbonate fuel-cell system and an integrated gasification combined cycle

Authors

Paolo Greppi, Barbara Bosio*, Elisabetta Arato

(*) Corresponding author. Tel: +39 010 353 6505; Fax: +39 010 3532589; E-mail address: barbara.bosio@unige.it.

Affiliation

DICAT, University of Genova, Via Opera Pia 15, 16145 Genova, Italy

Abstract

IGCC (Integrated Gasification Combined Cycle) power plants look promising for the environmentally-friendly, large-scale production of electrical energy from low-cost fossil feedstocks such as coal or refinery residues.

In IGCC plants hydrogen is an intermediate product, as a syngas component, between the thermochemical section and the power section, which is a conventional combined cycle modified to handle this low-density fuel.

Replacing the conventional power section with a fuel cell, the IGFC (Integrated Gasification Fuel Cell) configuration promises lower emissions, higher efficiency and possibility to scale down to smaller sizes.

To explore the challenges and the feasibility of such an integration we have proposed putting a pilot-scale fuel cell system into operation within an existing, conventional IGCC, creating a hybrid fuel-cell-IGCC. Two innovative configurations have been proposed and

optimized for a pilot-scale MCFC-GT (Molten Carbonate Fuel Cell – Gas Turbine) system, based on a typical syngas for IGCC plants such as that in operation at ISAB Energy Srl. The system has been modelled using the LIBPF process simulation library.

Keywords

Fuel-cell system; IGCC Syngas; Water recovery; Process simulation; IGFC

Manuscript Classifications

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1. Introduction

IGCC (Integrated Gasification Combined Cycle) power plants can produce electrical energy from a wide range of low-cost fossil fuels (coal, heavy oils and refinery residues), in an environmentally-friendly way. Their economically-optimal scale is large, due to the complexity and the optimal-economical scale of the power section.

The integration of gasifiers and fuel cells in an IGFC (Integrated Gasification Fuel Cell) has been considered by several researchers ([1], [2], [3]), especially in relation to SOFCs (Solid Oxide Fuel Cells), although this technology still lacks many installed applications of significant size.

High- and medium-temperature fuel cells have lower emissions than combined cycles, with a competitively high efficiency and the possibility to scale down to smaller sizes (e.g. 1 MW, as described in [4]).

Of particular interest are the benefits obtained when carbon capture is coupled with IGFC,

highlighted in [5] and [6].

Molten Carbonate Fuel Cell (MCFC) technology is more mature than that of solid oxides and about a hundred energy plants in the range 250 - 1000 kW_e have been installed and are operating, mostly as distributed CHP (Combined Heat and Power) plants. Furthermore multi-MW fuel-cell plants based on MCFC technology are being tested now, opening up applications for conventional, concentrated production of electrical energy.

To obtain a proper IGFC system, an extensive reworking of the configuration must be expected, with particular attention to pressure levels, thermal integration and the handling of impurities.

As a first step, it is necessary to explore the challenges and the feasibility of the integration, for example the long-term behaviour of the fuel cell components when fed with an IGCC-type syngas. Therefore we have suggested putting a pilot-scale fuel cell system, with a configuration only minimally modified from that of the standard, standalone modules, into operation within an existing, conventional IGCC, resulting in a hybrid fuel-cell-IGCC.

Such an ideal pilot-scale system is smaller (about one-tenth) than the reference plant considered in [7]. This configuration, which results in a nominal electrical power system of 125 kW, was chosen as the starting point of this work. We have considered the plant of ISAB Energy Srl in Priolo Gargallo (Italy) for the IGCC for this work [8]. This unit has a maximum electrical power output of 570 MW and has operated since 2000 on heavy refinery residues from a Solvent Deasphalting unit, and alternatively on Vacuum Visbreaker Residue, Visbreaker Atmospheric Residue or Virgin Vacuum Residue.

The residues can be approximated as long-chain hydrocarbons with a gross chemical composition C_nH_{2n}. Due to the characteristics of the feedstock, the gasification based on the Texaco (now GE Energy) process, which runs under a pressure of 6 MPa [8] at

1300-1700 K, results in a syngas distinctively richer in hydrogen than syngas from coal-fired IGCC. The high hydrogen to carbon ratio of the syngas, which could be a drawback for the conventional power section of the IGCC [9], is an advantage for fuel cells.

The MCFC system, which is typically designed to run on hydrocarbon fuels and is, therefore, equipped with an internal or external reformer should then be adapted to allow integration with the IGCC: in particular the syngas, coming from the gasification and clean-up section, will be fed to the electrochemical MCFC section.

The syngas composition from of a residue-fired IGCC has distinctive characteristics being richer in carbon monoxide than the reformat of a gaseous hydrocarbon and richer in hydrogen than a coal-fired IGCC syngas. The composition can be approximated by assuming that 15% of the carbon in the feed is converted to soot, while chemical equilibrium at 923 K and 6 MPa is reached, except for methane formation. The charge is assumed composed by vacuum residues, oxygen (purity 95%, oxygen-residues ratio 1.13_w), and steam (steam-residues ratio 0.436_w) [8].

The feasibility of operating an MCFC system on an externally-produced syngas was studied, producing two alternative configurations.

2. Plant configurations

The two proposed configurations (A and B) for the MCFC-GT system are shown in the block diagrams in Figures 1 and 2 respectively, where the stream parts of the cathode loop are highlighted (bold) while the water-vapour circuit is in light blue. The two configurations share several common traits, but differ in:

- Size of microturbine;
- Water management;

- Cogeneration and heat recovery arrangement.

2.1 Common features

The fuel-cell energy-production plant is based on the flow scheme from a previous work [7] with the most notable difference being that in this case the reformer is not used, since the feedstock is a syngas and not a gaseous hydrocarbon stream. A detailed description of the constraints that must be imposed to guarantee safe operation (stack inlet temperatures, reactant concentrations, utilisation factors and the maximum temperature inside the stack plane) can also be found in reference [7].

The plant consists of a pressure vessel containing one planar, rectangular cross-flow stack and the common plant balance: catalytic burner, recycle blower, heat recovery, superheater, condenser (if present) and shift reactor.

The reference plant [7] was based on 150 cells per stack; here the number of cells has been increased to 200 to lower the current density (at constant electrical power output) and increase the robustness; in this way the pilot plant will stay within the safe operating region (maximum local temperature, pressure drops, load factor constraints) with greater margins.

A shift reactor has been introduced to prevent an undesired heat release on the anodic side when the exothermic water-gas-shift reaction, triggered by the catalyst, converts the high amount of carbon monoxide present in the syngas to carbon dioxide.

The Gas Turbine Sub-system (GTS) is a turbine-driven air-compressor, typically based on a standard, off-the-shelf package unit; the auxiliary natural gas feed (GTS fuel) is only required during nominal operation for Configuration A, and not for configuration B, although it might be required during start-up.

The low water-content of the syngas is compensated for to maintain the Oxygen to Carbon

atom ratio (required to prevent carbon-black deposition) by the addition of a proportional amount of pressurised steam; the saturated, pressurised water vapour recovered from the gas turbine exhaust in the Steam Production Sub-system is superheated in a separate exchanger (Superheater) located at the anodic inlet (configuration A) or the anodic outlet (B), to prevent condensation.

The exhaust fumes from the Steam Production Sub-system provide a thermal energy output in the cogenerative heat exchanger. Configuration B also produces some additional thermal energy from the partial condensation of the anodic outlet.

2.2 Optimised microturbine sizing

The GTS for configuration A is based on a standard, commercially-available microturbine with a nominal electrical power of 100 kW and already used for integration with 500 kW FC systems.

The nominal microturbine power should be 20 - 30% of the nominal FC power, so a microturbine with nominal electrical power of 25 - 37.5 kW would be preferable. A survey of commercially-available microturbines revealed that a 30 kW unit is available and should be sufficient to drive the system at a higher pressure (+14%) and with a higher air flow (+33%) than required.

Pending a verification of feasibility with the supplier, it has been assumed that the 30 kW microturbine can operate at the lower pressure, with the syngas combustion fumes and with a turbine-inlet temperature about 200 K lower than the nominal one, without auxiliary natural gas and with a complete recuperator bypass.

2.3 Water condensation and recovery

Water is a product of the combustion and the electrochemical reactions taking place in FCs; if this water is recovered from the exhaust by condensation, more enthalpy can be

obtained from the reactions, effectively utilising the HHV (Higher Heating Value) rather than the LHV (Lower Heating Value) as in condensation boilers [10].

But in this area the superiority of the fuel cells over conventional external or internal combustion engines is apparent: the fuel cells segregate the combustion reaction educts, that is carbon dioxide and water (mainly found in the anodic outlet), from the oxidant and inerts (found in the cathodic outlet).

This makes it reasonable and possible to condense the water from the anodic outlet, a gaseous stream with a very high water-vapour concentration, ranging from 50 to 57% in moles. To achieve this for configuration B, the anodic outlet passes through the steam superheater, a heat recovery system and a condenser before proceeding to the burner.

Just condensing the combustion water would produce an undesired waste-water stream. This waste stream would not be as polluted as the one from condensation boilers (because the fuel in this case is subject to much more stringent requirements, in particular regarding sulphur contamination) but could be a nuisance requiring dedicated handling and considerable bureaucratic paperwork.

Since water is also a feedstock for an MCFC-GT system, it makes sense to close the water balance by supplying the required water using the condensate, with the double advantage of zero waste-water and zero demineralised-water feed. This modification was implemented in configuration B as well.

Although a liquid-water handling system will be required for start-up and shut-down and to act as a buffer, and water treatment of some sort will be required to avoid the accumulation of impurities (soot, organics) in the water loop, these components have not been considered for the sake of simplicity.

2.4 Increased cogeneration efficiency

The impact of the water circuit on the thermal balances is heavy, in the range of 30% of the total energy turnover (LHV). In configuration B the higher thermal level part of the anodic outlet sensible heat is recovered to superheat the water vapour.

The rest of the cooling duty of the anodic outlet partial condenser is used for the heat recovery of the incondensable stream and then discharged in the form of waste heat for cogeneration (COGEN2). This condenser can also be used to manage the water inventory, to avoid water accumulation or loss: increasing the condensation temperature causes more water to enter the cathodic recycle loop in the gas phase and partially leave the FCS as exhaust fed to the GTS.

3. Theory and calculation

The steady-state process simulation was performed using LIBPF 0.8 (LIBrary for Process Flowsheeting), a process flowsheeting and modelling tool arranged as a C++ library.

The nominal point of operation of configuration A was computed once with the rigorous, distributed-parameter reference model for the fuel cell stack, with 24 x 16 discretisation units.

For all the subsequent simulation runs an intermediate-fidelity distributed-parameter model with a coarse discretisation of three units along the direction perpendicular to the cathodic flow, and two units along the orthogonal direction was used. The values of the two empirical parameters introduced in [7] to compensate for the effect of the coarse-grained discretisation (the offset tension and the offset heat duty) were obtained at the nominal point of operation as $V_{\text{offset}} = -0.004 \text{ V}$, $Q_{\text{offset}} = 3232 \text{ W}$.

In this way the flowsheet could be routinely solved simultaneously with all constraints enforced. If the rigorous model for the fuel-cell stack was used the flowsheet could only be

solved sequentially - a very time-consuming process for configuration B with its five recycles to converge.

4. Results and discussion

The key results, obtained by taking all the operational constraints into account, are summarised in Table 1.

These results are encouraging, indicating that it is feasible to feed the Molten Carbonate Fuel Cell–Gas Turbine energy production system with syngas derived from an IGCC.

The efficiency of a coal-fired IGCC is known to be 7% to 8% lower than that of a natural-gas-fired IGCC/IGFC. Consistent with these observations, the overall electrical and thermal efficiencies are lower than normal for MCFC-GT systems running on gaseous hydrocarbon fuels. This can be ascribed to the large amount of water steam generated for internal consumption and to the lack of integration between the endothermal reforming reactions and the exothermal effect due to the combustion of the unreacted syngas in the fuel cell (28%).

The water condensation and recovery for configuration B required careful verification. The dew point of the anodic outlet at about 350 kPa is 393 K, and closing the water loop involves condensing about 86% of this water, reducing its molar fraction from 56% to 15% and the dew point to 356 K; this is also the lowest thermal level of waste-heat output from this process, which still compares favourably with condensation boilers, where we have 323 - 333 K.

The water condensation and recovery in configuration B is a challenge in terms of heat integration, because it is desirable to match the heat duty (103 kW) required to bring the inlet-feed water from the liquid state at 288 K to the superheated vapour state at 350 kPa and 573 K partially using the heat load for the condensation (169 kW). The required

heating duty can be broken down as follows: 17% for heating in the liquid phase, 72% for evaporation (at 412 K) and 11% for superheating in the gas phase. The available cooling duty from the condensation, on the other hand, is managed as 27% (45 kW) sensible heat in the gas phase (from 903 K), the rest (125 kW) being latent heat for the partial condensation (393 – 356 K).

The temperature levels clearly make direct recovery impossible: only a part of the cooling duty of the condenser can be used for heat recovery from the incondensable stream (40 kW) and the rest has to be discharged in the form of waste heat for cogeneration (129 kW from 700 to 356 K).

Thanks to the simplification of the correctly-sized GTS, which requires no burner, no recuperator and no compressed air bypass, the number of active components at steady state is the same for the two configurations, although the turbine recuperator and burner would still be required for start-up even in configuration B.

The proposed modifications to configuration B should be validated and confirmed in terms of microturbine operability, heat losses and side effects due to the cooling of the anodic offgas, the cost and impact of the maintenance of the required additional equipment, and the management of impurities in the recovered water.

6. Conclusions

An MCFC-GT power plant optimised for use as a pilot-scale unit attached to the IGCC plant of ISAB Energy Srl in Priolo Gargallo (Italy) has been proposed. The configuration is robust and flexible with a 41% safety margin in cell current density, 3% in electrochemical fuel conversion, 14% in operating pressure and 33% in air flow.

The electrical yield was increased from 32 to 43% thanks to an optimally sized microturbine. The thermal + electrical yield was increased from 65 to 88% thanks to the

water condensation and recovery.

The water recovery also eliminated the need for a continuous demineralised-water feed, while avoiding a waste-water stream. The potential internal heat recovery was exploited while leaving safe margins in terms of temperature approaches, and keeping the thermal level of the cogenerative heat at a reasonable level.

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Figures

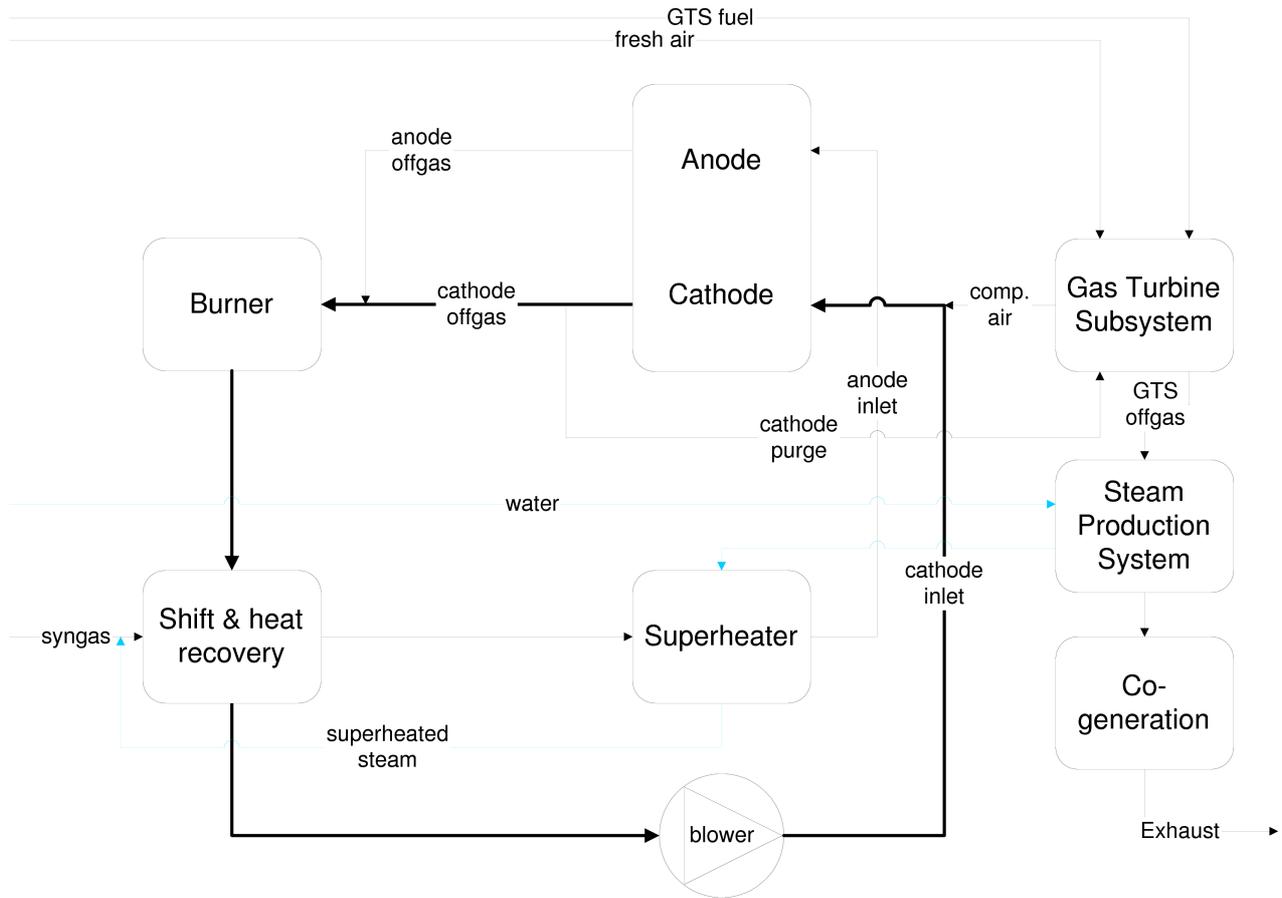


Figure 1 – Block Diagram of proposed MCFC-GT configuration A

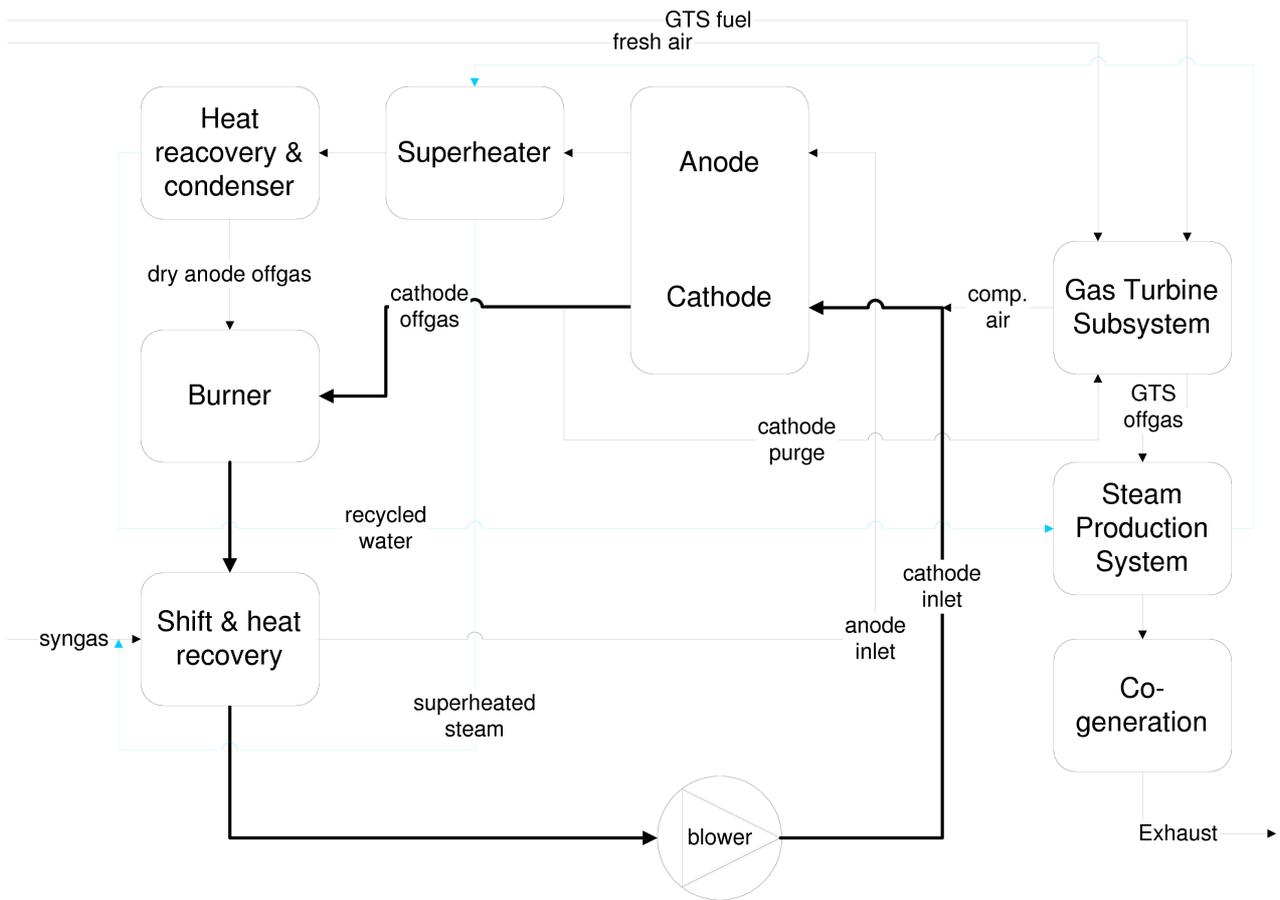


Figure 2 – Block Diagram of proposed MCFC-GT configuration B

Tables

Table 1 Summary of key inputs and results

Item	Conf. A	Conf. B	Units of measurements
Number of stacks/vessel	1	1	-
Number of cells /stack	200	200	-
Operating pressure	350	350	kPa
Syngas feed	101	101	Nm ³ /h
Auxiliary natural gas feed	16	0	Nm ³ /h
Fresh air feed	2100	726	Nm ³ /h
Water feed	124	0	kg/h
FC electrical power	125	125	kW
Current density	1100	1100	A/m ²
Fuel conversion in FC	72 %	72 %	CO+H ₂ basis
Nominal GT electrical power	100	30	kW
Actual GT electrical power output	37	15	kW
Electrical efficiency	33 %	43 %	-
Cogeneration process-side thermal level	363	356	K
Electrical + thermal efficiency	65 %	88 %	-