IEEE Access
Multidisciplinary ⋮ Rapid Review ⋮ Open Access Journal

Received 3 October 2023, accepted 28 October 2023, date of publication 17 November 2023, date of current version 28 November 2023.

Digital Object Identifier 10.1109/ACCESS.2023.3332917

RESEARCH ARTICLE

The Fusion to Hydrogen Option in a Carbon Free Energy System

UMBERTO GIULIANI[1,2], MARCO AGOSTINI[1,2], CHIARA BUSTREO[1], AND GIUSEPPE ZOLLINO[3]
[1]Consorzio RFX (CNR, ENEA, INFN, University of Padua, Acciaierie Venete SpA), 35127 Padua, Italy
[2]CRF—University of Padua, 35127 Padua, Italy
[3]Department of Industrial Engineering, University of Padua, 35131 Padua, Italy

Corresponding author: Umberto Giuliani (umberto.giuliani@phd.unipd.it)

Eni S.p.A. has contributed to the realization of the present study by funding the PhD scholarship of the main author.

ABSTRACT To address climate change and keep the global temperature increase within 1.5 °C above pre-industrial levels in the long term, ambitious climate policies are required. Decarbonizing all sectors of the economy requires a shift towards electrification. As a consequence, in order to generate a high amount of carbon free electricity, the share of electricity generated by solar and wind power will considerably increase in the years to come. However, the inherent intermittency and variability of both solar and wind power require actions in order to increase the resilience and the flexibility of the power systems and assure the security of supply. To this scope, dispatchable capacity and energy storage systems acting on both short and long terms, will play a pivotal role. The paper discusses various scenarios developed with the COMESE code to investigate the affordability and viability of future possible carbon-free Italian power system configurations, based on both existing and under development energy technologies. The 100% renewable generation option is compared to "nuclear scenarios" where a relevant base-load generation is provided by nuclear fusion power plants. Also, besides the conventional storage systems based on electrochemical devices and pumped hydroelectricity, the deployment of long term storage systems based on hydrogen production, storage and utilization (power-to-hydrogen-to-power, P2H2P) is also investigated. Specifically, excess generation from renewables is used to power electrolysers for hydrogen production. The affordability of this option is evaluated in contrast to the "fusion to hydrogen" strategy, where a continuous hydrogen production for long term storage is provided by fusion electricity. The study proves that the average system cost of electricity for any least-cost 100% renewable power system configuration exceeds that of the corresponding alternative scenario with base-load generation from nuclear power plants. If available, P2H2P works along with batteries as short/medium term storage with benefits on the total system costs, that slightly lowers. Neither converting the whole excess energy into hydrogen in order to avoid curtailment nor operating fusion power plants for a continuous hydrogen production are cost-effective strategies. Indeed, the high costs of the large tank system required for storing hydrogen and the low overall efficiency of the P2H2P process are the primary challenge.

INDEX TERMS Power system model, energy scenarios, nuclear fusion, system cost of electricity, hydrogen, P2H2P, renewable integration.

I. INTRODUCTION

According to commitments taken by a high number of industrialized countries, following the Paris agreement, carbon neutrality should be reached by 2050-2060, almost worldwide. By the end of 2019 the European Commission proposed a Green Deal, according to which carbon neutrality of the EU economy should be sped up with respect to the previous targets. This means that not only power generation (as previously stated by the EU Energy Roadmap) but also the other sectors of the energy system should achieve zero net carbon emissions by 2050 [1].

The associate editor coordinating the review of this manuscript and approving it for publication was Diego Bellan.

As a consequence, in the second half of this century electricity will have to be generated by low-carbon power technologies only, namely: fossil fuelled power plants equipped with Carbon Capture and Storage systems (CCS), renewable-energy power plants, nuclear fission (III+ and IV generations) and, possibly, fusion power plants.

In scenarios with relevant shares of intermittent renewable power generation, the hourly mismatch between demand and generation has to be managed by a combination of short-term energy storage systems and dispatchable generation, to be possibly operated along with long term (seasonal) storage systems (e.g. power-to-gas). A wide literature, only partially covered here, is available on the subject, addressing the issues of feasibility, reliability and costs of power systems with very high shares of variable renewable energy sources [2], [3], [4], [5], [6]. Most of the studies are based on power system models developed and solved in stand-alone unit commitment and economic dispatch tools [7], [8], [9], [10], other are based on a soft-link to energy system models [11], [12].

This paper discusses various scenarios developed with the COMESE code to investigate the affordability and viability of future possible carbon-free Italian power system configurations, based on both existing and under development energy technologies. Indeed, hydrogen is currently considered a promising asset in the energy transition serving both both as a fuel and a storable energy carrier for seasonal storage [5], [13], [14], [15], [16]. Specifically, the study aims to assess the extent to which base-load generation technologies like nuclear fusion as well as power to hydrogen to power (P2H2P) systems [17] can enhance the system reliability and mitigate costs, in comparison to a solar-based system which is indeed typical of a southern EU country like Italy. These analyses address the integration of variable renewable generation and baseload generation in order to design a least cost optimized power system. The integration of these two resources have been analysed also with different approaches, as the maximisation of renewable generation exploitation [18], to what extent can nuclear power output flexibility accomodate growing renewable generation [19], and from the technical point of view of nuclear plants operation in scenarios with high renewable generation shares [20].

To this scope, the 100% renewable generation option is compared to "nuclear scenarios", where a relevant base-load generation is provided by nuclear fusion power plants and alternative options for hydrogen production via electrolysis are investigated. Specifically, hydrogen can be produced by powering electrolysers with excess electricity from surplus events or by using electricity generated by dedicated fusion power plants. The first option is intended to explore whether saving the whole generation and avoiding curtailment is a convenient strategy as it might seem in a saving logic. The latter is instead thought to assess the technical and economic benefits of a continuous hydrogen production from fusion electricity, in contrast to the uneven hydrogen production from over generation events. The option of hydrogen production from nuclear fusion heat is not considered here because of the temperatures required for the chemical process to happen (around 900Â°C in the sulphur-iodine cycle [21]). These temperatures are well above those of the coolants in fusion power plants (300-500Â°C) [22], which are limited by technical requirements of the structural materials [23].

II. THE COMESE CODE

COMESE is a model for the simulation of a power system operation and its economics. COMESE can be used to analyze and compare the performances of different power system designs [24], or to choose among a wide range of generation and storage system options, in order to obtain an optimized design able to ensure the power system feasibility and adequacy [25] at the lowest overall average cost. The time frame of a COMESE simulation usually covers one solar year, but longer time intervals can be considered if the computational capacity is accordingly increased. Regardless of the time frame chosen, the system operation is simulated for its entire length with the chosen time resolution, that's usually one hour.

COMESE does not perform any market simulation in order to solve the unit commitment problem, since the current structure and rules of the electricity market are very likely to change in future years, in order to better integrate growing shares of variable renewable generation [26]. Instead, unit commitment is determined following a fixed, user defined, priority order, based on the degree of flexibility and the specific emissions of the generation technologies.

The hourly operation of each generator and storage system is determined relying a short-term forecast of demand and variable generation. The time window involved in the forecast can be set by the user and usually ranges between hours and days, while the forecast is exploited assuming perfect foresight, allowing to model a joint smart operation of dispatchable generators and storage systems, which is indeed a peculiarity of the code. Specifically, energy storage systems can be charged not only by excess energy from variable RES generation, but also by additional dispatchable generation, so to store enough energy in view of later generation shortages. This approach allow to reduce the installed capacity of dispatchable generators up to a 50%, and to consequently increase their capacity factor (CF), with benefits on the final cost of electricity.

Hourly profiles are required as inputs in order to simulate the electricity demand and the generation from variable RES generators. National TSO [27] database provide for historic time-series of electricity loads and generation from existing RES plants. Profiles for new generators as offshore plants and solar panels equipped with trackers are generated with dedicated tool based on satellite and reanalysis databases [28], [29], [30]. Finally, additional demand profiles for new users are constructed based on data from literature, as described in section IV.

The system under investigation (e.g. one single country) can be split into zones, in order to represent RES generation and electricity demand with higher level of detail, as well as to consider the requirements and constraints of the transmission grid. In this study, the system is divided in six zones, in line with the approach used by TERNA, the Italian national TSO [31], namely: North, Centre-North, Centre-South, South, Sicily and Sardinia. COMESE also includes a model of the transmission grid that can be used to perform a power flow analysis based on a transport model. The model simulates only active power exchanges between zones, as this feature aims at a gross evaluation of the additional grid capacity required to avoid transmission bottlenecks in the high voltage (HV) lines connecting each zone. The so-called copper plate (CP) assumption can also be adopted, either by simulating a single zone, or by allowing any power flow between zones. If zonal representation and power flow analysis are used, the CP assumption still holds inside each zone, i.e. distribution grid and HV energy transmission within a single zone are not part the analysis.

In COMESE, the economic parameter used to compare alternative power system scenarios is the LCOTE (Levelised Cost of Timely Electricity). Defined as the ratio of the levelised cost of all the power system components (generators, storage systems and transmission grid) to the energy for final use, it is calculated as follows:

$$\mathrm{LCOTE} = \frac{\sum_{i=1}^{N_p} (LCOE_i \times E_i) + C_{stor} + C_{grid}}{E_{load}} \tag{1}$$

where $LCOE_i$ is the well known levelized lifetime average cost of electricity generated by the i_{th} technology, E_i and E_{load} are the electricity generated by the i_{th} technology and the annual electricity demand, respectively. C_{stor} is the annual cost of energy storage systems while C_{grid} is the annual cost of the trasmission infrastructure. In the case of systems with a relevant share of RES generation the LCOTE gives a measure of the economic burden for the specific power system configuration required to meet the demand in a ''timely'' manner.

As anticipated, COMESE can be used to define an optimized power system: for doing so it relies on an optimization routine based on the algorithm called Differential Evolution (DE) [32], adapted in order to comply with the analyses of constrained problems. DE is a stochastic metaheuristic technique particularly fit, considering its efficiency and robustness, to the solution of computationally demanding problems based on non-differentiable objective functions. This method is based on populations (different electric system configurations in this specific case) evolving as they search for an optimal (least cost) solution, following a sequence of mutation, recombination and selection typical of evolutionary algorithms. Being each run of COMESE independent from another, it was possible to parallelize the problem, which fits particularly well this kind of algorithm. Compared with other techniques of the same family, like evolutionary computation or genetic algorithms, DE stands out in terms of convergence speed. This has made it possible to cope with complex scenarios as the one here presented, with computation time of some tens of hours on low cost hardware. In principle any COMESE output can be used as objective function or as a feasibility constraint. In this analysis the LCOTE has been used as objective function, in order to search for the least cost feasible system, while two constraints have been imposed in order to deem a system acceptable: the number of hours of loss of load, which must be zero, and the maximum available amount of biomethane, as explained in section IV-A.

The supplementary material provides a detailed description of COMESE, including its inputs and outputs, the logic, the assumptions adopted to simulate power system operations, and the various ways it can be utilized.

III. SCENARIOS RATIONALE

The energy scenarios discussed in this study analyse the impact of two power system assets on the costs of a fully decarbonized Italian electricity system, namely: firm base-load carbon-free electricity generation from nuclear fusion power plants and long-term energy storage based on the Power-to-Hydrogen-to-Power (P2H2P) strategy. Italy is a country with a high solar potential and a relatively limited wind potential compared to northern European countries. Due to the high seasonal variability of photovoltaic generation, exploring long-term energy storage options could significantly impact the system's economics.

In fact, previous studies [24], [33] carried out with COMESE, showed that the availability of a firm base-load technology is beneficial in terms of overall system costs, when compared to alternative power system configurations relying on variable renewables and short term storage technologies only. They also show that, although a relevant share of curtailed energy is present in both cases, in the latter it is much larger. As curtailed energy is primarily due to the seasonal mismatch between renewable generation and electricity demand, long-term energy storage systems might save this energy, while also reducing the required generation capacity and possibly lowering the overall system costs.

Indeed, P2H2P could also operate as a short term storage technology to be used either together with batteries and pumped hydro, or in place of them. Moreover, hydrogen reserves can be used as CO2-free fuel for dispatchable generation delivered by fuel cells or hydrogen turbines, working along with the conventional biomethane OCGT and hydroelectric dam plants. As a result, the fleet of dispatchable generators that fully decarbonized electricity systems may lack [33], would be strengthened.

In a future fully decarbonized energy system hydrogen will be used as an energy vector in some hard-to-abate energy sectors (e.g heavy industries, such as steel, e-fuels, fertilizers production, and long distance transport) [13], [15]. In fact, as it will be described more in detail in section IV, the electricity demand considered for the analyses reported in this paper include a base-load addendum for powering electrolysis plants, working at 90% capacity factor, needed to produce hydrogen for hard-to-abate sectors. However, in this study hydrogen is simply simulated as a vector of the P2H2P storage infrastructure, in a future CO2-free power system with or without a contribution from a firm low-carbon technology such as fusion.

In the power system simulations both hydrogen storage and P2H2P infrastructure are modeled. The following four cases will be discussed: a) No Hydrogen (NH) scenarios: electrolysers, fuel cells and hydrogen storage are not available. Consequently, the power system can rely on short term storage systems only; b) Surplus to Hydrogen (S2H) scenarios: electrolysers, fuel cells and hydrogen tanks can be installed. Electricity generation, whenever exceeding the demand and the required amount for charging short term storage systems (batteries or pumped hydro plants), can be used to generate hydrogen. Hydrogen will be stored in hydrogen tanks to be used at a later stage to generate electricity through fuel cells. c) Surplus to Hydrogen with No Curtailment (S2HNC) scenarios: the same approach as in b) is used, but curtailment is prevented throughout the year. As a consequence, the hydrogen infrastructure is forced to use any surplus electricity whenever it is produced. d) Fusion to Hydrogen (F2H) scenarios: three different shares of the base-load fleet of fusion power plants (namely, 15, 30 or 45 GW, out of the 50 GW available) are used for hydrogen production only via dedicated electrolysis plants working at 80% capacity factor. The F2H case is aimed at investigating whether an increased availability of hydrogen, to be used to fuel dispatchable generators, might allow a better integration and a lower capacity requirement of variable renewables, so to allow an overall cost reduction, regardless of surplus electricity exploitation.

In addition, in order to assess the impact of different assumptions on the possible future costs of selected technologies, two cost options were considered, as specified in section IV-A, namely: the "Net Zero" cost option, where significant cost reductions are assumed, and the "Conservative" cost option with moderate cost reductions compared to today.

IV. POWER GENERATION SCENARIOS

A. SCENARIO ASSUMPTIONS

As discussed in [33], if the constraints imposed by the power grid operation are taken into account by means of an hourly power flows analysis, power systems fully relying on variable renewable generation (mainly solar photovoltaic) are more penalized than power systems relying on a bold baseload generation fleet. Also, in the specific case of the Italian system, unless strong upgrades of the transmission grid are assumed, a power plant siting reflecting the zonal load distribution would be recommended both for photovoltaic generation and short term storage systems, as it would lower the overall power system cost. Based on these considerations, the analyses were conducted using simulations of the power system under the 'Copper Plate' (CP) assumption. This

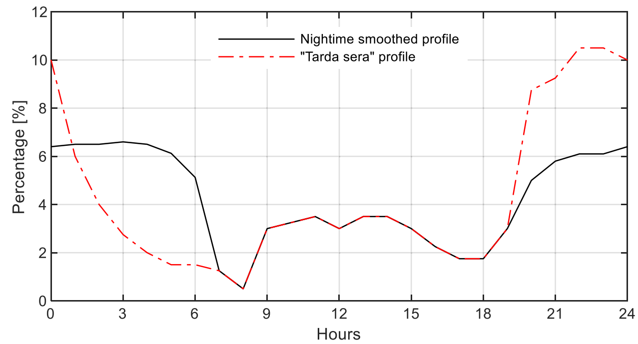


FIGURE 1. Electric vehicles charging profiles.

choice was considered valid since it would penalize scenarios including fusion generation, thus ensuring a conservative approach in the assessment of its beneficial impact. Adopting the CP assumption, also allowed to reduce the computational burden of each simulation, with respect to those including power flow analysis. As a consequence, it was possible to consider a higher number of Decision Variables (DVs) in the optimization process. The distribution of RES capacity across the zones, on the other hand, followed the findings obtained in [33].

Domestic generation is assumed to satisfy the entire electricity demand - neither electricity import nor export are allowed - in order to explore the most demanding circumstances for the country, which must be fully self-sufficient in electricity generation. Modeling international trades would require a Europe-wide analysis that is out of the scope of this paper. However, the possibility of exporting excess generation to neighbouring countries is considered in an ex-post analysis discussed in Section V.

In this paper, the Italian power system operation is modelled in a generic year of the second half of the century when nuclear fusion power plants are likely to be commercially available. The yearly electricity demand is assumed to be 650 TWh, which is about two times higher than today, and is consistent with the estimations of the Italian long term strategy for greenhouse gas emissions reduction [34]. The demand increase is due to a strong electrification of all major end-use sectors (from the current 21,5% to around 55%), which is expected to be a key measure to achieve the goal of carbon neutrality, in addition to a bold reduction in energy intensity. Specifically, the 330 TWh Italian 2019 gross electricity demand is increased by 80 TWh for the complete electrification of the domestic and tertiary sector for space heating, hot water production and cooking, 100 TWh for the complete electrification of private transport and 140 TWh for the production of hydrogen to be used in hard to abate end-use sectors, either directly or as e-fuels [34]. The Italian hourly demand profile has been derived from the national TSO database [27] to which specific profiles of foreseeable future additional loads have been added. Concerning the heat demand for domestic and tertiary sector, the current

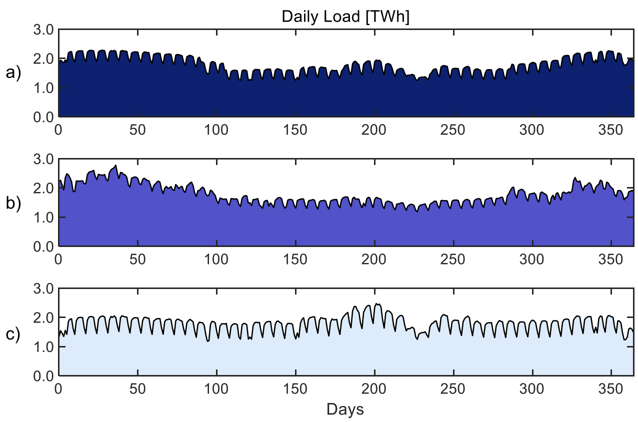


FIGURE 2. Daily demand profiles comparison: a) Simulated profile b) French current demand profile c) Italian current demand profile.

TABLE 1. Installed power and electricity generation per technology.

		Installed power [GW]	Electricity generation* [TWh]
Mature technologies			
Hydro Run of River		5.3	25.0
Dam Hydro		10.5	25.0
Pumped Hydro storage ($\eta = 80\%$)		9.0	0.1
Geothermal		1.2	9.3
Municipal Waste ($\eta = 30\%$)		0.1	0.8
Technologies under development for which cost reductions are expected			
Photovoltaic	Residential rooftop	50.0	59.0
	Ind/comm rooftop	50.0	66.0
	Utility scale (w/ tracking)	DV	**
Wind	Onshore	35.0	70.0
	Floating offshore	DV	**
Fusion		50.0	350.0
Biomethane fired OCGT ($\eta = 42\%$)		DV	**
Electrochemical storage ($\eta = 85\%$) – 8h storage		DV	**
Electrolysers ($\eta = 70\%$)		DV	-
Fuel Cells ($\eta = 60\%$)		DV	-
Hydrogen Tanks and equipment		-	DV

* Energy capacity for storage technologies.
** Model output.

hourly natural gas demand has been converted into electricity demand to power electrical devices (heaters, cookers, heat pumps, etc.), according to the profiles reported in [35] and [36]. As for the electric vehicles, the hourly demand profile shown in Fig. 1 is adopted, and it was obtained adapting the ''tarda sera'' (late evening) profile, also shown in Fig. 1 and taken from [37], by smoothing the night demand profile. Finally, the electricity demand profile for hydrogen production is taken as constant over the year. Due to the high penetration of heat pumps, the peak daily electricity demand during the cold season (autumn and winter) is almost 30% higher than during the hot one (spring and summer). Fig. 2 compares the daily demand profile used in this study (a) to the French (b) and Italian (c) demand profiles as observed in 2019, both scaled up to 650 TWh.

Installed capacity for electricity generation technologies whose potential is already almost completely exploited are user-defined, and the same values apply in all scenarios. On the contrary, installed capacity of technologies with untapped potential are DVs in the optimization problem. In order to set the hourly generation profile of both baseload (geothermal,municipal waste, and run-of-river) plants and variable (photovoltaic and wind power plants) generation, the national TSO database for year 2015 [27] is taken as reference, being 2015 representative of average generation and climate conditions of the last decade. Based on historical data, generation profiles for each technology are constructed as described in the following.

As shown in Table 1, both installed capacity and annual electricity generation of run-of-river hydro, dam hydro, pumped hydro, geothermal and municipal waste power plants are assumed to not increase by 2050. Corresponding values are taken from the national TSO databases [27]. The hourly profiles of run-of-river hydro power plants generation are derived from the national TSO dataset [27]. Those of geothermal and municipal waste power plants are assumed to be baseload. Dam hydro and pumped hydro storage plants hourly generation is an outcome of the simulation.

50 GW of residential rooftop-mounted PV is assumed to be in operation by 2050, along with 50 GW installed on commercial and industrial rooftops, so as to exploit a major share (75%) of the whole available potential reported in [38], assuming 170 W/m^2 potential per unit area. The installed capacity is allocated in the market zones proportionally to the electricity demand. As a consequence the nominal load hours varies in the range indicated in Table 2. It is assumed that panels mounted on commercial and industrial rooftops can be installed with the optimal tilt, which maximizes electricity generation throughout the year. On the contrary, domestic installations are often subjected to several constraints that prevents the installation with the optimal tilt. The capacity factors reached by these generators is consequently lower: in this case the mean CF values from the current Italian photovoltaic generation has been used, taken from [27].

Due to the country morphology and limited wind speed, the Italian onshore wind capacity is set to 35 GW, 25% higher than the assumption in the ''Fit for 55'' PRIMES European scenario [39]. The capacity is assigned to each market zone proportionally to the current geographical distribution, which is a consequence of local average wind speed. As a consequence, 96% are in the Centre-South, South, Sardinia and Sicily zones. The nominal load hours range, indicated in Table 2, has an average value of 2000 hours/year, consistent with the value stated in [39]. In scenarios including nuclear generation, fusion power plant installed capacity is set to 50 GW, generating 350 TWh/y (80% capacity factor), which is 54% of the total electricity demand. To better match demand and generation profiles, we assume that annual maintenance activities are planned so as to allow 90% of the installed capacity to be in operation from October to March, 70% otherwise. As indicated in Table 1, the installed capacities of the remaining technologies (namely, ground mounted utility scale PV, offshore floating wind plants and OCGT generators fuelled by biomethane) are the DVs of the optimization problem.

We assume a theoretical land area availability as large as 20,000 km^2 for utility scale ground mounted PV systems, which is half the difference between the total available agricultural land and the portion presently used for farming activities [40]. In addition, we assume that the utility scale PV plants are equipped with mono-axial tracking. Consequently, the maximum possible value of the installed capacity PV plants, which is a DV, is set at 800 GW. Regardless the total installed capacity, such PV plants are distributed among the market zones proportionally to the electricity demand. The hourly generation profiles are derived from satellite data for the year 2015, properly elaborated [28] to simulate the hourly generation from solar panels equipped with the tracking systems. Consequently, the zonal average nominal load hours vary between 1650 and 1950 hours/year.

Due to the seafloor depth of the windiest offshore sites in Italy, floating offshore wind is a necessary but more complex and costly technological choice. In the simulations we assume that the floating offshore wind capacity, which is a DV, cannot exceed 50 GW (13 times higher than in [39]). Regardless the total installed capacity, plants are evenly distributed throughout the three windiest zones (1/3 in the South market zone, 1/3 in Sicily, 1/3 in Sardinia). The hourly generation profiles are taken from a wind database [30] and adjusted so that the average nominal load hours are optimistically 3000 hours/year (which is 15% higher than in [39]).

OCGT plants fuelled by biomethane are available to generate dispatchable electricity with a high degree of flexibility. The installed capacity is a DV, while the generated electricity cannot exceed 45 TWh, which is a constraint in the optimization problem. This value derives from the national bio-methane potential (107 TWh, as in [46]) with turbine efficiency of 42%.

Storage technologies include batteries with 8 hours storage duration, pumped hydroelectricity plants, as well as the infrastructure needed to produce, store and finally convert hydrogen into electricity, i.e. electrolysers, hydrogen tanks and fuel cells, respectively. As shown in Table 1, batteries, electrolysers and fuel cells installed capacities as well as hydrogen tanks size are DVs, on which no upper bounds are imposed.

Due to the uncertainties on the future cost evolution of some storage and electricity generating technologies, two cost options are considered, namely "Conservative" and "Net Zero", corresponding to moderate and relevant cost reductions by 2050, respectively (Table 2). The aim is to investigate the impact of key technologies still under development, which are likely to experience cost reduction due to further technological learning. The technologies are photovoltaic (both rooftop and utility scale) and offshore floating wind power, batteries, electrolysers and fuel cells.

Regarding photovoltaic, in [47] the cost breakdown is reported for existing plants along with the cost ratio between ground mounted utility scale plants, industrial rooftop plants and residential rooftop plants. In the "Conservative" cost option, with a capital cost (CAPEX) reduction from 300 €/kW to 50 €/kW by 2050 for the modules, the final capital cost for a utility scale plant is 550 €/kW. Then, by keeping the same ratio among residential, industrial and utility scale plants as in [47], the resulting capital cost is 1200 €/kW for residential rooftop installations and 950 €/kW for industrial/commercial rooftop installations. Instead, in the "Net Zero" cost option, the capital cost of utility scale plants is the same as the "Net Zero" cost in [42], i.e. 340 €/kW. Keeping the same ratio among different type of plants, the capital cost for residential installations becomes 750 €/kW and that of industrial/commercial installations 600 €/kW.

As for offshore floating wind plants, in the "Net Zero" cost option, capital cost is taken from [48] and [49]. In the "Conservative" cost option, the capital cost is set at 3000 €/kW, i.e. 50% higher than that reported in [48] and [49].

Highly diverging opinions on future cost reductions of batteries are reported in [50]. In the "Net Zero" cost option, the capital cost reported in [42] is used, i.e. 1080 €/kW (corresponding to 135 €/kWh), while under the the "Conservative" cost options, we assume that the capital cost of storage plants is 50% higher as that reported in [42], i.e. 1600 €/kW (corresponding to 200 €/kWh).

As for hydrogen infrastructure, in the "Conservative" case, capital cost of electrolysers is expected to be as high as in the "stated policies" scenario in [42] and in [50], i.e. 445 €/kW, while the capital cost of fuel cells reaches the same value as in [50], i.e. 800 €/kW. In the "Net Zero" case, electrolyzer capital cost is assumed as large as in "Net Zero" scenario in [42], i.e. 230 €/kW, while fuel cell capital cost is half that in the "Conservative" case. Hydrogen tanks, on the other side, are a conventional technology for which a much lower uncertainty in cost projection can be assumed. Their cost is assumed to be 95 €/kgH_2, as reported in [13], in both cases.

In Table 2, both capital and operation and maintenance costs, together with lifetimes and capacity factors adopted in the LCOE calculation are listed per each technology for both the "Net Zero" and the "Conservative" case.

B. HYDROGEN STRATEGIES

As introduced in section III, four different cases are considered for the possible use of P2H2P infrastructure. For the first three cases, both a fully renewable power system (hereafter referred as "100%RES" scenario) and a system including 50 GW of baseload fusion generation ("FUS50" scenario) are considered. In the fourth case, 50 GW of fusion capacity is available, and the effects of partially using it for hydrogen production are investigated by means of three scenarios. The system design in each scenario is the output of an optimization process. It aims to find the combination of storage and generation technologies able to completely satisfy the demand at the least cost.

TABLE 2. Cost and lifetime options for mature and under development technologies composing the electricity generation mix (values in brackets refer to the "Net Zero" cost option).

		CAPEX [€/kW]		OPEX [€/kWy]	lifetime [years]	Nominal load hours[1] [hours]	LCOE [c€/kWh]	
Mature technologies								
Hydro Run of River[2]		5600		75	60	3100 - 5200	8.9	
Dam Hydro[2]		3400		70	60	2300	-	
Pumped Hydro (η = 80%)[2]		1500		30	60	-	-	
Geothermal[2]		3600		80	30	7900	4.1	
Municipal Waste (η = 30%)[2,3]		4500		140	25	7000	0.5	
Technologies under development for which cost reductions are expected								
Photovoltaic	Residential rooftop	1200	(750)	12	25	1100 - 1350	8.0	(5.3)
	Ind/comm rooftop	950	(600)	10	25	1300 - 1500	5.9	(4.0)
	Utility scale (tracking)	550	(340)	12	25	1650 - 1950	2.6	(1.7)
Wind	Onshore[4]	1300		30	25	1250 - 2400	5.9	
	Floating offshore	3000	(2000)	70	30	3000	9.2	(7.0)
Fusion[5]		6000		110	60	7000	6.4	
Biomethane fired OCGT (η = 42%)[6]		550		20	30	-	-	
Batteries (h= 85%) – 8h storage		1600	(1080)	20	10	-	-	
Electrolysers (η = 70%)		445	(230)	10	20	-	-	
Fuel Cells (η = 60%)		800	(400)	10	20	-	-	
Hydrogen Tanks and equipment (€/kg H_2)[7]		95		-	20	-	-	

[1] The ranges indicate minimum and maximum nominal load hours considering different geographical locations with different generation potential.
[2] Average values as reported in by the EU SET plan SETIS database [41].
[3] Fuel cost is assumed to be negative, -80 €/ton.
[4] Value from IEA Net Zero scenario for the EU [42], with unitary currency conversion rate.
[5] CAPEX, OPEX and LCOE of a future fusion power plant are derived from the literature for a DEMO-like commercial power plant [43].
[6] The cost of biomethane (0.92 €/m^3) derives from the assumptions of digesters (CAPEX: 1,800 €/kW - OPEX: 3%) operating with 90% capacity factor and biomass cost of 5 €/GJ [44]. The result is in line with the estimation reported in [45].
[7] Costs of large tanks and related auxiliaries for hydrogen storage are reported in [13].

In NH scenarios, any installation of electrolysers, fuel cells and H_2 storage is not allowed. Thus, the DVs are the capacity of: ground mounted utility scale photovoltaic, floating offshore wind, biomethane fueled dispatchable generators and electrochemical battery storage. In this case, a rather high renewable capacity is expected to be necessary, as well as a rather large amount of curtailed energy, since dispatchable generation is limited by the domestic biomass production potential.

In S2H scenarios, the hydrogen infrastructure, namely electrolysers, fuel cells and H2 storage tanks, are available options, and their capacities are DVs additional to those previously mentioned. The optimization routine of the COMESE code identifies the optimal amount of excess electricity, which would be otherwise curtailed, to be converted into hydrogen and used to generate electricity at a later stage.

In S2HNC scenarios, another constraint is imposed. The whole excess electricity must be used either to charge batteries or supply electrolysers, that is, curtailment is not allowed. This requires a higher storage capacity and a smaller renewable capacity compared to the previous case. DVs are the same as in the previous case.

In F2H scenarios, some of the fusion power plants in operation supply in-situ electrolysers, operating at 80% capacity factor. As already mentioned in section III, three scenarios are considered with 15 GW, 30 GW and 45 GW of fusion capacity, out of the total 50 GW, for hydrogen production only. This scenarios aim to investigate whether the system costs can benefit from the high capacity factor of the hydrogen infrastructure. The corresponding scenarios are named "F15", "F30" and "F45".

V. RESULTS AND DISCUSSION

A. FUSION AVAILABILITY IMPACT

As shown in Fig. 3, the first clear result is that both with and without an H2 infrastructure operating as storage system, the availability of a baseload generation technology like nuclear fusion reduces the LCOTE. Indeed, under the "Conservative" cost option, the LCOTE of FUS50 scenario ranges from 8.6 to 9.3 c€/kWh. Instead, the LCOTE of 100%RES scenarios is 30%, 28% and 31% higher in NH, S2H and S2HNC cases, respectively. Under the "Net Zero" cost option, the LCOTE of 100%RES scenarios is 14%, 11% and 17% higher than that of FUS50 scenarios, in NH, S2H and S2HNC cases, respectively.

The LCOTE breakdown, detailed in Table 4, shows that the reduction of the costs for storage systems (both short term and H2 infrastructure) and flexible generation, due to baseload electricity production by nuclear fusion power plants, is higher than the cost increase of baseload and variable generation. As shown in Table 2, in this study fusion capex is assumed as large as 6000 €/kW; however, sensitivity analyses have been carried out to assess to what extent the LCOTE of FUS50 scenarios is cheaper than that

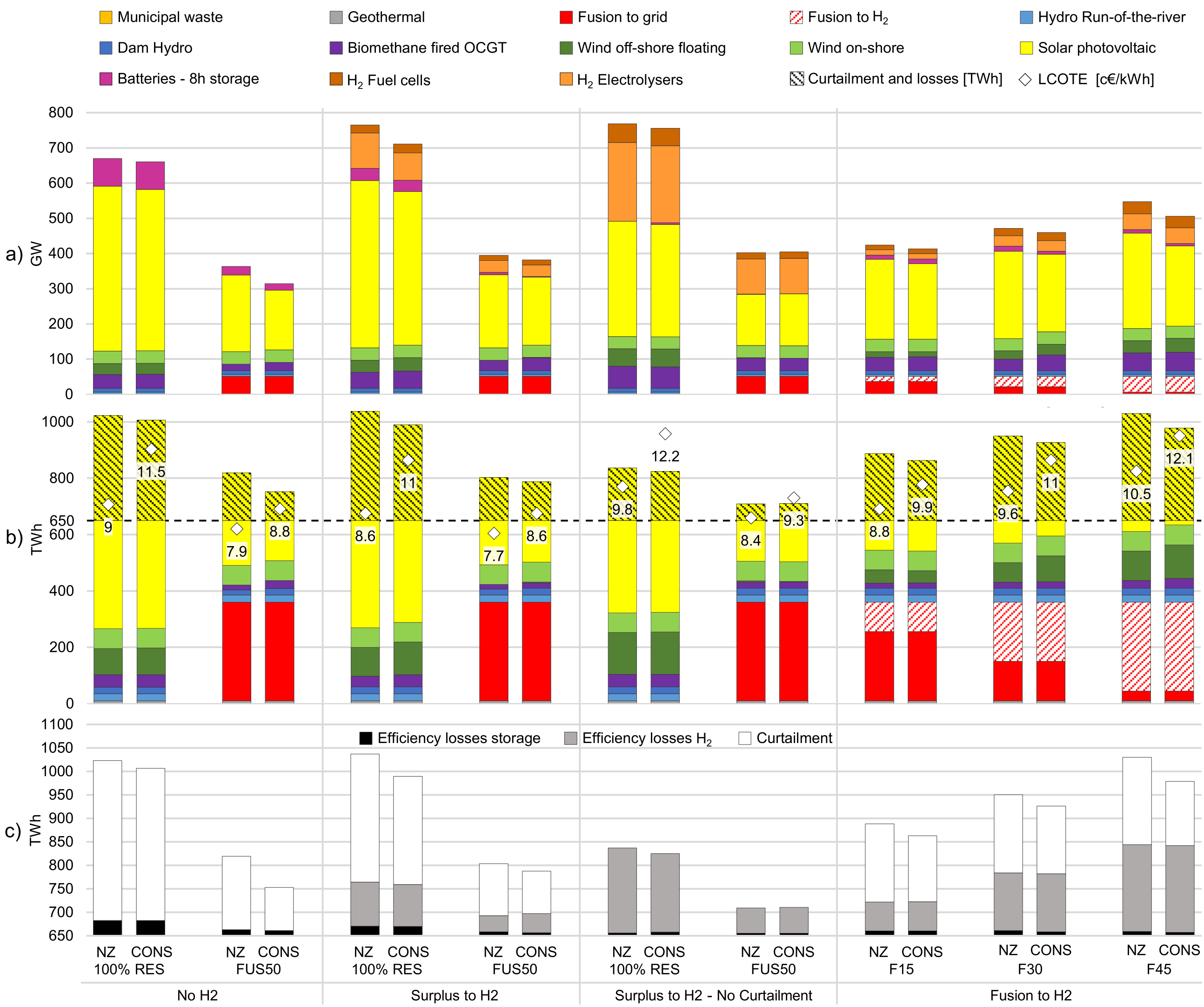


FIGURE 3. **Optimization results for scenarios 100%RES and FUS50 in the four cases presented, in terms of a) power b) energy c) curtailment and losses. Results are shown both for the Conservative (CONS) cost option and the Net Zero (NZ) one. The total demand, equal to 650 TWh, is reported in dashed line.**

of 100%RES scenarios, as described more in detail in the following. Another clear result, visible in Fig. 3, is that, regardless the share of the fusion fleet dedicated to hydrogen production in case F2H, the LCOTE is consistently higher than that of any FUS50 scenarios under the same cost options.

B. P2H2P AVAILABILITY IMPACT

Instead, the availability of H2 infrastructure doesn't have a uniform impact on LCOTE. In fact, as shown in Fig. 3, scenarios in the S2H case are slightly cheaper than in NH case, but those in the S2HNC case are more expensive. Namely, the LCOTE of 100%RES scenario is 4% lower in the S2H case than in NH case, under both the "Conservative" and the "Net Zero" cost options. In fact, as shown in Table 4, generation cost components do not change much. Instead, the reduction of the short term storage systems capacity, largely replaced by H2 infrastructure, lowers the LCOTE. FUS50 scenarios show a similar behavior, but with a lower (2.3%) LCOTE reduction under both the "Conservative" and the "Net Zero" cost options, as the storage cost component is less relevant in these scenarios. Differently, as shown in Table 4, the LCOTE component due to generation in the S2HNC case changes only slightly, while the cost components related to the H2 infrastructure increase significantly. Indeed, whilst the short term storage systems cost component significantly decreases, the LCOTE in the NH case increases because of the large installed capacity of the whole H2 infrastructure that replaces the short term storage systems. Fig. 3 shows that the LCOTE of 100%RES scenarios is 6% higher in the S2HNC case than in NH case under the "Conservative" cost option, 9% higher in the "Net Zero" cost option, instead. The LCOTE increases by 6% in FUS50 scenarios, under both cost options.

TABLE 3. Optimization results in terms of power [GW] (results for Net Zero cost options are reported in brackets).

	No H2		Surplus to H2		Surplus to H2 - No Curtailment		Fusion to H2		
	100%RES	FUS50	100%RES	FUS50	100%RES	FUS50	F15	F30	F45
Generation									
Photovoltaic utility scale	359 (369)	70 (118)	336 (375)	93 (108)	219 (227)	47 (46)	114 (127)	120 (149)	128 (171)
Wind floating offshore	32 (31)	0 (0)	39 (34)	1 (0)	50 (50)	0.5 (1)	14 (16)	31 (23)	40 (35)
Biomethane fired OCGT	40 (39)	24 (19)	49 (46)	37 (30)	61 (63)	35 (36)	40 (38)	45 (33)	52 (50)
Storage									
Batteries – 8h storage	79 (78)	18 (24)	33 (35)	2 (7)	5 (0)	0.5 (0.2)	14 (13)	9 (14)	7 (10)
Electrolysers	0 (0)	0 (0)	78 (100)	33 (34)	219 (224)	101 (100)	15 (15)	30 (30)	45 (45)
Fuel Cell	0 (0)	0 (0)	25 (23)	15 (14)	50 (53)	18 (18)	13 (13)	23 (21)	33 (35)
Hydrogen Tanks [TWh]	0 (0)	0 (0)	4 (2)	0.5 (0.4)	32 (33)	13 (13)	7 (7)	11 (15)	13 (14)

C. P2H2P AS A SHORT TERM STORAGE

The results show that the hydrogen infrastructure has a negligible impact on the total wasted energy (curtailment and efficiency losses). Indeed, it is worth noting that in 100%RES scenario, S2H case, the total electricity generation is almost identical as in NH case (only slightly smaller than in the NH case under the ''Conservative'' cost option, and slightly larger under the ''Net Zero'' cost option). This means that, as shown in Fig. 3, the amount of wasted energy is almost the same. However in the S2H case, curtailed energy decreases and efficiency losses increase in comparison with the SH case, due to the operation of H2 storage systems, which replace a relevant amount of short term storage capacity and operate with a lower roundtrip efficiency compared to short term storage systems. Similarly, the H2 infrastructure does not reduce significantly the amount of overgeneration in FUS50 scenarios. However, in this case overgeneration is slightly higher than in the S2H case under the ''Conservative'' cost option, and slightly lower under the ''Net Zero'' cost option.

Indeed, in both 100%RES and FUS50 scenarios, the amount of energy finally delivered to loads by the storage systems is very similar in the NH and S2H cases (in 100%RES scenarios: 172 vs 160 TWh; in FUS50 scenarios: 55 vs 57 TWh, respectively); however, as in the S2H case P2H2P is available, the installed power of short term storage systems, i.e. batteries and pumped hydro, is much smaller than in the NH case (see Table 3). This means that the H2 infrastructure in the S2H case is not working as a seasonal storage system. As a consequence, the LCOTE reduction achieved in the S2H case is not linked to a reduction of wasted energy, as previously pointed out. This can be better understood through a deeper analysis of the performances of the H2 storage infrastructure. For instance, in 100%RES scenario, under the ''Conservative'' cost option, the P2H2P infrastructure features 69 full load hours in charge and 90 full load hours in discharge and make use of a 103 kt large H2 tank (equivalent to 4 TWh of energy). Comparing these data with the seasonal load, it is apparent that the H2 infrastructure in the S2H case is behaving as a short to medium term storage system rather than seasonal. This is even more evident in the FUS50 scenario of the S2H case, where the full load hours of the H2 infrastructure reduce to 24h (charge) and 23h (discharge) and a 13 kt large H2 tank (0.5 TWh) is installed.

D. P2H2P AS A LONG TERM STORAGE

As for the S2HNC case, it is worth highlighting that forcing the system to prevent energy curtailment implies the identification of a sub-optimal solution. Indeed, the S2H case shows that the optimal solution (minimum LCOTE) corresponds to a system where some curtailment is required and the H2 infrastructure is not operating as long term energy storage.

Nonetheless, the S2HNC case is considered in order to investigate what system would be achievable under this constraint. A different system configuration and operation logic such as that of minimizing the wasted energy could lower the need for important factors, crucial to policy makers, such as construction materials and land occupation, and highlight the magnitude of the resulting system extra costs.

The resulting configuration is therefore the cheapest among those exploiting the whole surplus energy. Unlike the S2H case, in both scenarios of the S2HNC case the short term storage systems installed capacity largely decreases, except for that of pumped hydro systems, whose capacity is not a DV. As shown in Table 3, under the ''Conservative'' cost option, the 100%RES scenario includes only 5 GW of electrochemical storage (79 GW in the NH case and 33 GW in the S2H one), while in the FUS50 scenario very little electrochemical storage capacity is required. Under the ''Net Zero'' cost options, almost no electrochemical storage capacity is present. Moreover, in the 100%RES scenario, the photovoltaic installed capacity is about 30% lower (almost 150 GW less) than in both the NH and S2H cases, under both cost options, while floating offshore wind capacity reaches its maximum allowed value, i.e. 50 GW, under both cost options. In fact, overgeneration is mainly due to the seasonal mismatch between the electricity demand and the solar generation. Therefore, meeting the zero curtailment constraint calls for minimizing their capacity and installing as much as possible both floating offshore wind - which operates more like a baseload power source compared to photovoltaic, and therefore it is less demanding for the H2 infrastructure - and biogas power plants (see Table 3). In the S2HNC case of the FUS50 scenario, under the ''Conservative'' cost option, the photovoltaic capacity is 24% smaller than in the S2H case and 14% smaller than in the NH cases, respectively. It is 30% and 33% smaller than in the S2H and NH cases, under

TABLE 4. Optimization results in terms of LCOTE [c€/kWh] for a) conservative cost option and b) Net zero cost option.

	LCOTE	*Baseload + variable generation*	*Flexible generation*	*Short term storage systems*	*P2H2P infrastructure*		
					Electrolysers	*Fuel cells*	*Hydrogen Tanks*
a)				Conservative cost option			
No H2							
100%	11.5	*6.2*	*2.4*	*2.8*	*0.0*	*0.0*	*0.0*
FUS50	8.8	*6.3*	*1.7*	*0.8*	*0.0*	*0.0*	*0.0*
Surplus to H2							
100%	11.0	*6.3*	*2.5*	*1.3*	*0.5*	*0.3*	*0.1*
FUS50	8.6	*6.5*	*1.5*	*0.2*	*0.2*	*0.2*	*0.02*
Surplus to H2 - No Curt.							
100%	12.2	*6.0*	*2.6*	*0.3*	*1.4*	*0.6*	*1.2*
FUS50	9.3	*6.2*	*1.6*	*0.2*	*0.7*	*0.2*	*0.5*
Fusion to H2							
F15	9.9	*7.2*	*1.5*	*0.6*	*0.1*	*0.2*	*0.3*
F30	11.0	*8.0*	*1.7*	*0.5*	*0.2*	*0.3*	*0.4*
F45	12.1	*8.4*	*2.2*	*0.4*	*0.3*	*0.4*	*0.5*
b)				Net Zero cost option			
No H2							
100%	9.0	*4.6*	*2.3*	*2.0*	*0.0*	*0.0*	*0.0*
FUS50	7.9	*5.9*	*1.2*	*0.7*	*0.0*	*0.0*	*0.0*
Surplus to H2							
100%	8.6	*4.7*	*2.2*	*1.0*	*0.4*	*0.2*	*0.1*
FUS50	7.7	*5.9*	*1.2*	*0.3*	*0.1*	*0.1*	*0.01*
Surplus to H2 - No Curt.							
100%	9.8	*4.6*	*2.5*	*0.2*	*0.9*	*0.4*	*1.2*
FUS50	8.4	*5.6*	*1.5*	*0.2*	*0.4*	*0.1*	*0.5*
Fusion to H2							
F15	8.8	*6.5*	*1.4*	*0.4*	*0.1*	*0.1*	*0.2*
F30	9.6	*6.8*	*1.4*	*0.5*	*0.1*	*0.2*	*0.5*
F45	10.5	*7.2*	*1.8*	*0.4*	*0.2*	*0.3*	*0.5*

the "Net Zero" cost option, instead. Floating offshore wind capacity is still close to zero, like in the S2H and NH cases, for both cost options.

As for the H2 infrastructure, Table 3 shows that in the 100%RES scenario the electrolyzer capacity is much larger than in the S2H case (219 vs 78 GW, and 224 vs 100 GW, under the "Conservative" and "Net Zero" cost options, respectively). This was indeed expected, since the installed power of electrolizers must be as large as the maximum power surplus event in order to meet the zero curtailment constraint. On the contrary, the fuel cell capacity growth is less relevant than that of electrolysers (50 GW in the S2HNC case vs 25 GW in the S2H case and 53 vs 23 GW, under the "Conservative" and "Net Zero" cost options, respectively). In fact, fuel cell capacity is driven by undergeneration events, whose magnitude is much smaller than that of surplus. Finally, the H2 tank size is the H2 infrastructure component experiencing the highest growth, approximately 8 and 16 times larger than in the S2H case, under the "Conservative" and "Net Zero" cost options. In fact, the H2 tank size is a function of the maximum energy that must be stored, that is determined by the surplus (corresponding to the "charge" phase) and undergeneration (corresponding to the "discharge" phase) events. Given the size of the different components of the P2H2P infrastructure just mentioned, the full-load hours in the 100%RES scenario are 209 in charge and 384 in discharge under the "Conservative" cost option, and 210 and 374 under the "Net Zero" cost options. Since the system is forced to work as seasonal storage, the full load hours of P2H2P infrastructure grows consequently.

E. CAPITAL COST LIMITS FOR FUSION

As previously mentioned, a sensitivity analysis on all the FUS50 scenarios was carried out in order to identify the extent to which the capital cost of nuclear fusion can increase while fusion remains beneficial. The overnight cost of a fusion power plant was increased in all FUS50 scenarios, up to the value for which the system cost was equal to that of the corresponding 100%RES scenario. Results show that the breakeven fusion CAPEX depends on both the case and the cost option considered, and varies from 7500 to 8600 €/kW for the "Net Zero" cost option and from 10200 to 11100 €/kW for the "Conservative" cost option, as shown in Fig. 4.

F. ENERGY EXPORT POTENTIAL

As explained in section IV, simulations are carried out under the conservative assumption that electricity imports or exports are not considered viable options during the system operation. Nonetheless, since the results show that overgeneration and curtailed energy remain a relevant feature for all the cases but S2HNC, where a zero curtailment constraint is deliberately set, an assessment of the maximum annual

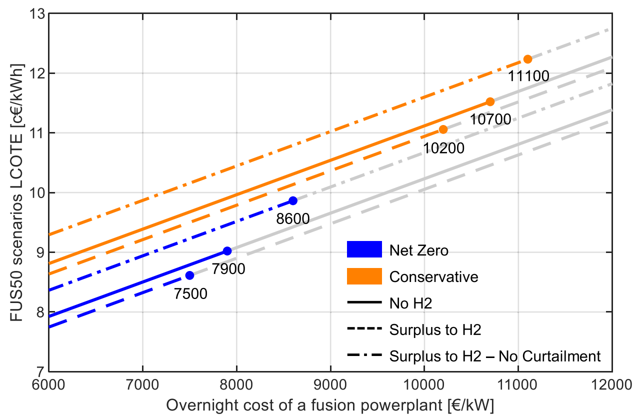


FIGURE 4. **LCOTE sensitivity analysis.**

exportable energy has been conducted. Considering the curtailed energy profiles and the current Italian cross-border transmission capacity (11 GW) [51], the maximum energy export ranges for 24 TWh (in FUS50 scenarios) to 33 TWh (in 100%RES scenarios), assuming an optimistic scenario where all energy exports are imported by neighboring countries. Then, 27% of the energy that would otherwise be curtailed in FUS50 scenarios, and 10% in 100%RES scenarios, could be exported. Even considering a transmission cross-border capacity twice as large as the current one, the potential energy export would range between 34 and 60 TWh, corresponding to 38% and 18% of the curtailed energy.

VI. CONCLUSION

The study proves that in zero-emission solar-based energy systems, firm baseload electricity generation by fusion power plants does contribute to lower the system cost of electricity. This result holds under all the assumptions about storage system availability and operation strategy, namely: availability of batteries and PHS short term storage systems only, availability of both short term and long term storage systems, with the latter based on P2H2P infrastructure and availability of P2H2P infrastructure forced to exploit the entire surplus generation from renewable generators. Indeed, if the fusion fleet is large enough to cover half of the demand, the renewable capacity necessary to meet the remainder is far more than halved as compared to a 100% renewable energy system, while the overall generation and storage capacity is is reduced by almost half. As a consequence, less flexible generation and storage assets are required, with clear cost benefits, as well as on the amount of material requirements and land occupation.

The results show that P2H2P can be effectively deployed as storage technology: if available P2H2P replaces part of the electrochemical storage capacity, allowing to slightly decrease the overall system cost. However, although potentially capable of operating as a long term storage, P2H2P infrastructure is used for short term storage.

This study also shows that converting the whole excess energy into hydrogen to prevent curtailment is not the most effective strategy: if P2H2P is operated as long term energy storage in order to achieve a zero curtailment system, the least cost system design is obtained minimizing the capacity of short term storage systems and relying only on P2H2P. However, due to the higher costs of the P2H2P infrastructure, and mainly of the tanks for H2 storage, the overall LCOTE increases.

These result suggest that a relevant share of curtailed energy could be an intrinsic feature of any optimized energy mix largely based on renewable generation, as pursuing a zero curtailment design and operation strategy would be counterproductive. The scale of the excess energy production is such that, even assuming to be able to export it whenever overgeneration occurs, the system will have to deal with a large share of curtailed energy. This calls for adequate operation and market rules. Nevertheless, a bold base load generation reduces the amount of both excess and curtailed energy.

Finally, due to the low overall efficiency of the P2H2P process, also operating fusion for H2 production for long term storage is not a cost effective strategy.

To conclude, as long as the capex of nuclear fusion power plant is lower than 10200 eur/kWh and 7500 eur/kWh, under "Conservative" and "Net Zero" cost options respectively, the cheapest option for carbon-free generation is a power system where fusion delivers half of the electricity demand, operates jointly with renewables, and excess energy is made available for meeting the load by a mix of electrochemical storage and P2H2P storage, without any seasonal storage strategy.

REFERENCES

[1] *Net Zero by 2050—A Roadmap for the Global Energy Sector*, Int. Energy Agency (IEA), Paris, France, 2021.

[2] H.-K. Ringkjøb, P. M. Haugan, and I. M. Solbrekke, "A review of modelling tools for energy and electricity systems with large shares of variable renewables," *Renew. Sustain. Energy Rev.*, vol. 96, pp. 440–459, Nov. 2018.

[3] W. Zappa, M. Junginger, and M. van den Broek, "Is a 100% renewable European power system feasible by 2050?" *Appl. Energy*, vol. 233, pp. 1027–1050, Jan. 2019.

[4] P. Das, J. Mathur, R. Bhakar, and A. Kanudia, "Implications of short-term renewable energy resource intermittency in long-term power system planning," *Energy Strategy Rev.*, vol. 22, pp. 1–15, Nov. 2018.

[5] D. G. Caglayan, H. U. Heinrichs, M. Robinius, and D. Stolten, "Robust design of a future 100% renewable European energy supply system with hydrogen infrastructure," *Int. J. Hydrogen Energy*, vol. 46, no. 57, pp. 29376–29390, Aug. 2021.

[6] F. Steinke, P. Wolfrum, and C. Hoffmann, "Grid vs. storage in a 100% renewable Europe," *Renew. Energy*, vol. 50, pp. 826–832, Feb. 2013.

[7] C. S. Lai, G. Locatelli, A. Pimm, X. Wu, and L. L. Lai, "A review on long-term electrical power system modeling with energy storage," *J. Cleaner Prod.*, vol. 280, Jan. 2021, Art. no. 124298.

[8] E. V. Mc Garrigle, J. P. Deane, and P. G. Leahy, "How much wind energy will be curtailed on the 2020 Irish power system?" *Renew. Energy*, vol. 55, pp. 544–553, Jul. 2013.

[9] J. Jorgenson, P. Denholm, and T. Mai, "Analyzing storage for wind integration in a transmission-constrained power system," *Appl. Energy*, vol. 228, pp. 122–129, Oct. 2018.

[10] M. Pierro, R. Perez, M. Perez, M. G. Prina, D. Moser, and C. Cornaro, ''Italian protocol for massive solar integration: From solar imbalance regulation to firm 24/365 solar generation,'' *Renew. Energy*, vol. 169, pp. 425–436, May 2021.

[11] J. P. Deane, F. Gracceva, A. Chiodi, M. Gargiulo, and B. P. Ó. Gallachóir, ''Assessing power system security. A framework and a multi model approach,'' *Int. J. Electr. Power Energy Syst.*, vol. 73, pp. 283–297, Dec. 2015.

[12] A. Moore, J. Price, and M. Zeyringer, ''The role of floating offshore wind in a renewable focused electricity system for great Britain in 2050,'' *Energy Strategy Rev.*, vol. 22, pp. 270–278, Nov. 2018.

[13] *The Future of Hydrogen*, Int. Energy Agency (IEA), Paris, France, 2019.

[14] European Commission, *A Hydrogen Strategy for a Climate-Neutral Europe*, Communication From the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, Brussels, Belgium, 2020.

[15] *Global Hydrogen Review*, Int. Energy Agency (IEA), Paris, France, 2022.

[16] F. Peterssen, M. Schlemminger, C. Lohr, R. Niepelt, A. Bensmann, R. Hanke-Rauschenbach, and R. Brendel, ''Hydrogen supply scenarios for a climate neutral energy system in Germany,'' *Int. J. Hydrogen Energy*, vol. 47, no. 28, pp. 13515–13523, Apr. 2022.

[17] M. El-Shimy and A. Afandi, ''Overview of power-to-hydrogen-to-power (P2H2P) systems based on variable renewable sources,'' in *Proc. 5th Int. Conf. Electr., Electron., Inf. Eng.*, vol. 6, 2017, pp. 1–6.

[18] L. Reichenberg, F. Hedenus, M. Odenberger, and F. Johnsson, ''Tailoring large-scale electricity production from variable renewable energy sources to accommodate baseload generation in Europe,'' *Renew. Energy*, vol. 129, pp. 334–346, Dec. 2018.

[19] C. Cany, C. Mansilla, P. da Costa, G. Mathonnière, T. Duquesnoy, and A. Baschwitz, ''Nuclear and intermittent renewables: Two compatible supply options? The case of the French power mix,'' *Energy Policy*, vol. 95, pp. 135–146, Aug. 2016.

[20] P. Denholm, J. C. King, C. F. Kutcher, and P. P. H. Wilson, ''Decarbonizing the electric sector: Combining renewable and nuclear energy using thermal storage,'' *Energy Policy*, vol. 44, pp. 301–311, May 2012.

[21] L. C. Juárez-Martínez, G. Espinosa-Paredes, A. Vázquez-Rodríguez, and H. Romero-Paredes, ''Energy optimization of a Sulfur–Iodine thermochemical nuclear hydrogen production cycle,'' *Nucl. Eng. Technol.*, vol. 53, no. 6, pp. 2066–2073, Jun. 2021.

[22] I. Moscato, L. Barucca, E. Bubelis, G. Caruso, S. Ciattaglia, C. Ciurluini, A. Del Nevo, P. A. Di Maio, F. Giannetti, W. Hering, and P. Lorusso, ''Tokamak cooling systems and power conversion system options,'' *Fusion Eng. Des.*, vol. 178, May 2022, Art. no. 113093.

[23] P. Zacha and S. Entler, ''High heat flux limits of the fusion reactor water-cooled first wall,'' *Nucl. Eng. Technol.*, vol. 51, no. 5, pp. 1251–1260, Aug. 2019.

[24] C. Bustreo, U. Giuliani, D. Maggio, and G. Zollino, ''How fusion power can contribute to a fully decarbonized European power mix after 2050,'' *Fusion Eng. Des.*, vol. 146, pp. 2189–2193, Sep. 2019.

[25] *Mid-Term Adequacy Forecast 2018, Appendix 1: Methodology and Detailed Results*, ENTSO-E, Brussels, Belgium, 2018.

[26] G. Fulli, M. Masera, A. Spisto, and S. Vitiello, ''A change is coming: How regulation and innovation are reshaping the European Union's electricity markets,'' *IEEE Power Energy Mag.*, vol. 17, no. 1, pp. 53–66, Jan. 2019.

[27] Terna. *Transparency Report Terna*. Accessed: Nov. 11, 2023. [Online]. Available: https://www.terna.it/it/sistema-elettrico/transparency-report

[28] T. Huld, R. Müller, and A. Gambardella, ''A new solar radiation database for estimating PV performance in Europe and Africa,'' *Sol. Energy*, vol. 86, no. 6, pp. 1803–1815, Jun. 2012.

[29] (2023). *Renewables Ninja*. [Online]. Available: https://www.renewables.ninja/

[30] (2023). *Wind Atlas*. [Online]. Available: http://windatlas.xyz/

[31] *Individuazione Zone Della Rete Rilevante*, TERNA, Rome, Italy, 2019.

[32] R. Storn and K. Price, ''Differential evolution—A simple and efficient heuristic for global optimization over continuous spaces,'' *J. Global Optim.*, vol. 11, no. 4, pp. 341–359, Dec. 1997.

[33] U. Giuliani, S. Grazian, P. Alotto, M. Agostini, C. Bustreo, and G. Zollino, ''Nuclear fusion impact on the requirements of power infrastructure assets in a decarbonized electricity system,'' *Fusion Eng. Des.*, vol. 192, Jul. 2023, Art. no. 113554.

[34] E. Peschi, A. Caputo, E. Di Cristofaro, M. Colaiezzi, M. Pantaleoni, M. Vitullo, and M. Gaeta, ''Italy's long-term strategy on greenhouse gas emission reduction: Emission scenarios and historical trends,'' Ministry Environ. Energy Security, Rome, Italy, Tech. Rep., 2021.

[35] O. Ruhnau, L. Hirth, and A. Praktiknjo, ''Time series of heat demand and heat pump efficiency for energy system modeling,'' *Sci. Data*, vol. 6, no. 1, p. 189, Oct. 2019.

[36] O. Ruhnau and J. Muessel, ''Update and extension of the When2Heat dataset,'' Econstor Preprints, ZBW-Leibniz Inf. Centre Economics, Kiel, Hamburg, Tech. Rep., 2022.

[37] G. Viganó, C. Michelangeli, M. Rossi, and D. Moneta, ''Confronto tecnico-economico delle alternative di sviluppo Al 2030 della rete di distribuzione,'' RSE, Milano, Italy, Tech. Rep. 21009865, 2021.

[38] P. Ruiz, W. Nijs, D. Tarvydas, A. Sgobbi, A. Zucker, R. Pilli, R. Jonsson, A. Camia, C. Thiel, C. Hoyer-Klick, and F. D. Longa, ''ENSPRESO—An open, EU-28 wide, transparent and coherent database of wind, solar and biomass energy potentials,'' *Energy Strategy Rev.*, vol. 26, Nov. 2019, Art. no. 100379.

[39] *Stepping up Europe's 2030 Climate Ambition Investing in a Climate-Neutral Future for the Benefit of our People*, Eur. Commission Impact Assessment, Brussels, Belgium, 2020.

[40] ISTAT. *Companies and Surfaces*. Accessed: Jul. 11, 2023. [Online]. Available: https://esploradati.istat.it/databrowser/#/it/dw/categories/IT1,Z1000AGR,1.0/AGR_ECON/DCSP_SPA/IT1,102_974_DF_DCSP_SPA_6,1.0

[41] L. A. Roberto, J.-W. Arnulf, V. Marika, S. Bergur, M. Davide, J. Mindaugas, P. F. M. Del Mar, L. Stavros, G. Jacopo, and W. R. Eveline, ''ETRI 2014-energy technology reference indicator projections for 2010–2050,'' Inst. Energy Transp., Luxembourg, U.K., Tech. Rep. LD-NA-26950-EN-N, 2014.

[42] *World Energy Outlook 2022*, Int. Energy Agency (IEA), Paris, France, 2022.

[43] H. Cabal, Y. Lechón, C. Bustreo, F. Gracceva, M. Biberacher, D. Ward, D. Dongiovanni, and P. E. Grohnheit, ''Fusion power in a future low carbon global electricity system,'' *Energy Strategy Rev.*, vol. 15, pp. 1–8, Mar. 2017.

[44] B. Elbersen, F. D. Longa, P. Ruiz, C. Thiel, A. Sgobbi, G. Hengeveld, T. Kober, and W. Nijs, ''The JRC-EU-TIMES model: Bioenergy potentials for EU and neighbouring countries,'' Joint Res. Center, Luxembourg, U.K., Tech. Rep. LD-NA-27575-EN-C, 2015.

[45] B. Jessie, B. Julien, D. P. Hugues, E. Guillaume, F. Malo, and L. Pierre-Laurent, ''Geographical analysis of biomethane potential and costs in Europe in 2050,'' ENGIE, Paris, France, Tech. Rep., 2021.

[46] N. Pierro, A. Giocoli, I. De Bari, A. Agostini, V. Motola, and S. Dipinto, ''Theoretical potential of advanced biomethane in Italy,'' ENEA, Rome, Italy, Tech. Rep. RT-2021-12-ENEA, 2021.

[47] V. Ramasamy, D. Feldman, J. Desai, and R. Margolis, ''Us solar photovoltaic system and energy storage cost benchmarks: Q1 2021,'' Nat. Renew. Energy Lab. (NREL), Golden, CO, USA, Tech. Rep. NREL/TP-7A40-80694, 2021.

[48] *Future of Wind—Deployment, Investment, Technology, Grid Integration and Socio-Economic Aspects*, Int. Renew. Energy Agency (IRENA), Abu Dhabi, (UAE), 2019.

[49] P. Beiter, W. Musial, P. Duffy, A. Cooperman, M. Shields, D. Heimiller, and M. Optis, ''The cost of floating offshore wind energy in California between 2019 and 2032,'' Nat. Renew. Energy Lab. (NREL), Golden, CO, USA, Tech. Rep. NREL/TP -5000-77384, 2020.

[50] V. Viswanathan, K. Mongird, R. Franks, and R. Baxter, ''2022 grid energy storage technology cost and performance assessment,'' *Energy*, Aug. 2022.

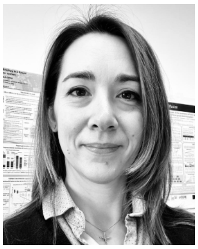
[51] *Net Transfer Capacity—Valori Nominali a Rete Integra 2023*, TERNA, Rome, Italy, 2023.

UMBERTO GIULIANI received the B.S. degree in energy engineering and the M.S. degree in electrical engineering from the University of Padua, in 2015 and 2018, respectively. He is currently pursuing the Ph.D. degree with Consorzio RFX, Padua, within the joint degree in fusion science and engineering between the University of Padua and Ghent University.

His research interests include the simulation and study of decarbonized electricity systems.

MARCO AGOSTINI received the B.S. degree in energy engineering and the M.S. degree in electrical engineering from the University of Padua, Padua, Italy, in 2016 and 2018, respectively. He is currently pursuing the joint Ph.D. degree in fusion science and engineering with Consorzio RFX, University of Padua, and Naples, Italy.

From 2019 to 2021, he was a Research Fellow with the Power Systems Laboratory, University of Padua. His research interests include the application of optimization models to power system operation, local energy market models, region/nationwide energy scenarios, and the policy and market implications of new transactive energy models.



CHIARA BUSTREO received the M.S. degree in electrical engineering and the Ph.D. degree in industrial engineering from the University of Padua, in 2009 and 2011, respectively. Her current research interests include energy policies, energy scenarios, power system modeling, the economic and technological perspectives of energy technologies, system codes for fusion power plant modeling and costs assessment, and the new concepts of fission-fusion hybrid power plants. Her current research activities aim at assessing the role of nuclear fusion in future global, European and Italian energy systems. Since 2016, she has been leading the EUROfusion Workpackage on socio economic studies on fusion.

GIUSEPPE ZOLLINO received the M.S. degree in electrical engineering and the master's Diploma Engineering degree in plasma and controlled thermonuclear fusion from the University of Padua, in 1989 and 1990, respectively. He is currently a Professor of Technologies and Economics of Energy and of Nuclear Fission and Fusion Plants with the University of Padova. His research interests include the several aspects of the electromagnetic design and the analysis of devices for controlled thermonuclear fusion experiments, including the modeling and testing of over-voltages in large magnets, modeling and testing for electromagnetic compatibility assessment, and modeling for eddy current analysis. He took part in the experimental activities on fusion devices, including RFX in Padua, Italy, TPE in Tsukuba, Japan, MST in Madison, USA. His current research interests include the economic evaluation of fusion power plant and on the technical and economic evaluation of future CO2-free power generation scenarios, with and without nuclear energy as a low carbon energy source.

Open Access funding provided by 'Università degli Studi di Padova' within the CRUI CARE Agreement