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THE ROLE OF COMBINED CYCLE GAS TURBINES AS AN ENERGY STORAGE SOLUTION IN A HYDROGEN ECONOMY

Jose Garcia [a*], Rafael Guedez [a], Björn Laumert [a]

[a] KTH Royal Institute of Technology, SE-10044 Stockholm, Sweden

[*] Corresponding author: jagf@kth.se. Phone no. +46760693034

ABSTRACT

The global push towards achieving climate neutrality involves reducing carbon emissions in all sectors and incorporating more renewable energy into the power grid. Additionally, to reduce dependence on imported natural gas (NG) for thermal power plants, many European countries are exploring the development of a hydrogen economy, which can be produced through reforming NG or via electrolysis using renewable energy. Thus, one probable scenario is that hydrogen production and utilization will increase, particularly in Combined Cycle Gas Turbines (CCGTs) for electricity generation.

This study proposes a power-to-X-to-power (P2X2P) layout, which involves adding hydrogen generation and storage systems to existing CCGTs. Hydrogen is produced during low-price electricity periods and stored for injection into the gas turbine. The paper outlines the components proposed, optimal operational strategies, system sizing, and potential markets. The power system's performance is evaluated using technical, economic, and environmental indicators, with the goal of assessing the potential of P2X2P systems to offer a viable solution for energy storage and shifting, possibly reviving mothballed CCGTs.

The results show that, under current and previous fuel and electricity market conditions considered, and with the assumptions taken, the power plant layout proposed is not economically feasible. However, if the fuel prices and the daily electricity price fluctuation are increased, as forecasted by public and private organisations, these P2X2P systems are a promising solution for existing CCGTs and could play a significant role in achieving energy independence, reducing carbon emissions, and transitioning to renewable energy sources.

INTRODUCTION

As the global energy landscape undergoes a transformation in response to climate change, the transition to a H_2 economy has gained momentum. Green H_2, as a versatile and sustainable energy carrier, presents a promising alternative to conventional fossil fuels, particularly in the context of decarbonizing various sectors of the economy. In this study, we explore the potential of CCGTs as an energy storage solution in a H_2 economy, with a focus on their role as a power-to-X-to-power (P2X2P) system.

The main hypothesis of this paper is that in the future, H_2 will become a widespread fuel, paving the way for a hydrogen-based economy. Europe, with its extensive deployment of CCGT plants, stands out as an ideal candidate for examining how CCGTs can participate in such scenario. Currently, these CCGT plants utilize NG as their primary fuel source. However, they have the potential to be retrofitted and upgraded to also use H_2 as a fuel, effectively transforming them into P2X2P systems (Bogdanov, o.a., 2019).

A key component of this transition is the strategic utilization of excess electricity generated from renewable energy sources, such as solar and wind power. During periods of high renewable energy production, the electricity supply often exceeds the demand, leading to low electricity prices. This paper investigates the concept of harnessing this surplus, low-cost electricity to produce H_2 via electrolysis, which can then be stored for later use in the upgraded CCGT plants (Fasihi, o.a., 2016).

While numerous studies have explored the potential of CCGT plants using H_2 as a fuel (YEC-ETN, 2022), this research focuses on the in-situ production of H_2 using on-site electrolysers and storage systems. This approach offers several advantages, such as increased operational flexibility, reduced dependence on external H_2 supplies, and improved responsiveness to grid fluctuations (Staffell, o.a., 2019).

The conversion of excess electricity into H_2 enables more options for energy storage, addressing the challenges of intermittency and fluctuations in renewable energy generation. Moreover, the integration of H_2 into the existing CCGT infrastructure facilitates a transition to a low-carbon energy system, while capitalizing on the benefits of H_2 as a clean and abundant energy carrier. The P2X2P system not only enables storage of potential surplus electricity in the grid but also serves as a flexible and dispatchable power source, capable of meeting the varying demands of the electrical grid.

In this study, we evaluate various scenarios to account for different factors that can impact the feasibility and performance of P2X2P systems. These factors include diverse NG prices, varying levels of CO_2 tax, distinct electricity production profiles, and the characteristics of different electricity markets with contrasting daily price fluctuations. By examining these scenarios, we aim to provide a comprehensive understanding of the potential benefits and challenges of implementing P2X2P systems under various market-driven boundary conditions.

This paper aims to provide a comprehensive analysis of the role of CCGT plants as an energy storage solution within a H_2 economy. To achieve this, we delve into the technical aspects of retrofitting and upgrading CCGT plants to accommodate H_2 (production and utilisation) and examine the economic feasibility of such a transition. Through this investigation, we aspire to shed light on the prospects of CCGT plants playing a vital role in the emerging H_2 economy, while simultaneously supporting the integration of renewable energy sources and driving the global transition towards a low-carbon energy system.

NOMENCLATURE

Abbreviations

CCGT	Combined cycle gas turbine
CCGT	Combustion Chamber
Comp	Compressor
DAM	Day ahead market
EHO	Equivalent operating hours
FCF	Free cash flow
GT	Gas turbine
HRSG	Heat recovery steam generator
MILP	Mixed integer linear program
NG	Natural gas
NPV	Net present value
O&M	Operation and maintenance
P2X2P	Power to X to power
PEM	polymer electrolyte membrane
ST	Steam turbine

Symbols

C	Cost [M€]
d	Deviation of original electricity price from average value
D	Deviation of modified electricity price from average value
E	Electric power [MW_{el}]
OP	Operational profit
Px	Power from/to component "x"
Q	Thermal power [MW_{th}]
R	Universal gas constant
$relC$	Relative maintenance cost
sPC	Specific cost
t	Time [h]
$volFact$	Volatility factor
V	Gas volume
Wx	Compression power [MW]
y	Year

Subscripts

Des	Design point
el	Electric
exh	Exhaust
fixM	Fixed maintenance
GT	Gas turbine
nom	Nominal
oper	Operation
SC	Steam cycle
SU	Start-up
varM	Variable maintenance

SYSTEM CONFIGURATION

The system configuration studied is shown in Figure 1. The first group of components, enclosed by the brown dashed lines, form a conventional CCGT fuelled by NG. Then, an electrolyser, a H_2 compression system, and a compressed H_2 storage are added. These components combined with the CCGT make for a P2X2P system, represented within the dashed blue lines. Finally, the power plant is connected to the electric grid, for which it can provide or receive electric power.

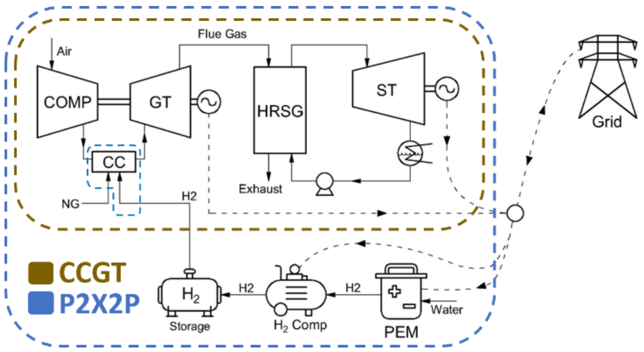


Figure 1. Studied P2X2P configuration.

Integrating the P2X2P components

In addition to the conventional CCGT, the layout studied incorporates supplementary equipment for H_2 production, storage, and utilization (within the blue dashed lines in Figure 1). The main components included are a polymer electrolyte membrane (PEM) electrolyser, a H_2 compressor, a H_2 storage system, as well as modifications to the GT's combustion chamber to enable for H_2 injection and substitution of NG. The electrolyser technology chosen for the layout is PEM because of its commercial maturity, its high conversion efficiency, and its ability to handle large load variations in small time periods (within seconds). In the models developed in this study, it is assumed that the electrolyser can operate at any point within 10 to 100% of its nominal capacity and, for simplification purposes, it is assumed that its operating pressure and temperature are fixed at 30 bar and 65 °C, respectively.

The size of the electrolyser in this layout is an open variable subjected to optimisation and was maintained within 10-390 MW_{el}, which is around 2.5 to 100% of the size of the CCGT. The H_2 compressor considered is a centrifugal multi-stage compressor; it receives the H_2 produced by the PEM at 30 bar and compresses it up to a maximum of 200 bar - or less, depending on the state of charge of the storage system. The compressor is sized such that it is able to compress the totality of the H_2 produced by the PEM at nominal conditions.

The H_2 produced is stored in the form of compressed gas at ambient temperature. To such end, several rigs of cylindrical vessels are used. The storage size is also a variable subjected to optimisation, and it is referred to in hours of H_2 production at nominal conditions. Thus, a 4 h storage system coupled to a 100 MW_{el} PEM electrolyser would contain nearly twice as much H_2 (mass, in Kg) as a 4 h storage coupled to a 50 MW_{el} PEM. The storage capacities studied were maintained within 4-20 h, always maintaining a daily character of the dispatch. Longer duration storages can also apply in these P2X2P systems but are not studied in this work.

The last equipment or modification in this configuration has to do with retrofitting the combustor chamber, as it must be adapted to burn H_2 as fuel instead of −or together with− natural gas. The modifications needed are highly dependent on the GT model considered and the maximum content of H_2 in the fuel mix. In this study, the CCGT is able to use a mix of NG and H_2, with maximum H_2 volumetric contents of 10, 30, and 100%, depending on the case considered. This means that a conventional GT would require different levels of intervention (the cost of said upgrade is accounted for and described in the system design section of this work). In this configuration, all the H_2 used by the CCGT is produced in situ, i.e. no additional H_2 is sourced for the power plant. Therefore, the fuel is described as a mix − instead of a complete switch to H_2− because on many occasions the H_2 stored will not be enough to cover a particular electric load required by the grid.

The electricity used by the electrolyser, and its BoP, can be supplied by the grid (during moments of no demand and low electricity prices) and by the CCGT itself. In this way, the grid can be seen as an electricity source during some hours (when producing and storing H_2), and as an electricity sink (when emptying the H_2 storage and running the CCGT). In both cases, charging and discharging, the electricity transferred in the connection point to/from the grid is limited by the CCGT capacity (392 MW_{el}).

METHODOLOGY

The following sections explain the scenarios considered in this study, and then the simulation process, which is followed in each of the scenarios and includes the design of the system, its operation control, and its techno-economic performance. The scenarios definition start with a "base case", which aims at capturing the conditions of the year 2022. In this "base case" we include two different scenarios defined by the intended role of the CCGT in the electric grid (Mid-merit or Peaker). The rest of the scenarios are derived from the base case and cover different possible conditions in the electricity and fuel markets.

Boundary conditions of the base case scenarios

The boundary conditions that identify the case study are defined by the local climate, electricity market, and fuel market. These conditions are sourced for a location near Lisbon, in Portugal, for which historical data from 2022 has been used.

The climate conditions include hourly values of ambient temperature and pressure, as they affect the CCGT's power output and efficiency. As for the electricity market, it is assumed that the power plant is connected to the national electric grid and participates only in the day-ahead-market (DAM). In more comprehensive business models, the power plant also provides additional ancillary services such as energy balance and frequency control, which depending on the operation strategy and market conditions, can represent up to 80% of the total revenues, as shown by (Vannoni, o.a., 2021); however, participation in these additional markets is outside of the scope of this study.

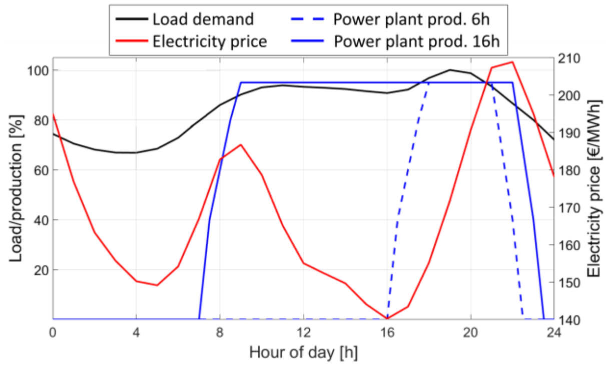


Figure 2. Production profile and electricity price

The interaction between the power plant and the grid is characterized by the load required and the electricity price. The load required refers to a specific pre-defined electric power that the power plant must inject in the grid at every hour. Two different electricity production profiles were considered (scenarios 1 and 2), "mid-merit power", and "peaking power", as shown in Figure 2. These two profiles consist of respectively 16 and 6 hours of power output at 95% of nominal capacity, every day. For the mid-merit (solid blue line), the production starts at 07:00 and ends at 23:00, aligning with the high load region of the average demand curve of Lisbon in 2022. For the peaking profile (dashed blue line), the production starts at 16:00 and ends at 22:00, covering the highest 6-hour load period of the day. The other 5% of the nominal capacity is left untapped or available and it is assumed that it is used to participate in other markets, although such participation is not quantified in this work. The electricity price − also shown in Figure 2 − at which the P2X2P system trades electricity to and from the grid, is set by historical hourly values in the DAM for the location studied.

Finally, the fuel market is characterized by the price of NG and the tax applied to CO_2 emissions. The average price of NG and CO_2 emissions in 2022 in Europe was 129.37 [€/MWh] and 81.48 [€/ton] respectively (Economics). Thus, the values 130 [€/MWh] and 80 [€/ton] were used in this work. It is pertinent to note that the electricity purchased from the grid − for H_2 production during periods of low-cost electricity − is presumed to be carbon-free. This is premised on the assumption that such electricity is derived from the excess generation from renewable energy sources.

Boundary conditions of additional scenarios – fuel market

In the scenarios 1 and 2, the fuel market is defined by a NG price and a CO_2 tax price based on average values of 2022, which was a particular year in the energy market, especially in Europe. Arguably, 2022's prices are noticeable higher than the prices experienced in years prior and in current conditions (first semester of 2023).

These prices are also lower than those forecasted for 20 years by several agencies. For those reasons, two more sets of scenarios are considered in this study.

In scenarios 3 and 4, we consider lower fuel prices. The NG price goes from 130 to 50 [€/MWh] and the CO_2 emissions cost goes from 80 to 40 [€/ton], which are values aligned with current markets. The difference between scenarios 3 and 4 is the electricity production profile used (Mid-merit or Peaker).

In scenarios 5 and 6, we consider higher fuel prices, in line with fuel price projections shown in (YEC-ETN, 2022) for the following 30 years. The NG price goes from 130 to 210 [€/MWh] and the CO_2 emissions cost goes from 80 to 120 [€/ton]. The difference between scenarios 5 and 6 is, again, the electricity production profile used.

Boundary conditions of additional scenarios – electricity market

One key feature of a P2X2P system is that it can have the same function of a storage plant, exploiting the price fluctuations in a dynamic market. Such is the case of the layout studied and the electricity market. This system is expected to thrive in electricity markets with higher price fluctuations, more specifically for this work, daily price fluctuations, given the daily dispatch character of growing renewable energy technologies like solar photovoltaic.

Figure 3 shows, in the black solid line, the electricity price of an average day (over the full year 2022) in Lisbon. The solid red line represents a more volatile electricity market. The electricity price in the latter has the same average price (black dashed line), but the higher and lower prices are amplified with respect to the original values. The price in this more volatile market was calculated with equation (1), where d is the difference between the original electricity price at any given moment and the average price, D is the difference between the modified electricity price and the average price, and $volFact$ is volatility factor, the variable used to increase the amplitude of the price. Different values of $volFact$ where explored and it was found that a value of 4 makes the low electricity prices go near zero, making the electricity price profile similar to that expected in a future with even higher shares of renewable energy sources in the grid. Thus, this value was used for the scenarios 7 to 12.

$$D = volFact \cdot d \tag{1}$$

The scenarios with higher electricity price fluctuation are scenarios 7 to 12, and they replicate scenarios 1 to 6 in terms of fuel prices. Table 1 summarizes the values considered in each scenario.

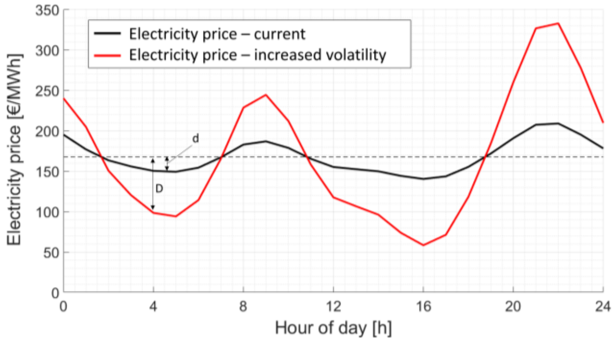


Figure 3. Electricity price and volatility

Table 1. Scenarios considered in the study.

Scenario	NG price [€/MWh]	CO_2 tax [€/ton]	Electricity load [hrs]	Elec. Price volatility [-]
1 2	130 medium	80 medium	16 6	Low
3 4	50 low	40 low	16 6	
5 6	210 high	120 high	16 6	
7 8	130 medium	80 medium	16 6	High
9 10	50 low	40 low	16 6	
11 12	210 high	120 high	16 6	

Simulation Process

A general description of the simulation process is presented next, as illustrated in Figure 4. More specific information about each of the steps is provided in the following subsections. Each simulation starts by defining the technical, operation, and economic inputs (step identified "1" in Figure 4). The first set of inputs is used for designing the system and its components (step "2"). For example, the electrolyser's H_2 production rate (Kg/h), and the H_2 compressor's capacity (Kg/h and kW), are calculated with, among others, the chosen electrolyser size (MW) and the operation pressures (both are inputs); the storage mass capacity (Kg) is calculated with its chosen time capacity (h) and the PEM's H_2 production rate, etc.

Then, the power plant design and its operation parameters are fed to the dispatch optimizer. This optimizer is a mixed integer linear program (MILP) that determines the best way to operate the system (step "3") given its technical constraints (e.g. minimum up/down times, maximum production ramp up/down), minimizing the operational costs incurred (e.g. fuel, variable maintenance), whilst maximizing the revenues (electricity sold in the DAM). As mentioned before, the power plant must meet the load demanded by the grid, then, around that main constraint, the power plant is free to choose when it is better to buy electricity from the grid and produce H_2 for later use. That is the MILP's function in the simulation process. The output of the optimizer is a half-hourly data set with the proposed operation strategy of each component (on/off/amount) for a full day of operation. That operation strategy is used by the thermodynamic model as the control logic. It is in the

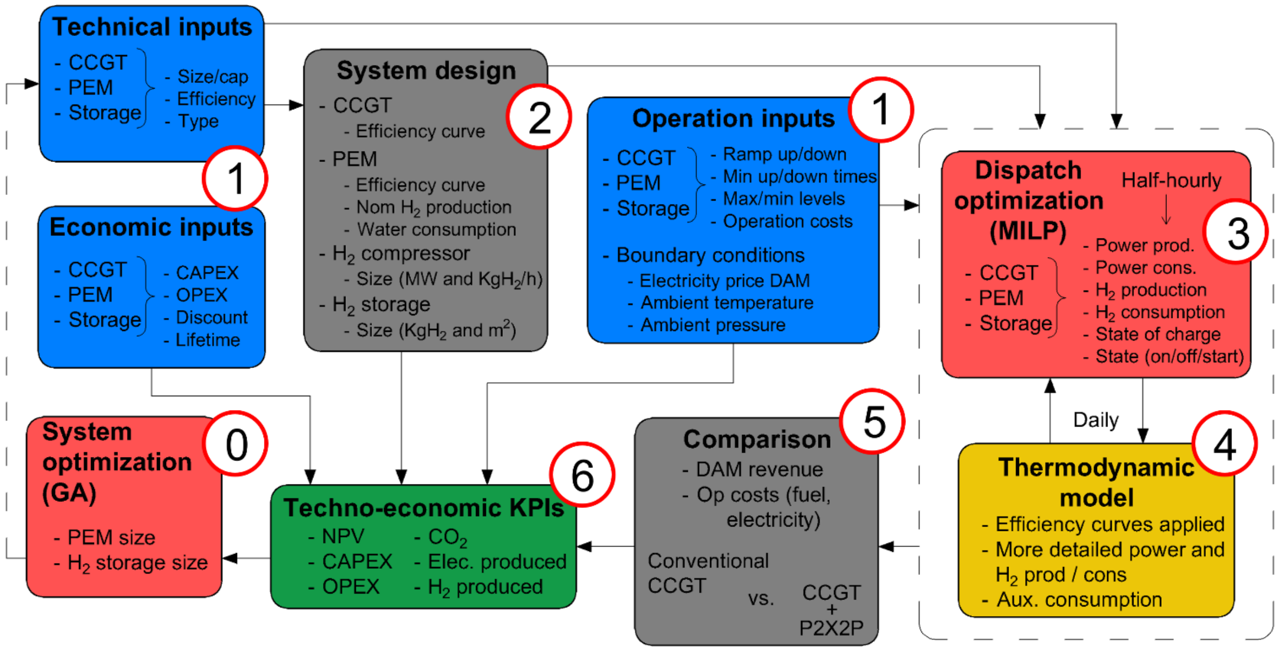


Figure 4. Simulation Process

thermodynamic model (step "4") where the final electricity and H_2 production and consumption are determined, considering part-load efficiencies and the effect of ambient conditions. In Figure 4 there is a two-way interaction between the processes 3 and 4. The reason is that for solving the day "d", the MILP requires information from the last hours of the day "d-1". This information (e.g. CCGT on/off status, H_2 content in the storage, etc.) is determined by the thermodynamic model in step 4. This cycle is repeated for every day of the simulation. Once the yearly performance of the power plant has been determined, the results are totalized and the relevant technical, economic, and environmental KPIs are calculated. The calculation of the KPIs include a direct comparison of performance between the particular power plant configuration being simulated – with a particular size of electrolyser and storage – and the conventional CCGT operated under the same conditions (steps "5" and "6"). Since both power plants are operated to cover the same specific electricity load from the grid, the main difference in performance comes from the operational expenses. The conventional CCGT's main operating cost is due to natural gas consumption. In the P2X2P configuration, some natural gas is replaced by H_2, which in turn, requires electricity to be produced. Finally, the KPIs are evaluated by an overarching system multi-objective optimisation routine based on genetic algorithms (GA). This optimisation (step "0") is set to maximise the system's NPV whilst minimizing the CO_2 emissions by varying the PEM size, and the storage size, finding solution regions of interest.

This methodology was applied to the base case – which boundary conditions have been described at the beginning of this section – and then it was applied to a series of cases covering different fuel and electricity markets.

System design

The whole system can be divided in four main components. These are the CCGT, the PEM electrolyser, the H_2 compressor, and the H_2 storage. The following sub-sections describe the process to design, calculate the technical performance, and calculate the investment and operational costs of each component.

<u>Combined Cycle Gas Turbine</u>

The CCGT model used consists of a fixed and variable heat model, which main advantage for this type of analysis is its relative simplicity and little computational time required. The models of the thermal power units (i.e., the topping gas turbine and bottoming steam cycle) are based on the fixed and variable heat rate model (Spelling, o.a., 2014), which distinguishes between the fixed heat that is required to drive the turbines at full speed and maintain synchronization with the grid (at zero output) and the variable heat that is required to produce power. As can be seen in Figure 5, this model effectively captures the efficiency penalty for operating the power cycles at part-load conditions.

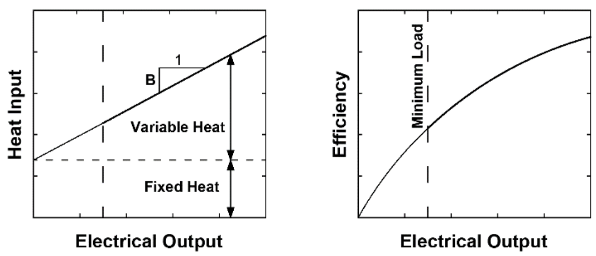


Figure 5. Fixed and variable heat rate model for thermal power

In numerical terms, the heat rate model can be expressed using equation (2), where Q^+ is the heat input required to produce a given electrical output E^{-}, and E_{nom} is the nominal output of the power cycle.

$$\dot{Q}^{+} = A \cdot \dot{E}_{nom}^{-} + B \cdot \dot{E}^{-} \quad (2)$$

The constants A and B are determined using equation (3), based on the efficiency of the power cycle at full load, η_{nom}, and at 50% load, η_{50}. Equation (2) is used to model both the topping gas turbine and bottoming steam cycle, with different values of the constants A and B, based on the relevant efficiencies.

$$A = \frac{1}{\eta_{50}} - \frac{1}{\eta_{nom}} \; ; \quad B = \frac{2}{\eta_{nom}} - \frac{1}{\eta_{50}} \quad (3)$$

In the CCGT, heat in the form of fuel is supplied to the gas turbine, while the heat input for the steam cycle is derived from the gas turbine's exhaust. Applying the conservation of energy to equation (2), the exhaust heat Q_{exh} produced by the gas turbine can be determined using equation (4):

$$\dot{Q}_{exh}^{-} = A_{GT} \cdot \dot{E}_{nom}^{-} + (B_{GT} - 1) \cdot \dot{E}_{GT}^{-} \quad (4)$$

Following this methodology, and with the efficiency values presented in Table 2, the final CCGT efficiency, at nominal conditions, amounts to 57.4%. An additional technical assumption for the CCGT included in the table is its minimum environmental load (MEL). This parameter denotes the lowest operating level, expressed as a percentage of the nominal capacity, at which the CCGT can function due to technical and/or environmental considerations.

Table 2. CCGT technical parameters

Parameter	Symbol	Value	Units
Installed capacity	$P_{CCGT,Des}$	392	MW_{el}
Min env. Load (MEL)	MEL_{CCGT}	40	%
GT eff at 100% load	$\eta_{GT}^{100\%}$	40	%
GT eff at 50% load	$\eta_{GT}^{50\%}$	35	%
SC eff at 100% load	$\eta_{SC}^{100\%}$	29	%
SC eff at 50% load	$\eta_{SC}^{50\%}$	27	%

In this study it is assumed that the H_2-related equipment, i.e., the electrolyser and storage system, are added to a conventional CCGT, which was already installed. Thus, the only investment related to the CCGT, denoted as $CCGT_{Upgrade}$, comes from modifying the combustor chamber to enable H_2 burning capabilities. After internal consultation with gas turbines OEMs and users, and in line with what has been presented in previous reports (YEC-ETN, 2022), it was determined that said modification depends on the maximum H_2 content allowed in the mix. For a H_2 content up to 10%, the main adjustments required are in the control system, and the investment needed is in the order of 5 k€/MW_{el}. For levels of up to 30% changes in materials, burners and combustion chamber are needed, rising the investment needed to around 21 k€/MW_{el}. Finally, for a H_2 content up to 100% major equipment intervention is required and the cost associated to it would be in the order of 51 k€/MW_{el}.

The operating cost of the CCGT, C_{oper}^{CCGT}, is calculated with equation (7). The most important operating cost of the CCGT is due to fuel consumption. Such cost, C_{fuel}^{CCGT}, is calculated by multiplying the total NG consumption of the CCGT over a year, by the price of the natural gas NG_{price} (equation (5)).

$$C_{fuel}^{CCGT} = \sum_{t=1}^{8760} NG_{req,t} \cdot NG_{price} \quad (5)$$

On top of the cost of the NG, there is the cost of the CO_2 emissions, C_{CO2}^{CCGT}, associated to burning said fuel. This is calculated by multiplying the total amount of CO_2 emitted by the CCGT during a year, CO_2^{CCGT} [tonCO_2/year] by the emissions specific cost, spC_{CO_2}.

$$C_{CO2}^{CCGT} = CO_2^{CCGT} \cdot spC_{CO2} \quad (6)$$

$$C_{oper}^{CCGT} = C_{fuel}^{CCGT} + C_{CO2}^{CCGT} \quad (7)$$

The maintenance cost of the CCGT, C_{maint}^{CCGT}, can be divided in three categories: fixed costs, variable costs, and start-up costs. The first two are calculated with equations (8) and (9), where spC_{fixM}^{CCGT} and spC_{varM}^{CCGT} are the specific fixed and variable maintenance costs (13.4€/kW and 2.42€/MWh respectively), and E_{tot}^{CCGT} is the total electric energy produced by the CCGT. The start-up costs are calculated with equation (10) based on the "equivalent operating hours" approach (Spelling, o.a., 2014). In this approach, the wear in the CCGT's components due to each start-up is represented by "normal wear" at normal operation for some equivalent operating hours. Thus, the cost of each start is assumed to be equal to the variable maintenance cost C_{varM}^{CCGT} multiplied by the equivalent number of operating hours ($EOHs$) at full load. The annual cycling cost (or cost due to start-ups) is then obtained by summing the cost for all the starts within the year. The magnitude of the damage or wear caused by each start also depends on the nature of the start, with hot and warm starts resulting in less damage than cold starts. Thus, each type of start-up has a different EOHs; this is calculated with the weighing factors t_c, t_w, and t_h, for cold, warm and hot start-ups respectively in the equation (11), where NSU_x is the number of starts for each hot, warm and cold cases. Values used in previous studies for t_c, t_w, and t_h, are 30, 20 and 10 h/start respectively (Guédez, o.a., 2015).

$$C_{fixM}^{CCGT} = spC_{fixM}^{CCGT} \cdot Size_{CCGT} \quad (8)$$

$$C_{varM}^{CCGT} = spC_{varM}^{CCGT} \cdot E_{tot}^{CCGT} \quad (9)$$

$$C_{SU}^{\mathrm{CCGT}} = \sum_{N_{start}} spC_{fixM}^{CCGT} \cdot Size_{CCGT} \cdot EHOs \quad (10)$$

$$EOH_{SU} = NSU_c \cdot t_c + NSU_w \cdot t_w + NSU_h \cdot t_h \quad (11)$$

$$C_{maint}^{CCGT} = C_{fixM}^{CCGT} + C_{varM}^{CCGT} + C_{SU}^{\mathrm{CCGT}} \quad (12)$$

Finally, the total operation and maintenance cost of the CCGT is given by:

$$C_{O\&M}^{CCGT} = O_{oper}^{CCGT} + C_{maint}^{CCGT} \quad (13)$$

Impact of hydrogen content and ambient conditions

The heat required Q^+calculated with equation (2), is further adjusted for instant values of ambient temperature, ambient pressure, and H_2 content in the mix. The first two come from historical hourly values, whereas the latter is defined by the MILP dispatch optimizer. This adjustment is done using correlations from the work of (Rigaud, et al., 2022). The correlations result in a gradual decrease in heat rate with an increase in H_2 in the fuel mix, i.e., injecting H_2 in the mix increases the CCGT thermal efficiency. Conversely, the correlations for temperature and pressure correction show an increase in efficiency at lower ambient temperatures and pressures. All these increases in efficiency, though, are marginal, as it is only 1.15% when burning 100% of H_2 in the GT, or -1.06% when operating the CCGT at 40 °C.

PEM electrolyser

The PEM electrolyser model was developed and implemented in two stages. In a first stage, a detailed model including all the sub-systems of the electrolyser (stack, dryer, converters, etc.) was developed. This first step included an electro-chemical model and a thermal model for the stack, and an electrical auxiliary model for the electric consumption of the BoP (AC/DC converter, water pumps, drying unit and a chiller). These models were developed using theory available in literature (Pierre, o.a.). Then, they were tuned and validated using data provided by electrolyser manufacturers. This validation took place at cell level and at system level, considering a 1 [MW] electrolyser, and consisted in comparing the electrolyser efficiency under different regimes of operation. After tuning, the models showed a mean relative error (compared against the manufacturer's data) of less than 3%. A detailed description of these models can be found in the work of (Engstam, 2021). The second stage was to generate a map with efficiency values [kWh/KgH_2] for different part-load operation points of the electrolyser (at system level). These values were used to generate a polynomial, which was integrated in the modelling tool as a black box, together with the rest of the components in the layout, to save computational time during the simulations. Said polynomial was derived for a 1 [MW_{el}] electrolyser, but for cases with a different electrolyser size, the polynomial is adjusted considering that larger units are more efficient. It was assumed that a 20 [MW_{el}] electrolyser is 5% more efficient than a 1 [MW_{el}] electrolyser. With that, the efficiency values resulting from the correlation are adjusted accordingly, interpolating in the range 0-20 [MW_{el}]. These electrolysers are modular, and the largest single unit considered was 20 [MW_{el}]; therefore, for electrolysers larger than 20 [MW_{el}], the efficiency remains fixed at that of a 20 [MW_{el}] unit.

As for water requirements, the water required by the electrolyser is calculated following the stoichiometric ratio: $2H_2O \rightarrow 2H_2 + O_2$, and then an efficiency for the water purifier system is considered. For this study, a purifying efficiency of 60% was used, according to manufacturer's recommendations. What this means is that only 60% of the water required by the electrolyser actually undergoes the electrochemical reaction. The rest of the water is disposed of, as well as the O_2 resulting from the reaction.

The cost of the PEM electrolyser is calculated with equation (14). There, C_{PEM}^{Ref} stands for the investment cost of a reference PEM electrolyser; $P_{PEM,Ref}$ is the installed capacity of said reference PEM electrolyser; $P_{PEM,Des}$ is the installed capacity of the PEM electrolyser being modelled (which is an open variable in the optimisation process); and α_{PEM} is the scaling coefficient. The reference values used for C_{PEM}^{Ref}, $P_{PEM,Ref}$, and α_{PEM}, are 3.4 M€, 2.5 MW_{el}, and 0.85 respectively.

$$C_{PEM} = C_{PEM}^{Ref} \cdot \left(\frac{P_{PEM,Des}}{P_{PEM,Ref}}\right)^{\alpha_{PEM}} \quad (14)$$

The operational and maintenance costs of the PEM electrolyser include the cost of water consumed, C_{water}^{PEM}, the cost of the electricity consumed, C_{elec}^{PEM}, and a fixed O&M component. The cost of stack replacement is calculated as well, and accounted for in the economic analysis, but it is not considered inside the yearly O&M of the electrolyser. Instead, it is accounted for in the NPV calculation (details in its respective section below). The cost of the water depends on the amount of water needed and its price. The amount of water consumed, W_{cons}^{PEM} [tonH_2O/year], is calculated following the electrolysis stoichiometric ratio and adding a water purifier efficiency, whereas its price, W_{price} [€/tonH_2O] is assumed at 2 [€/tonH_2O] (Gallardo, o.a., 2022). The cost of electricity depends on the electricity consumed at the time t, and the price of electricity in the DAM at the same moment, $E_{price,t}^{DAM}$. The fixed maintenance component, C_{fixM}^{PEM}, is calculated with equations (17) and (18), where $relC_{fixM}^{PEM}$ is the relative maintenance cost of the PEM (relative to its overnight construction cost, C_{PEM}) [% of direct CAPEX]; and $Size_{PEM}$ is the PEM's installed capacity [MW_{el}]. The equation (18) was determined from data provided electrolyser OMEs.

$$C_{water}^{PEM} = W_{cons}^{PEM} \cdot W_{price} \quad (15)$$

$$C_{elec}^{PEM} = \sum_{t=1}^{8760} E_{cons,t}^{PEM} \cdot E_{price,t}^{DAM} \quad (16)$$

$$C_{fixM}^{PEM} = relC_{fixM}^{PEM} \cdot C_{PEM} \quad (17)$$

$$relC_{fixM}^{PEM} = 0.035785 \cdot Size_{PEM}^{-0.414} \quad (18)$$

Hydrogen compressor

The compressor modelled is a multi-stage rotational compressor. The number of stages considered was three, as recommended by (Roy, o.a., 2006). The compression work is calculated with equation (19), where W_x denotes the power required for compression at a certain compressor stage, k is the polytropic coefficient of H_2, R the universal gas constant, T_{Low} is the reference ambient temperature used for calculating the amount of energy released, $p_{out,x}$ and $p_{in,x}$ are the outlet and inlet pressure of the compressor stage respectively while $\dot{n}_{gas}$ is the molar flow of gas through the compressor.

$$W_x = \frac{k\ R\ T_{Low}}{k-1}\left[\left(\frac{p_{out,x}}{p_{in,x}}\right)^{\frac{k-1}{k}} - 1\right] \cdot \dot{n}_{gas} \qquad (19)$$

The cost of the H_2 compressor is calculated using equation (20), where spC_{H2Comp} is the specific cost of a H_2 compressor (3400 [€/kW]) (Jens, o.a., 2021), and $Size_{H2Comp}$ is the size of the compressor in [kW] being modelled. Said size is determined based on the power required to compress the H_2 mass flow produced by the PEM from its outlet pressure (30 [bar]) to the storage's maximum pressure (200 [bar]).

$$C_{H2Comp} = spC_{H2Comp} \cdot Size_{H2Comp} \qquad (20)$$

The operational and maintenance cost of the compressor, C_{fixM}^{Comp}, is calculated with equation (21), where $relC_{fixM}^{Comp}$ is the relative maintenance cost of the compressor (4% of the investment cost C_{Comp}) (IEA, 2022).

$$C_{fixM}^{Comp} = relC_{fixM}^{Comp} \cdot C_{Comp} \qquad (21)$$

<u>Hydrogen Storage</u>

The storage system includes two components: a short-duration storage or buffer, and the main storage. Both keep the H_2 in a gaseous form inside pressurised vessels but at different pressures. The buffer storage operates at the same pressure as the electrolyser's output, 30 [bar], whereas the main storage operates at a maximum pressure of 200 [bar].

The H_2 storage tanks were modelled using the equations for real gas, using van der Waals equation of state (equation (22)). This equation is similar to the ideal gas law; however, it also includes the constants a and b, which are dependent on the critical temperature and pressure of the gas. Additionally, no pressure or temperature losses are accounted for in the storage.

$$p = \frac{n\ R\ T}{V - n\ b} - a\frac{n^2}{V^2} \qquad (22)$$

The cost calculation of the H_2 storage is calculated with equation (23), where spC_{H2sto} stands for the specific storage cost (470 [€/KgH_2]) (Gallardo, o.a., 2021), and $Size_{H2sto}$ is the size of the storage in [Kg] being modelled (which is an open variable in the optimization problem). Note that the same equation is used for the buffer storage and for the main storage, the only difference is the specific cost value (260 [€/KgH_2]) which differs due to the operating pressure.

$$C_{H2Sto} = spC_{H2Sto} \cdot Size_{H2Sto} \qquad (23)$$

The operational and maintenance cost of the storage, C_{fixM}^{H2sto}, is calculated with equation (24), where $relC_{fixM}^{H2sto}$ is the relative maintenance cost of the storage (1% of the investment cost C_{H2sto}) in [% of direct CAPEX].

$$C_{fixM}^{H2sto} = relC_{fixM}^{H2sto} \cdot C_{H2sto} \qquad (24)$$

MILP operation optimizer

A mixed integer linear programming (MILP) algorithm was implemented to identify the optimal operation strategy based on key technical and operational inputs. Specifically, it identifies which are the best hours of the day to buy electricity from the grid to produce H_2. The algorithm is implemented in the software Matlab, using their proprietary optimization toolbox. The algorithm is half-hourly based, and the constraints and objective function are solved for every day (with an additional 24h period for a sliding time window (Fang, o.a., 2016)). This optimization is repeated for each day of the simulation. The H_2 storage capacity, $M_{H2sto,Des}$, the PEM nominal power consumption, $P_{PEM,Des}$, and CCGT nominal power, $P_{CCGT,Des}$, together with their efficiencies, are considered as the main technical inputs. The electricity price, $p_{el}(t)$, and the electric demand from the grid, $D_{el}(t)$, are the key operation inputs. The objective of the dispatch algorithm is to minimize the operational costs of the power plant, as shown in equation (25). In said equation, $P_{grid}^{purch}(t)$ is the electric power purchased from the grid at the time t, used to run the electrolyser and its BoP; $P_{grid}^{sold}(t)$ is the electric power produced by the CCGT and sold in the DAM; C_{varM}^{CCGT} is the variable maintenance cost of the CCGT; p_{NG} is the price of natural gas; and C_{CO2} is the cost due to CO_2 emissions. The terms $P_{CCGT}^{NG}(t)$ in and $P_{CCGT}^{H2}(t)$, represent the amount of power produced by the CCGT that is attributable to NG and H_2 respectively. For example, if at a given time the CCGT is producing 300 [MW_{el}], and the fuel mix, at that moment, is 70% NG and 30% H_2 (vol based), then the contribution of NG ($P_{CCGT}^{NG}(t)$) in the final electric power output is 267 [MW_{el}], whereas the contribution of H2, $P_{CCGT}^{H2}(t)$, is 33 [MW_{el}]. Finally, the start-up costs are included by implementing the variable $CCGT_{on}(t)$ which is equal to one every time the CCGT is started, thus activating the cost per start-up C_{SU}.

$$\begin{aligned}\bar{F} = min\Bigg[\sum_{1}^{48} & \left(P_{grid}^{purch}(t) - P_{grid}^{sold}(t)\right) \cdot p_{el}(t) \\ & + (C_{varM}^{CCGT} + p_{NG} + C_{CO2}) \cdot P_{CCGT}^{NG}(t) \\ & + C_{varM}^{CCGT} \cdot P_{CCGT}^{H2}(t) + C_{SU} \cdot CCGT_{on}(t)\Bigg]\end{aligned} \qquad (25)$$

The system must obey a set of physical limitations, which define the constraints applied to the optimization problem. Describing them all in detailed would require a full separated article, thus, only the more relevant constraints are described next. Firstly, the CCGT power output – when online – is limited by a maximum and a minimum level, as shown in equation (26), where MEL_{CCGT} stands for the CCGT minimum environmental load. The same constraint applies to the PEM power input, which has a minimum value of 10%, according to manufacturer's recommendations. Secondly, the change in CCGT production, from one time step to the next, cannot be greater than its ramp up/down rates ($Ramp_{CCGT}$) as shown in equation (27), except when starting-up or shutting-down. The ramp-up rate considered is 40% of nominal capacity per hour, whereas the ramp-down rate was set at 50%.

$$P_{CCGT,Des} \geq P_{CCGT}(t) \geq MEL_{CCGT} \qquad (26)$$

$$|P_{CCGT}(t) - P_{CCGT}(t-1)| \leq Ramp_{CCGT} \qquad (27)$$

Thirdly, the total mass of H_2 stored (limited by a maximum and a minimum level, defined in the design stage), is determined via the equation (28), where $M_{H2sto}(t)$ is the mass of H_2 stored at a time t, $H2_{prod}^{PEM}(t)$ is the H_2 produced by the PEM, and $H2_{cons}^{CCGT}(t)$ is the H_2 consumed by the CCGT at the time t.

$$M_{H2sto}(t) - M_{H2sto}(t-1) = H2_{prod}^{PEM}(t) - H2_{cons}^{CCGT}(t) \qquad (28)$$

The output of the optimizer is a half-hourly data set with the proposed operation of each component (on/off/amount) for a full day of operation (step 3 in Figure 4). That dispatch or operation strategy is used by the thermodynamic model (step 4 in the figure) as the control logic. It is in the thermodynamic model where the final electricity and H_2 production and consumption are determined, considering part-load efficiencies and the effect of ambient conditions.

Multi-objective optimisation

The optimal design of the P2X2P system, in terms of size of electrolyser and storage, can change based on different operational scenarios. Consider two systems, "A" and "B", as examples. System "A" is designed to supply electricity to the grid for 16 hours a day (represented by solid blue lines in Figure 2). This means it only has 8 hours left for H_2 production and storage. System "B", on the other hand, needs to provide electricity for just 6 hours per day (depicted by dashed blue lines in the figure), leaving it with 18 hours for producing and storing H_2. Additionally, the size of the electrolyser [MW_{el}] is restricted by the grid connection point's capacity, which we are assuming is equal to the capacity of the CCGT. Taking these factors into account, we can expect system "A" to require a smaller storage capacity compared to system "B". Similarly, fuel and electricity markets, and ambient conditions might also influence the optimal system design.

To find a suitable design for any set of boundary conditions (operation, markets, ambient conditions, etc.), a multi-objective optimisation routine was employed (step 0 in Figure 4). This algorithm was also implemented using the software Matlab and their proprietary optimization toolbox, specifically the genetic algorithms functions.

The optimiser is set to maximise the NPV of the project whilst minimizing the specific CO_2 emissions of the CCGT. The variables of the optimisation problem are the PEM size, in the range [10 - 390] MW_{el}, and the H_2 storage size, in the range [4 - 20] hours. The NPV is calculated with the equation (30), where n_{con} is the number of years it takes to construct and install the new equipment, assumed equal to 1 year; n_{op} is number of years of equipment operation, assumed 25 years; i is the economic discount rate, set at 7%; ΔFCF is annual the free cash flow of the project; and $C_{stack,y}$ is the cost incurred in the year y to replace the stack of the electrolyser. This stack is replaced every 80,000 hours of operation, and costs 40% of the initial electrolyser cost. The $CAPEX$, in equation (30), stands for the total CAPEX, which has a direct and an indirect component. The direct CAPEX is calculated with equation (29). The indirect CAPEX accounts for installation, engineering, and contingencies costs, assumed 10%, 5%, and 5% of the direct CAPEX respectively.

$$CAPEX^{DIR} = CCGT_{Upgrade} + C_{PEM} + C_{H2Comp} + C_{H2Sto} \qquad (29)$$

The ΔFCF (equation (31)) is defined as the difference between the operational profit (OP) of the system being simulated (CCGT+P2X2P) and the operational profit of a conventional CCGT (without P2X2P), or business as usual (BAU) case. This CCGT in the BAU case follows the same electricity production, but only uses NG as fuel. The OP is defined according to equation (32), as the difference between the revenues in the day ahead market and the operational expenditures. Because both configurations (with and without P2X2P) provide the same service, i.e., they cover the same load in the DAM at the same hours of the year, the difference OP comes down to the difference in OPEX.

$$NPV = -\sum_{y=0}^{n_{con}-1} \frac{CAPEX}{n_{con} \cdot (1+i)^y} + \sum_{y=n_{con}}^{n_{con}+n_{op}-1} \frac{\Delta FCF - C_{stack,y}}{(1+i)^y} \qquad (30)$$

$$\Delta FCF = OP - OP^{BAU} \qquad (31)$$

$$OP = Rev^{DAM} - OPEX \qquad (32)$$

The OPEX includes costs due to maintenance (fixed and variable of all components), but also costs due to fuel consumption, CO_2 emissions, and electricity consumption (to produce H_2). The costs due to NG consumption and CO_2 emissions are calculated using the values described in the section "Case study – boundary conditions", which are 130 €/MWh and 80 €/ton respectively. The cost of the electricity purchased to produce H_2, is calculated using the instant electricity price in the DAM.

Reducing the optimisation's computational time

The range of values for the two varying variables of the optimization results in more than 4080 unique possible system configurations. The high number of configurations, coupled with the 0.5-hour timestep resolution and the numerous variables and constraints defined in the MILP, make the entire study computationally intensive, especially when trying to simulate all the 365 days of the year. Thus, an approach was adopted in which each of the four seasons of the year is characterized by one representative week. To define each of these weeks, the year (365 days) was divided in 4 periods. The summer period goes from 45 days before to 45 days after the summer solstice, or from May 7th to August 5th. The same is applied to the winter period, around the winter solstice. Spring and Autumn are the days left in between. Finally, each hourly value of the representative week is calculated as the mean across all the same days of the period selected. For example, the electricity price for Tuesday at 6pm in the representative week of summer is determined by calculating the average of all the Tuesdays at 6pm in the period May 7th to August 5th. As for the electricity price, this method is applied to the weather data. Thus, the simulations are reduced from 365 days to 28, but still capture seasonal changes in markets and ambient conditions across the whole year. At the end of the 28-day simulation, the results are expanded to cover one full year before calculating the KPIs, most of which are yearly based.

RESULTS AND DICUSSION

First set of scenarios (1-6) – low elect. price fluctuation

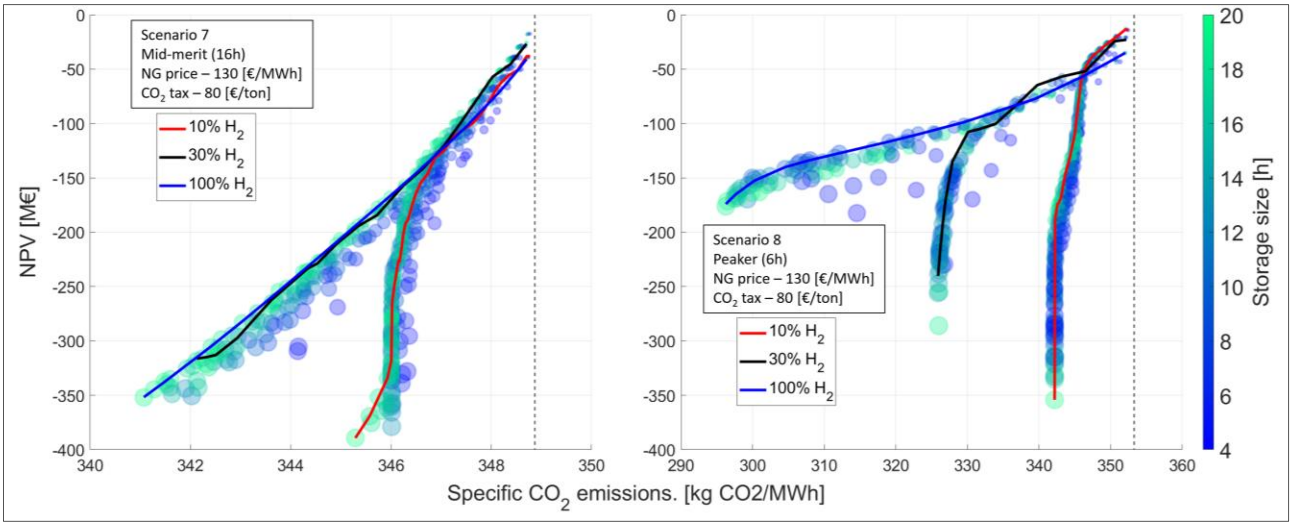
The scenarios 1 to 4 correspond to scenarios with medium and low fuel market prices (130 and 50 [€/MWh], and 80 and 40 [€/tonCO2]). In these scenarios, regardless of the electrolyser and storage sizes, and regardless of the electricity production profile, the electrolyser was hardly ever used. Only in 4 system configurations (out of 8160 possible combinations) did the dispatch optimizer find worth turning on the electrolyser for H_2 production. In these few cases, the electrolyser operated less than 150 hours per year, which renders the project unfeasible from any perspective. Similar results were found for scenarios 5 and 6, which are those with higher fuel prices (210 [€/MWh]). In scenario 5, where the CCGT operates as a mid-merit power plant, only 2 configurations showed some utilisation of the electrolyser, but again, for a very limited number of hours (between 50 and 110 hours per year). In scenario 6, where the CCGT operates as a peaker power plant, approximately 100 different system configurations showed some utilisation of the electrolyser, however, not even one case showed utilisations higher than 30 hours per year.

The main conclusion from this first set of scenarios (from 1 to 6) covering different fuel prices and operation strategies in terms of electricity production, is that even from a pure technical perspective, it is not beneficial, under the conditions and assumptions taken in this study, to retrofit a CCGT to make it a P2X2P system. This is because the complexity added by an additional electrolyser, H_2 compressor, and H_2 storage system – not to mention the even more complex intervention to the combustion chamber of the CCGT – is not worth it because of their very limited hours of operation. A similar argument can be put forward from an environmental point of view. The CO_2 saved from H_2 substituting NG is so insignificant that it does not compensate for the environmental associated to manufacturing and installing the new components in the power plant. Finally, form an economic perspective, the required investment cost is not outweighed by any potential economic benefits. All of this comes as a result of the electricity prices not being low enough compared to the NG price, causing the dispatch optimiser to always favour NG consumption over electricity consumption for H_2 production.

Scenarios 7 to 10 – high elect. price fluctuation and low/mid NG prices

It all gets more interesting when looking at what would happen when more volatile electricity markets, i.e., with larger price fluctuations, are considered. Such is the case of scenarios 7 to 12. Figure 6 shows the results for the first two of them, scenarios 7 and 8. In this figure, each point represents a unique system configuration, i.e., a unique combination of electrolyser and storage size. On the Y axis there is the NPV of the project. Note that "the project" is defined as the addition of H_2 production and utilisation equipment to the power plant. In the X axis there is the specific CO_2 emissions of the power plant. These emissions are the result of burning NG to generate electricity. The black-dashed vertical lines represent the specific CO_2 emissions of the conventional CCGT operated under the same boundary conditions. The colour bar on the right-hand side provides an indication of the size of the storage of each point. Finally, the size of the point signifies the size of the electrolyser. The larger electrolysers are 390 [MW_{el}], limited by the grid connection point, whereas the smaller electrolysers considered are 10 [MW_{el}]. In addition to the points, three solid lines are included in the plot. These represent the pareto fronts identified for different retrofitting levels of the CCGT. The pareto front is formed by a series of optimum solutions found. A point below the pareto front

Figure 6. Results of scenarios 7 (left) and 8 (right) (mid NG prices and high electricity price fluctuation)



is considered not optimum because, for the same specific CO_2 emissions (for the same value in the X axis), there is another point, i.e., another system configuration, that has a greater NPV. A point above the pareto front is, under the conditions considered, not possible because there is no combination of electrolyser and storage sizes that achieve a higher NPV for a given specific emissions value. The pareto fronts identified with the red lines corresponds to systems where the maximum H_2 content in the mix allowed in the CCGT is 10%. The black and blue lines correspond to maximum contents of 30% and 100% respectively.

Scenarios 7 and 8, are the scenarios with medium fuel prices and high electricity price fluctuations. In scenario 7, on the left in Figure 6, the CCGT operates as a mid-merit power plant, whereas in scenario 8, on the right, it operates as a peaker. The first trend identified is that not one single configuration achieves a positive NPV, which means that from a mere economic perspective, this P2X2P system is not feasible under these conditions; however, there are gains from an environmental point of view. The specific CO_2 emissions in scenario 7 can be reduced from 348.9 (value for the conventional CCGT) to 345.3 [kgCO_2/MWh] if the CCGT's burner is upgraded to allow up to 10% of H_2 in the fuel mix. Were the CCGT upgrades allow H_2 values in the mix of up to 30 and 100%, the specific CO_2 reductions would be reduced further to 342.1 and 341.1 [kgCO_2/MWh] respectively. Though not neglectable, this reduction in emissions is very limited as it represents a decrease of only 2%. What this means in absolute values is that the power plant would go from emitting 712 to emitting 696 [ktonCO2] in a year.

The positive environmental impact is more significant is scenario 8, which differentiates from the previous due to the number of hours the CCGT must provide electric power to the grid. In this scenario, the system benefits from having 16 potential hours for purchasing cheap electricity and producing H_2 (compared to only 8 potential hours in scenario 7). Thus, the utilisation of the electrolyser is increased, and the CO_2 emissions go from 353.2 to 342.2, 325.9, and 296.3 [kgCO_2/MWh] for 10, 30 and 100% H_2 present in the mix.

The maximum H_2 content allowed in the mix also has an impact on the results. This is shown more clearly in the plot of the scenario 8. For simulations with smaller electrolysers (points toward the right-hand side of the plot) the system with a maximum of 10% H_2 in the mix (solid red line) performs better in terms of NPV because the investment required to upgrade the CCGT's combustor is less compared to the cases with 30 and 100% H_2. However, as systems with larger electrolysers are considered (moving to the left in the plot), the 10% H_2 in the mix starts to be a limitation. The reason is that larger electrolysers produce more H_2 and, after a certain point, it is more H_2 than what the CCGT is able to consume if it is limited by a maximum of 10% in the fuel mix. That causes the pareto front to drop vertically on the left side, because systems with larger electrolysers have an increased CAPEX, but cannot make use of all the H_2 produced. The same happens for configurations with a maximum of 30% of H_2 in the mix, but these manage to reduce more CO_2 before reaching said limitation.

The limitation due to the maximum H_2 content is also present in the scenario 7, but in this case only for configurations with a 10% H_2 limit. The rest of the configurations (30 and 100% H2) are limited not by the H_2 content in the mix, but by the H_2 produced. In this scenario the power plant is producing electricity for the grid for 16 hours, which leaves less hours available for H_2 production. Thus, the reason the CCGT is not substituting more NG with H_2 is not because it does not have the chance to consume it, but rather because it does not have the time to produce it.

The trends found in scenarios 7 and 8 (medium fuel prices and high electricity price fluctuations) are also identified in scenarios 9 and 10 (low fuel prices and high electricity price fluctuations). Though the trends are similar, the values are slightly different. Because of the lower fuel prices considered in these scenarios, the dispatch optimizer finds even less occasions when it is worth buying electricity to produce H_2 and substitute NG. In general, the operating hours of the electrolysers in these scenarios are half as many compared to those in scenarios 7 and 8. For example, a configuration with a 390 [MW_{el}] electrolyser, a 19 [h] storage system, and a maximum H_2 content in the mix of 100%, would produce H_2 for 695 [h/yr] and would save approximately 39 [ktonCO2/yr] in scenario 8 (mid fuel prices), whereas in scenario 10 (low fuel prices), it would produce H_2 for only 364 [h/yr] and save approximately 23 [ktonCO2/yr]. As for the economic performance, the CAPEX of the system in the example is the same for both scenarios. The electrolyser has a direct cost of almost 249 [M€], the storage 66 [M€], the compression system 29 [M€], and the modifications to the CCGT 20 [M€]; these components, together with any other BoP and the additional indirect costs, make a total CAPEX of 437 [M€]. To give this value some context, that is approximately the same CAPEX required to install a 400 [MW_{el}] CCGT according to (EIA, 2022).

What makes the difference in the final NPV is the OPEX. In scenario 8, not only the NG is more expensive, but also, more NG is substituted with H_2. Table 3 shows partial results of this example configuration with a 390 [MW_{el}] PEM and a storage system with a capacity of 19 [h] for scenarios 8 and 10. The column "BAU" refers to the case where a conventional CCGT (without PEM or H_2 storage) is operated under the same boundary conditions, and against which the results of the P2X2P system are compared.

Table 3. Partial results - PEM 390MW$_{el}$ - Sto 19h

Parameter	Units	SC 8		SC 10	
		BAU	Example config	BAU	Example config
NG cons.	[kton NG]	87.5	73.4	87.5	79.3
NG price	[€/MWh]	130		50	
Cost NG	[M€]	158.1	132.6	60.8	55.1
Elec prod.	[GWh]	681.4		681.4	
Elec purch.	[GWh]	0	267.7	0	140.0
Cost Elec	[M€]	0	1.24	0	-2.80
PEM OH.	[h]	0	696	0	364
H_2 prod.	[kton H2]	0	5.03	0	2.63
NPV	[M€]	0	-176.1	0	-365.2
spf. CO2	[Kg/MWh]	353.3	296.3	353.3	319.9

<u>Scenarios 11 and 12 – high elect. price fluctuation and NG prices</u>

It is not until we consider the most optimistic set of boundary conditions that we finally find positive results, not only from an environmental perspective but also from an economic standpoint. Note that "optimistic conditions" in this context refers to the circumstances expected to have a positive impact for stakeholders interested in deploying this P2X2P. These conditions are (i) higher NG and CO_2 emission prices, and (ii) and increased fluctuation in the daily electricity price profile. The probability of experiencing this combination of conditions, i.e., these scenarios, is debatable. On one hand, the values assumed for NG price and CO_2 taxes seem extreme and far from current values. Only aggressive policies and major disturbances on the current state of the energy market would yield such values. On the other hand, these values are within forecasts from several organizations and the electricity price fluctuation is also expected to increase due to the higher shares of intermittent renewables in the grid.

Figure 7 shows the results for the last two scenarios. In scenario 11, on the left, the CCGT operates as a mid-merit power plant, whereas in scenario 12, on the right, it operates as a peaker. The format used and the way of interpreting this figure is the same as for Figure 6. Both these figures show the trends in NPV and specific CO_2 emissions when varying the electrolyser and the storage sizes. The main difference between this set of scenarios and all the others is that, at least for the peaker operation scheme (right in the figure), the addition of the H_2 related components has a positive impact on its economic performance.

Starting with the mid-merit cases (left on the figure), the results achieved follow the same trends than their counterpart in previous scenarios. This means that greater CO_2 emissions reductions are achieved as larger electrolysers are installed; but with the downside of having even worst NPV values. Also, the maximum H_2 content in the mix limits the environmental gains. This evident in the red line pareto front corresponding to a maximum of 10% of H_2, but also starts to appear in the configurations with a cap of 30% (black solid line). The results are, however, a little more promising as the specific CO_2 emissions in scenario 11 are reduced from 348.9 (value for the conventional CCGT) to 335 [kgCO$_2$/MWh] if the CCGT's burner is upgraded to allow up to 100% of H_2 in the fuel mix. The respective values for scenarios 7 and 9 (other mid-merit cases) are 341 and 344 [kgCO$_2$/MWh]. This decrease in CO_2 emissions is proportional to the utilisation of the electrolyser which, for the base cases of scenarios 7, 9, and 11, are 253, 396.5 and 503 [h] respectively. In terms of NPV, the pareto fronts identified in scenario 11 are less steep (compared to scenarios 7 and 9), which means that the systems are closer to compensate the initial investment and operational expenditures with the reduction in NG consumption.

Finally, the results of the peaker P2X2P system are shown on the right-hand side of Figure 7. This is the set of simulations that achieves promising environmental and economic results under the optimistic group of assumptions considered, namely high NG and CO_2 prices, greater electricity price fluctuations and relatively limited hours of electricity injection to the gird. Some trends are consistent with the previous cases. Larger electrolysers achieve more H_2 production, thus more NG is substituted with H2. This impact, however, is limited by the content of H_2 allowed in the combustions chamber. Thus, larger

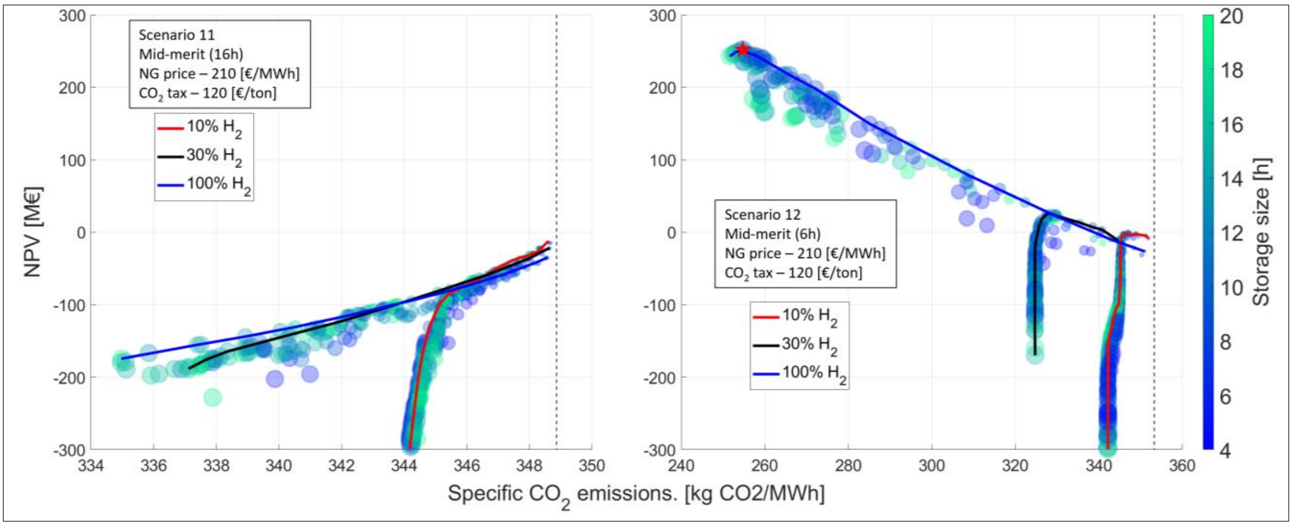


Figure 7. Results of scenarios 11 (left) and 12 (right) (high NG prices and high electricity price fluctuation)

electrolysers are only beneficial if greater contents of H_2 are allowed in the CCGT.

A system configuration, shown in the figure with a red star, has been identified as the optimum design. This is considered so because, among all the configurations investigated in the study, this is the one with the highest NPV and almost the lowest CO_2 specific emissions value. This design has a PEM electrolyser of 380 [MW_{el}], which is close to, but not quite the same as, the maximum value in the range explored (390 [MW_{el}]) and the CCGT installed capacity (392 [MW_{el}]). The storage has the capacity to store 11 [h] of H_2 production at nominal conditions. Finally, the combustion chamber of the CCGT must be able to handle pure H_2 as a fuel source. Systems to the left of the optimum design in the figure achieve greater reductions in CO_2 emissions, but at the expense of greater electrolysers and storage capacities, which bring its NPV down.

Figure 8 shows normalised values of typical day of operation of this "optimum design" system. The first sub-plot (top) shows the normalised CCGT power output (from 0 to 100%, or from 0 to 392 [MW_{el}], in the Y axis) for a full day (24 hours) of operation. The dashed lines represent the MEL of the CCGT. The second sub-plot displays the normalised electric power used by the PEM (from 0 to 100%, or from 0 to 380 [MW_{el}]). This shows how the PEM is activated two times that day, from 04:30 to 06:00 and from 13:00 to 16:00, which corresponds to the two lowest electricity price periods shown in the last sub-plot (bottom). The minimum and maximum electricity prices shown in the plot are 58 and 300 [€/MWh]. Finally, the third sub-plot shows the content of H_2 – on a mass basis – in the storage, which holds a maximum of 79 [ton H_2] and is limited on the lower end to 8.6 [ton H_2]. This minimum H_2 content, shown in dashed lines in the figure, ensures that the pressure in the tank is always higher than what is required by the CCGT. Also shown in the figure is the fact that the CCGT runs on H_2 for approximately 2/3 of its online period before the storage level reaches its minimum. After that moment, the CCGT switches to NG. In this work it is assumed that the CCGT can change constantly and quickly the H_2 content in the fuel mix, however, further technological developments are required to do so.

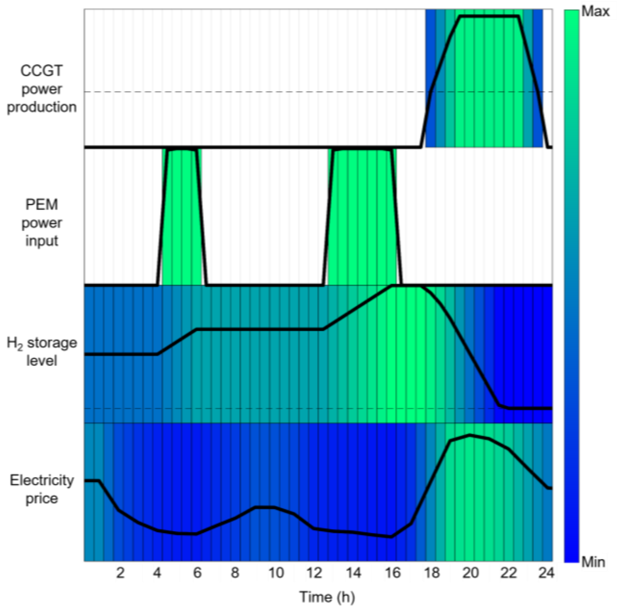


Figure 8. Example of a day of operation

Table 4 shows a summary of the main results for the selected optimum configuration of scenario 12. Starting with the NG, this system consumes almost 30% less fossil fuel than the reference case (conventional CCGT), which means savings in fuel cost of more than 71 [M€] per year. To compensate for that fossil fuel, the power plant needs to purchase 511 [GWh] of fossil-free electricity from the grid to generate 9.6 [kton] of H_2, which amounts to 15.7 [M€] per year. That amount of H_2 is produced over 1338 hours of electrolyser operation, which in turn requires approximately 144000 [m^3] of non-purified water. This system then achieves a NPV of 252 [M€] and specific CO_2 emissions of 255 [$kgCO_2$/MWh], which is about 30% less than the reference case.

One additional factor that needs to be considered in real life applications is the physical space required by a system like this. An electrolyser of such magnitude, together with its compression, storage, and BoP system would require an area equivalent to 2 football fields, which can be challenging to find right next to an existing CCGT power plant.

Table 4. Partial results - Optimum Design

Parameter	Units	SC 12	
		Conv CCGT	Opt. Design
NG cons.	[kton NG]	87.5	63.1
NG price	[€/MWh]	210	
Cost NG	[M€]	255.5	184.2
Elec prod.	[GWh]	681.4	
Elec purch.	[GWh]	0	511.0
Cost elec.	[M€]	0	15.7
PEM OH	[h]	0	1,338
H_2 prod.	[kton H2]	0	9.6
NPV	[M€]	0	251.9
spf. CO2	[kg CO2/MWh]	353.3	254.7
PEM area	[m^2]	0	5,651
Storage cap.	[ton H2]	0	79.2
Storage area	[m^2]	0	3,153
Water cons	[m^3]	0	143,986

CONCLUSIONS

In this work the techno-economic assessment of a P2X2P system based on H_2 production via electrolysis, and utilisation (combustion in GT) has been presented. Different prices of natural gas and CO_2 emissions have been investigated. The influence of future expected electricity price volatilities has been assessed by including additional scenarios with modified hourly electricity prices. Three different values of maximum H_2 content in the fuel mix of the CCGT have been evaluated. Two CCGT operation regimes have been considered, namely mid-merit operation and peaker. Optimised dispatch strategies and system sizing have been identified. The main performance indicators considered throughout the study are the net present value and the specific CO_2 emissions. From the results discussed, the following main conclusions can be drawn:

The system layout proposed is not economically feasible under the current and recent conditions of the fuel and electricity market. These conditions include NG prices of 50 [€/MWh], which is deemed the current value, and 130 [€/MWh], which is the average value of the year 2022. Only in the scenarios with the highest NG price (210 [€/MWh]) this P2X2P system shows a positive economic performance.

Besides these changes in NG and CO_2 prices, the P2X2P system also needs the electricity market to be more volatile. Only in scenarios with high electricity price fluctuations did the CCGT+P2X2P outperformed its respective conventional CCGT.

The utilisation of the electrolyser, and thus the H_2 produced, depends on the operation strategy defined by the dispatch optimiser, which objective function is set to minimise operational costs. Therefore, configurations and scenarios that perform well economically, are the ones that perform better environmentally. In the best-case scenarios, the specific CO_2 emissions by the CCGT can be reduced by 30% due to NG replaced by green H_2.

The intended role of the CCGT in the electric grid has a great impact. When the CCGT operates as a peaker, i.e. when it is online only for a few hours per day, it leverages more from the electricity price fluctuations and finds more occasions when it is worth purchasing cheap electricity for H_2 production.

The maximum % of H_2 injection to the GT has an important effect on the results as it cand drastically limit the H_2 consumption of the CCGT. Under the assumptions taken, if the PEM to CCGT installed capacity ratio is less than 0.076 (PEMs of 30 [MW_{el}]), then an upgrade to allow 10% H_2 is enough. For larger PEMs, between 120 and 30 [MW_{el}] (or 0.28 and 0.076 times the size of the CCGT), an upgrade to 30% is better. For PEMs larger than that and up the same size of the CCGT, the modifications to the CCGT should allow up to a 100% H_2.

Future work will focus on exploring different possible investment costs for the electrolyser and storage system, as well as including additional sources of revenue through services such as balance control in a more dynamic electricity production scheme.

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