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Low-carbon hydrogen and electricity co-production with flexible "Powdrogen" plants

Alessandro de Cataldo[a], Marco Astolfi[a], Paolo Chiesa[a], Stefano Campanari[a], Emanuele Martelli[a], Paolo Silva[a], Stefano Bedogni[b], Luca Ottolina[b], Marco Tappani[c], Luca Rofi[d], Matteo C. Romano[a,]*

[a]Politecnico di Milano, Department of Energy, Via Lambruschini 4, 20156 Milan, Italy
[b]Edison Spa, Foro Buonaparte 31, 20121 Milan, Italy
[c]Ansaldo Energia SpA, Via Nicola Lorenzi 8, 16152 Genoa, Italy
[d]Ansaldo GreenTech Spa, Via Nicola Lorenzi 8, 16152 Genoa, Italy

Abstract

Low carbon hydrogen and dispatchable low-emission electricity are fundamental pillars of the future decarbonized energy system. This study aims to investigate the potential of natural gas based "Powdrogen" plants to produce blue hydrogen and decarbonized electric power, conceived to operate flexibly depending on the electricity price. The combination of hydrogen production and power generation in the same plant allows increasing the capacity factor of the capital-intensive steam methane reforming and CO_2 separation units, leading to better economic indicators (higher IRR, lower cost of electricity) than a power plant with CO_2 capture operating as load-following plant. In this paper, we consider plants based on fired tubular reforming (FTR) and auto-thermal reforming (ATR) technologies with pre-combustion CO_2 capture with MDEA process, designed to achieve very high CO_2 capture efficiency. The power island is based on a combined cycle with H_2-fired gas turbine and a triple pressure reheat heat recovery steam generator (HRSG). The plant considers different operating modes: hydrogen mode (reformer runs at full load with hydrogen export and combined cycle switched off), power mode (reformer runs at full load with all hydrogen burned in the combined cycle), polygeneration mode (reformer runs at full load with combined cycle at minimum load and exported hydrogen). An economic analysis is carried out on the best alternatives suggesting that each technology can be viable under different economic frameworks.

Keywords: Blue hydrogen, Combined cycle, Reforming, Flexibility.

1. Introduction

Securing global net zero greenhouse gas emissions by mid-century and keeping global temperature increase within 1.5 degrees is one of the targets of the recent COP 26 agreement in Glasgow 2021 [1], that will require a transition to decarbonized global economy in the next 30 years and a 45% cut in carbon dioxide emissions in the next 10 years [1], [2].

* Corresponding author. Tel.: +39-02-2399.3846, *E-mail address:* matteo.romano@polimi.it

Nomenclature

ASU	Air separation unit
ATR	Auto-thermal reformer
CAC	CO_2 avoidance cost
CCS	Carbon capture and storage
CCR	Carbon capture ratio
COE	Cost of electricity
COH	Cost of hydrogen
FTR	Fired tubular reformer
GT	Gas turbine
HPT/IPT/LPT	High/Intermediate/Low pressure turbine
HRSG	Heat recovery steam generator
HT/LT	High temperature/Low temperature
IC	Intercooled
IRR	Internal rate of return
MDEA	Methyl diethanolamine
NG	Natural gas
S/C	Steam to carbon ratio
SC	Steam cycle
SMR	Steam methane reforming
TIT	Turbine inlet temperature
TOT	Turbine outlet temperature
WGS	Water gas shift

The switch from coal to natural gas power generation is contributing in the decarbonization of the energy sector in the short term [3], with gas-fired power plants that are expected to play a fundamental role in next years to provide balancing services to electric grids strongly penetrated by non-programmable renewable energy sources [4].To further reduce CO_2 emissions from fossil fuel power plants, Carbon Capture and Storage (CCS) and low carbon hydrogen technologies [5] should also be deployed. However, the application of CCS in power plants working in the mid-merit market would cause a significant increase of the cost of electricity due to the high capital intensity of CCS and the low-capacity factor [6]. Also, while green hydrogen produced by electrolysis from renewable energies should be preferred in the long-term due to lower emissions [7], blue hydrogen (i.e. hydrogen from steam reforming of natural gas with CCS) can support the initiation of a low carbon hydrogen market [8], contributing to the decarbonization of the transport, the industrial and the power sectors [9].

The purpose of this study is to investigate the potential of new "Powdrogen" Polygeneration plants to produce blue hydrogen and decarbonized dispatchable power with high CO_2 capture efficiency, unlocking the possibility of reaching high-capacity factors for the CCS plant, with economic advantages compared to CCS technologies for separated power and hydrogen generation.

FTR- and ATR-based Powdrogen plants were analyzed by the same authors in [10], focusing on different plant configurations with different integration levels. The ATR-based plant showed greater economic feasibility when operated in power production while FTR-based showed greater economic viability when operated for hydrogen production. This work builds on the aforementioned paper by analyzing and proposing process modifications and component improvements, aiming at increasing the CO_2 capture efficiency beyond 90%.

2. Plant description

Figure 1 shows the generic block diagrams of the Powdrogen plants, consisting of the following main sections:

- Chemical island: after desulphurization, natural gas is converted into a H_2- and CO_2-rich syngas through steam reforming, based on either fired tubular reforming (FTR) or O_2-blown autothermal reforming (ATR), and two-stage Water Gas Shift (WGS) reactors. In order to limit the CO_2 emissions, the FTR furnace adopts H_2 burners that combust PSA off-gas and H_2-rich syngas after CO_2 separation.
- CO_2 separation: low-carbon H_2-rich fuel is obtained after CO_2 separation from syngas by chemical absorption with methyl diethanolamine (MDEA). The separated carbon dioxide is dehydrated and compressed to 110 bar and 28°C [11].
- Hydrogen purification: a conventional Pressure Swing Adsorption (PSA) unit allows to obtain high purity hydrogen, releasing low pressure (1.3 bar) off-gas stream used in the FTR burners or in the ATR off-gas boiler.
- Steam cycle: heat is recovered from the syngas cooling section and from the exhausts cooling section to provide the necessary steam for different uses: (i) steam reforming, (ii) power generation in a steam cycle and (iii) solvent regeneration in the reboiler of the MDEA section. A dedicated steam cycle recovering heat form the chemical island has been preferred compared to a single integrated steam cycle for both the chemical island and the gas turbine (GT) flue gas heat recovery. According to the findings from our previous study [10], a non-integrated steam cycle avoids overdesign and consequent part load penalization of the steam turbine, leading to higher overall electric efficiency and higher plant turn-down rate.
- Combined Cycle: a H-class gas turbine with nominal power output of 536 MW_e and combined cycle efficiency of around 63% (on natural gas firing) has been selected. The main assumption considers the gas turbine to be able to burn high hydrogen (>90% vol.) fuel in a premixed combustor by reducing the turbine inlet temperature and by slightly increasing the pressure ratio without any significant change in the design of the turbomachines compared to the corresponding natural gas fired conditions. The gas turbine is coupled with a triple-pressure and reheat steam cycle. The gas turbine size determines the size of the chemical island, which is sized to match the GT fuel input.

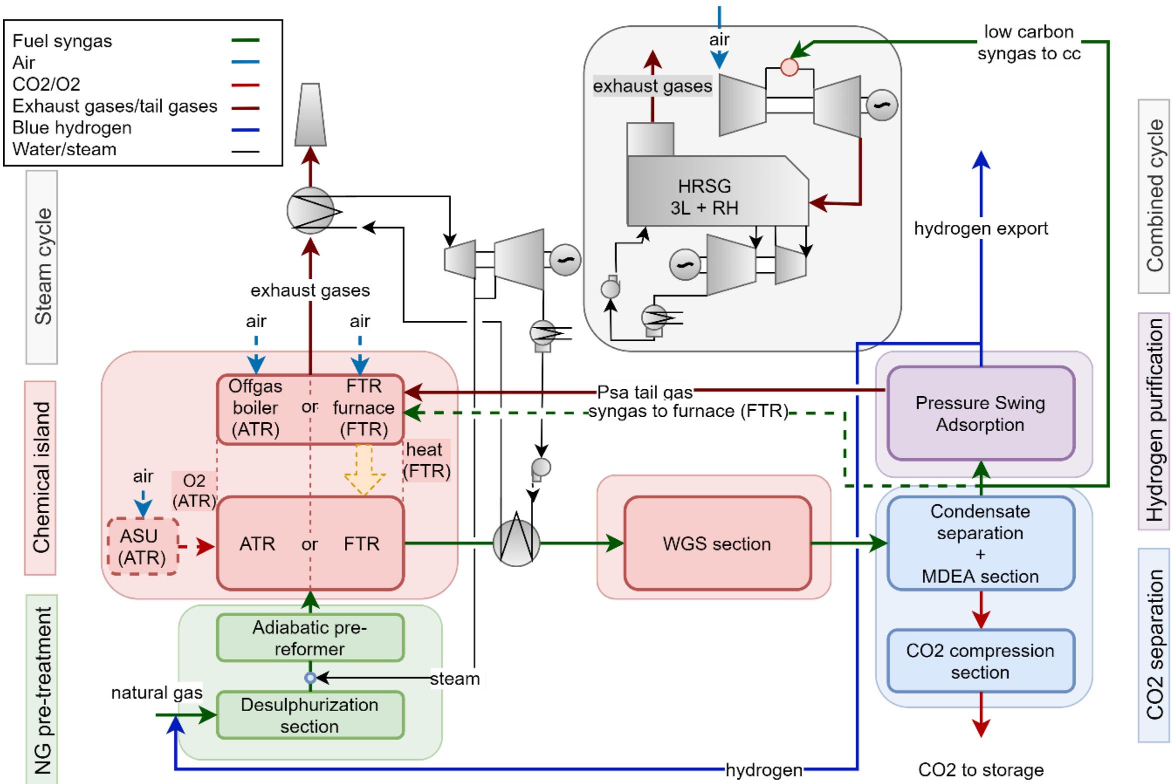

Figure 1 – Block flow diagram of a "Powdrogen" plant

2.1. Selected plants

This study compares three different Powdrogen plants with process parameters summarized in Table 1. The baseline FTR adopts conventional technologies and operating parameters, often assumed in the scientific literature. The achievable CO_2 capture efficiency in this case is limited by CH_4 conversion in the reformer, CO conversion in the WGS and CO_2 separation efficiency.

An improved FTR-based process (FTR-Plus) is also assessed, featuring improved design to increase the CO_2 capture efficiency, namely: (i) higher reformer exit temperature (950°C vs. 890°C) to improve methane conversion; (ii) cooled LT-WGS, with fixed outlet temperature of 200°C and (iii) increased CO_2 separation efficiency of the MDEA section (99%, as in state of the art ammonia production plants [12] vs. 95%); (iv) improved H_2 recovery in the PSA unit (95% vs. 89%).

The third case consists of an ATR-based plant with conventional reforming temperature and S/C, adiabatic WGS reactors and improved performance of gas treatment section, 99% CO_2 capture efficiency and 95% of H_2 recovery in the PSA unit as in FTR-plus process.

Table 1: Main plant assumptions

	FTR	FTR-Plus	ATR
Reforming temperature, °C	890	950	1050
Reforming pressure, bar	32.7	32.7	32.7
Steam to carbon ratio	3.4	3.4	1.5
Pre-reforming inlet temperature, °C	490	490	490
HT-WGS inlet temperature, °C	340	340	320
LT-WGS outlet temperature, °C	220	200[a]	250
CO_2 separation efficiency	95%	99%	99%
PSA H_2 recovery efficiency	89%	95%	95%

[a] *cooled reactor for the FTR Plus case.*

2.2. Operating modes

To assess the operational flexibility of the Powdrogen plant the following operating modes have been considered at both nominal and partial load of the chemical island:

- Hydrogen mode: the plant produces hydrogen as main output, operating the chemical island section at full load. The gas turbine is off. This is the nominal operating mode for the Powdrogen plant, that defines the design specifications of the process units, of the heat exchangers in the chemical island and of the chemical island steam cycle.
- Power mode: the chemical island works at full load and all the H_2-rich syngas produced is burned in the gas turbine. The only output from the plant is electricity since no hydrogen is exported. For this reason, the PSA is bypassed in power mode.
- Polygeneration mode: the plant operates producing both hydrogen and electricity. The chemical island operates at full load, part of the syngas produced is burned in the combined cycle which works at minimum load and the remaining syngas is sent to the PSA for co-production of high purity hydrogen.

3. Methods

Aspen Plus process simulation software was used to simulate the chemical island of all plants. The thermodynamic model used to simulate the system is the Non-Random Two Liquids model. All chemical reactors are calculated at chemical equilibrium, considering CH_4 as an inert in the WGS reactor. The H_2-fired gas turbine has been modelled with in-house GS code [13] with the cooled gas turbine model [14], [15].

3.1. Off-design model

When switching between the different operating modes and loads, equipment operates in off-design. For heat exchangers in the chemical island, the surface area is designed on the hydrogen operating mode. The off-design operating modes are calculated by assuming that the heat transfer coefficients are function of the fluid mass flow rates according to Equation (1). The overall heat transfer coefficient is then derived by Equation (2), with the assumption that the conductive resistance of the heat exchanger tubes is negligible.

$$h_{off} = h_{des} \cdot \left(\frac{\dot{m}_{off}}{\dot{m}_{des}}\right)^{0.8} \tag{1}$$

$$U = \left(\frac{1}{h_{HOT}} + \frac{1}{h_{COLD}}\right)^{-1} \left[\frac{W}{m^2 K}\right] \tag{2}$$

The chemical island steam cycle operates with constant evaporation pressure, to minimize the variation of temperature at the inlet of the WGS reactors. Throttling admission valves are used to control the high-pressure and intermediate-pressure steam turbines. The HP turbine operates with a fixed outlet pressure, as steam is extracted at fixed pressure to be mixed with natural gas before the reforming process. The condensers are simulated by assuming constant cooling water flow rate and temperature, leading to a condensation pressure reduction at partial loads. The expansion isentropic efficiency is calculated with routines to simulate off-design conditions [16], [17]. The chemical island can be operated at reduced load, assuming a maximum turn-down rate of 50% (e.g. 50% of NG input to the reformer [18]). The main assumptions for off-design operation are that the PSA, the MDEA section, the ASU and all the reactors are operated in the same performance and specific energy consumption as in nominal operation. More specifically: (i) H_2 recovery efficiency of the PSA, (ii) CO_2 separation efficiency and specific heat duty of the MDEA process, (iii) specific electric consumption per unit of O_2 produced in the ASU, (iv) chemical equilibrium composition at the exit of the reactors and (v) flue gas temperature at the reformer furnace outlet assumed unchanged in off-design operations. Referring to the three considered operating modes, the only difference in operation is experienced by the PSA unit that is switched off in power mode and works at reduced load in polygeneration mode.

4. Technical results

The following key performance indexes are calculated from the mass and energy balances (Table 2).

- The hydrogen production efficiency, that is computed as the ratio between the hydrogen energy output (LHV basis) over the natural gas input, according to Equation (3).
- The equivalent H_2 production efficiency (Equation (4)) considers the "equivalent" natural gas input, including the credits from electric power export $\dot{P}_{el}$, accounted by assuming a reference combined cycle efficiency of 63%.
- The net electric efficiency (Equation (5)) is the ratio between the net electric output over the heating value of the natural gas input.
- The carbon capture ratio (CCR) is defined as the molar ratio between the captured carbon (as CO_2) and the carbon entering with natural gas (Equation (6)).
- The specific CO_2 emission can be calculated referring to hydrogen (Equation (7)) or power (Equation (8)) output, depending on the operating mode. The specific emission considers the CO_2 mass flow rate directly emitted by the plant at the stack.
- The Specific Primary Energy Consumption for CO_2 Avoided (SPECCA) [19] represents the energy consumption associated to a unit of avoided CO_2 emission. In Hydrogen mode (Equation (9)), it is defined as the ratio between the differences in specific equivalent fuel consumption ($1/\eta_{H2,eq}$) and equivalent CO_2 emission with reference to a Fired Tubular Reformer plant without CCS (i.e. $\eta_{H2,\mathrm{eq,ref}}$=79.7%, $E_{H2,\mathrm{eq,ref}}$=73.4 g_{CO2}/MJ_{H2}).In Power mode

(Equation (10)), it is defined as the ratio between the variations of heat rate ($3600/\eta_{el}$) and CO_2 emission with reference to a natural gas combined cycle without CCS ($\eta_{el,\mathrm{ref}}$=63%, $E_{el,\mathrm{ref}}$=325.6 $kgCO_2/MWh$).

Table 2: Key performance indexes

$$\eta_{H2} = \frac{\dot{m}_{H2} \cdot LHV_{H2}}{\dot{m}_{NG} \cdot LHV_{NG}} \quad (3)$$

$$\eta_{H2\_eq} = \frac{\dot{m}_{H2} \cdot LHV_{H2}}{\dot{m}_{NG} \cdot LHV_{NG} - \frac{\dot{P}_{el}}{\eta_{el,ref,NGCC}}} \quad (4)$$

$$\eta_{el} = \frac{\dot{P}_{el}}{\dot{m}_{NG} \cdot LHV_{NG}} \quad (5)$$

$$CCR = \frac{\dot{n}_{C,stored}}{\dot{n}_{C,GN}} \quad (6)$$

$$E_{H2} = \frac{\dot{m}_{CO2\_emitted}}{\dot{m}_{H2} \cdot LHV_{H2}} \left[\frac{g_{CO2}}{MJ_{H2}}\right] \quad (7)$$

$$E_{El} = \frac{\dot{m}_{CO2\_emitted}}{\dot{P}_{el}} \left[\frac{kg_{CO2}}{MWh_{el}}\right] \quad (8)$$

$$SPECCA = \frac{\frac{1}{\eta_{H2,eq}} - \frac{1}{\eta_{H2,eq,ref}}}{E_{H2,ref} - E_{H2}} \left[\frac{MJ_{LHV}}{kg_{CO2}}\right] \quad (9)$$

$$SPECCA = \frac{\frac{3600}{\eta_{el}} - \frac{3600}{\eta_{el,ref}}}{E_{el,ref} - E_{el}} \left[\frac{MJ_{LHV}}{kg_{CO2}}\right] \quad (10)$$

4.1. Results

Table 3 shows the performance of the three plants in hydrogen mode. The reference case for the fired tubular reformer (FTR) has the highest hydrogen production efficiency (74.59%) and the lowest carbon capture ratio (78.88%). In the FTR-Plus case, hydrogen production efficiency reduces to 71.33%, as more hydrogen is burned in the FTR furnace to supply the increased heat demand. On the other hand, the steam flowrate generated by heat recovery is greater and this results in a higher net electric power output, despite the increase in CO_2 compressor consumption. The CCR increases to 90.52%, reducing the specific emissions from 16.16 g_{CO2}/MJ_{H2} to 7.58 g_{CO2}/MJ_{H2} (or from 1.94 kg_{CO2}/kg_{H2} to 0.91 kg_{CO2}/kg_{H2}). The ATR has a lower hydrogen production efficiency than baseline FTR but higher than the FTR-Plus (73.47%) and the highest carbon capture ratio (94.15%). The equivalent hydrogen production efficiencies are from 1.6 to 2.4 percentage points higher than the corresponding hydrogen efficiencies. The baseline FTR and the ATR result in similar SPECCA, slightly below 1 MJ/kg_{CO2}, while it increases to 1.5 MJ/kg_{CO2} in the FTR-Plus plant, indicating a higher marginal energy CO_2 avoidance cost.

Table 3: Powdrogen plants performance data in hydrogen mode

	FTR	FTR-Plus	ATR
NG thermal LHV input, MW	1635	1710	1419
Hydrogen LHV output, MW	1220	1220	1043
Net electric output, MW	22.31	34.84	25.95
Hydrogen production efficiency, %	74.59	71.33	73.47
Equivalent hydrogen production efficiency, %	76.24	73.71	75.67
Carbon capture ratio, %	78.88	90.52	94.15
Specific emission g_{CO2}/MJ_{H2}	16.16	7.58	4.54
Specific emission kg_{CO2}/kg_{H2}	1.94	0.91	0.54
SPECCA, MJ/kg_{CO2}	0.98	1.54	0.96

Table 4 shows the performances of the Powdrogen plant when operating in power mode. The ATR shows the highest net electric efficiency (50.97%) 2-3% points higher than FTR and FTR-Plus. This result is due to the fact that, in hydrogen mode, the FTR configuration makes better use of the chemical energy of the PSA off-gas stream, which is burned in the FTR burners. In contrast, in ATR-based plants, the PSA off-gas is burned in a boiler when operating in hydrogen mode (thus involving higher exergy losses). In power mode, all the syngas from the ATR chemical island is supplied to the combined cycle. Conversely, the FTR requires fuel in the reformer furnace, leading to lower efficiency and higher natural gas consumption (+20%) to produce the H_2-rich fuel for the gas turbine of given size. The FTR-Plus results in the lowest net electric efficiency (47.36%). On the other hand, the FTR-Plus achieves less than half the emissions of the baseline FTR (40.9 vs. 91.1 kg_{CO2}/MWh_{el}), though still higher than the ATR plant (23.4 kg_{CO2}/MWh_{el}). The ATR-based plant shows the lowest SPECCA (4.46 vs 6.63 MJ/kg_{CO2}). The study will focus on the FTR-plus and the ATR given the high carbon capture ratio achieved.

Table 4: Powdrogen plants performance data in power mode

	FTR	FTR-Plus	ATR
NG thermal LHV input, MW	1635	1710	1419
Net power output, MW	798.1	810.0	723.4
Net electric efficiency, %	48.80	47.36	50.97
Carbon capture ratio, %	78.51	90.58	94.19
Specific emission kg_{CO2}/MWh_{el}	91.10	40.89	23.38
SPECCA, MJ/kg_{CO2}	7.09	6.63	4.46

4.2. Operating maps

The operating maps of the FTR-Plus and ATR plants are shown in Figure 2. The maps show the hydrogen and electricity production regions in which the plant can operate. The vertices of each region represent one of the operating points. The left side of the chart shows the hydrogen and minimum hydrogen modes (labeled “H” and “MH”). The straight lines represent the margins of the possible operating region, where the plant can tune the H_2 and power export between the maximum and the minimum load of the reformer. Point “E” identifies the power mode, where the chemical island and the combined cycle run at full load and hydrogen is not exported from the plant. At the Polygeneration point “P”, the reformer works at nominal load, while the GT operates at minimum load (30% of GT power output); the plant exports 57.3% (FTR-Plus) or 56.7% (ATR) of the nominal hydrogen production. The combined cycle also runs at reduced load in points “MP” and “ME”; in the former case the reformer is operated at reduced load with limited hydrogen output, in the latter the combined cycle is operated at part load receiving all the syngas produced by the reformer.

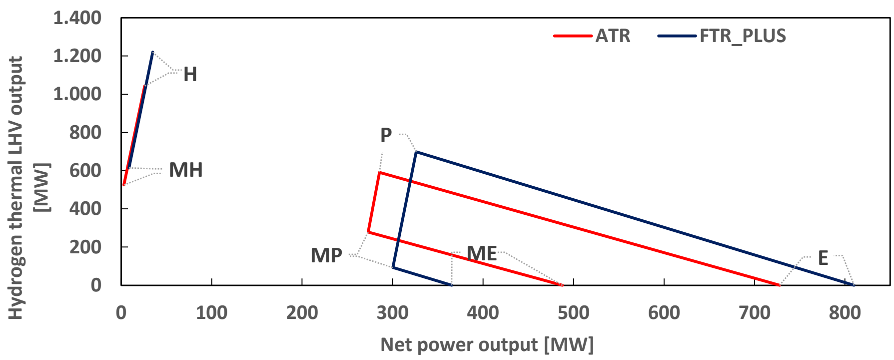

Figure 2 – Operating maps for ATR and FTR-Plus plants

5. Economic analysis

The economic analysis is performed following the method from [20]. The total plant cost for each section is calculated from [21], updated with CEPCI (Chemical Engineering Plant Cost Index) and scaled to the proper size. The breakdown of the total capital cost is shown in Table 5. Given the large capacity of the chemical plant (420'000 Nm^3/h) the FTR-Plus is made of two trains [22].

Table 5: Breakdown of the total capital requirements for ATR and FTR-Plus plants

	ATR	FTR-Plus
Total plant cost M€	1282	1220
• Air separation unit, %	22.5	-
• Syngas generation, %	7.3	19.8
• Hydrogen purification, %	3.4	4.0
• Steam turbine and Generator, %	4.4	4.3
• Syngas cleanup, %	3.8	5.7
• CO_2 compression and drying, %	6.1	7.6
• Feedwater and Miscellaneous BOP Systems, %	12.0	16.0
• Combined cycle, %	40.5	42.6
Total capital requirements, M€	1650	1575

The fixed operating costs consist in:

- Direct labor (considering an average cost of 60 k€/y per person).
- Administrative and Support Labor (30% of the direct labor and the maintenance labor cost).
- Annual maintenance cost (1.5% of Total plant cost, maintenance labor is 40% of the overall maintenance cost).

Table 6 shows the main consumables and the associated cost while Table 7 shows the main financial parameters.

The study is based on Discounted Cash Flow analysis, depreciation was not considered since the results are reported on the Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) basis.

Table 6: Consumables cost

Variable costs	Unit	Cost
Natural gas	€/GJ (LHV)	9
Raw water	€/m^3	0.20
Electricity selling price	€/MWh	60
CO_2 transport and storage	€/t_{CO2} stored	10
CO_2 emission cost	€/t_{CO2} emitted	100

Table 7: Main financial assumptions

Euro valued in year	2020	Capacity factor	86% (7500 equivalent hours)
Construction period	3 years	Finance	100% Financial leverage
Capital expenditure curve	20/45/35% (1st ,2nd,3rd year)	Discount rate	8%
Interest during construction	8%	Inflation	2%
Plant lifetime	25 years	Owner's cost	7%

The Cost of Hydrogen (COH) and the Cost of Electricity (COE) were evaluated as the break-even sales prices for the two products. The first index was evaluated assuming to operate the plant at 100% of the equivalent hours in hydrogen mode, while the second considers operation only in power mode. The cost breakdowns are shown in Figure 3 for both ATR and FTR-Plus cases. For both indexes the highest share is due to natural gas consumption, followed by the capital expenditures. The ATR results in a slightly higher COH (2.33 vs 2.27 €/kg) and a lower COE (103.1 vs 105.3 €/MWh).

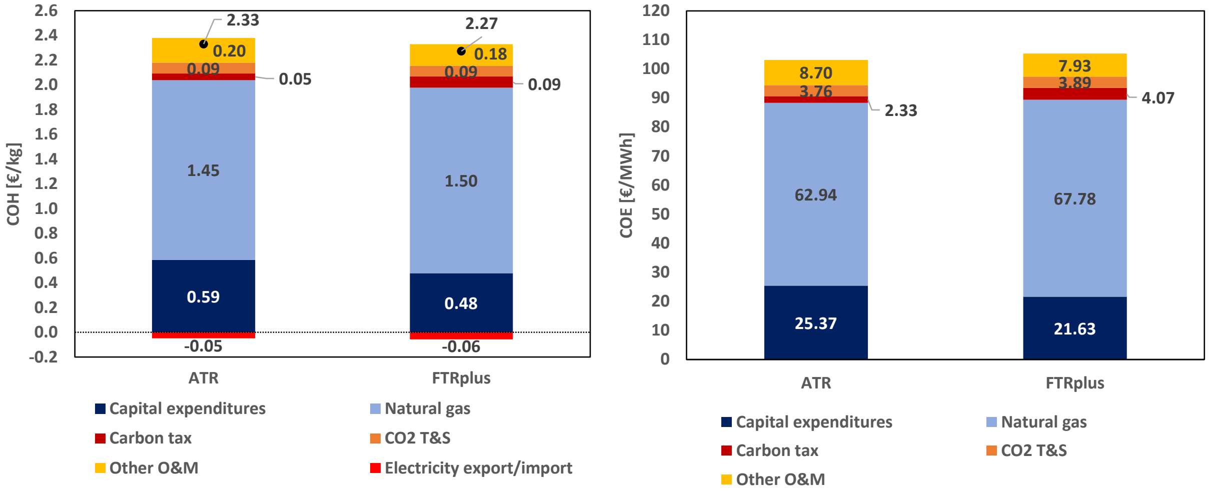

Figure 3 – Cost breakdown of COH (left) COE (right) for ATR and FTR-Plus plant

The CO_2 avoidance cost (CAC) expressed in €/t_{CO2} is shown in Table 8 with reference to (i) a FTR reformer of same size of the FTR-Plus and no CCS and (ii) a combined cycle of same size without CCS. The CAC is lower for the ATR with respect to the FTR-Plus in power mode (103.6 vs 111.7 €/t_{CO2}) but higher in hydrogen mode (80.4 vs 71.9 €/t_{CO2}).

Table 8: Main findings of the analysis

	Unit	FTR-reference	CC-reference	ATR	FTR-Plus
Specific emission (power mode)	kg_{CO2}/MWh_{el}	-	325.6	23.4	40.9
Specific emission (hydrogen mode)	kg_{CO2}/kg_{H2}	8.98	-	0.54	0.91
COH (neglecting carbon emission cost)	€/MWh_{el}	-	69.4	2.28	2.18
COE (neglecting carbon emission cost)	€/kg_{H2}	1.60	-	100.7	101.2
CAC (power mode/hydrogen mode)	€/t_{CO2}	-	-	103.6 / 80.4	111.7 / 71.9

Figure 4 shows the iso-Internal Rate of Return (IRR) curves on an electricity and hydrogen price chart. Each line delimits the region of points where plant operation is profitable. To make the plant profitable (i.e. with IRR higher than 8%), average electricity and hydrogen selling prices should be above the corresponding line.

Three different shares of operating modes are considered, from a hydrogen-prevalent (75% hydrogen mode – 25% power mode) to a power-prevalent (25% hydrogen mode – 75% power mode) production mode, in order to understand the effect of real average operating modes throughout the year. The FTR-Plus plant shows higher competitiveness when operated mostly in hydrogen mode, while the ATR performs slightly better if the plant operates mainly in power mode.

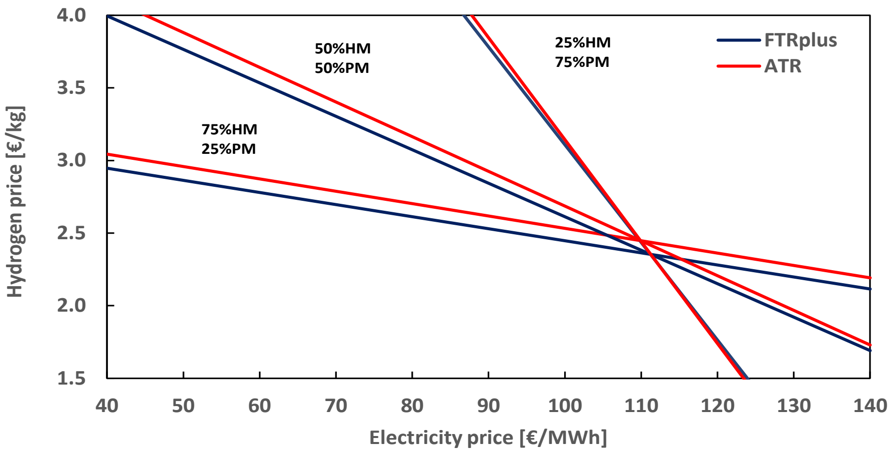

Figure 4 – Iso-IRR (IRR=8%) curves for ATR and FTR-Plus for three different operating regimes

6. Conclusion

This study focuses on "Powdrogen" plants capable of achieving superior carbon capture ratio in the production of low-carbon electricity and blue hydrogen from natural gas. The study considered hydrogen production plants based on FTR and ATR technologies connected to a combined cycle composed of a H-class gas turbine and a three-pressure and reheat recuperative steam cycle. Some improvements to the conventional FTR-based process were considered to increase the carbon capture ratio above 90% with pre-combustion CO_2 separation only. Carbon capture ratios of 90.5% and 94.1% were obtained for FTR-Plus and ATR cases respectively with hydrogen production efficiencies of 71.3% and 73.6%, respectively. From the economic point of view, the FTR-Plus plant shows a high competitiveness in hydrogen mode, the ATR-based plant has higher capital expenditure and is preferred when the system is operated mainly in power mode. The CO_2 avoidance cost for the system was assessed resulting in a value of 103.6 and 111.7 €/t_{CO2} in power mode and 80.4 and 71.9 €/t_{CO2} in hydrogen mode respectively for ATR and FTR-Plus.

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