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Facing the high share of variable renewable energy in the power system: Flexibility and stability requirements

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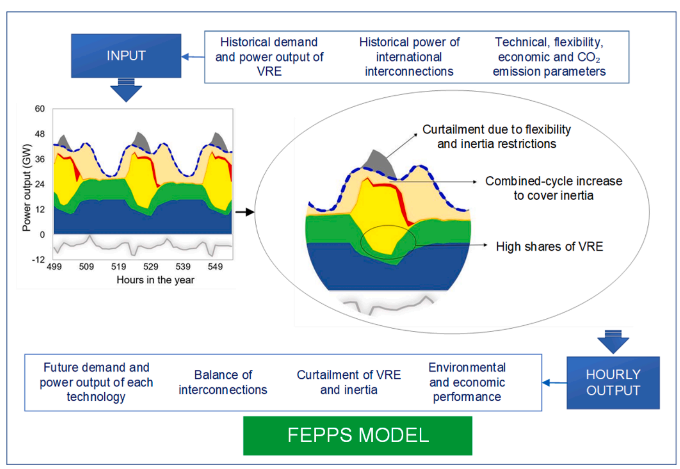
HIGHLIGHTS

- The variable renewable energy (VRE) increase is simulated by modelling.
- The model predicts the feasibility of different decarbonisation scenarios.
- Flexibility and inertia are limiting factors for the forecastable increase in VRE.
- The modelled scenarios do not meet decarbonisation targets for 2030 and 2040.

GRAPHICAL ABSTRACT



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ABSTRACT

Power systems with a high share of variable renewable energy (VRE) represent a challenge to system operators because of the increased flexibility requirements and stability. This study analyses the performance of a real power grid with a high penetration of VRE (mainly wind and solar photovoltaic). A rule-based power model is developed to simulate the power system behaviour. One European country was selected (Spain), with limited

Abbreviations: AC, Alternating Current; CC, Combined-cycle power plants; CIL, Critical Inertia Level; CR, Cogeneration and non-renewable waste; CSP, Concentrated Solar Power; DG, Distributed Generation; DIB, Data in Brief; ENTSO-E / -G, European Network of Transmission System Operators for Electricity / Gas; ERCOT, Electric Reliability Council of Texas; GCA, Global Climate Action; HVAC, High Voltage Alternating Current; HVDC, High Voltage Direct Current; IAM, Integrated Assessment Models; LCOE, Levelized Cost of Electricity; PHS, Pumped Hydro Storage; PNIEC, Spanish National Integrated Energy and Climate Plan 2021–2030; PV, Photovoltaic; REE, Spanish Electricity System Operator (*Red eléctrica de España*); ROCOF, Rate of Change of Frequency; ST, Sustainable Transition; TR, Renewable thermal and other renewables; TS, Solar thermal; TSI, Total System Inertia; TYNDP, Ten Year Network Development Plan; VRE, Variable Renewable Energy.

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Inertia
Power System Stability

international interconnections and well-established decarbonisation scenarios by national and European organisations. Flexibility requirements in the future power system were found through power plants' flexibility and stability constraints (i.e., inertia) and the expected changes in grid interconnection. The model results indicate that the ambitious targets for grid decarbonisation are not realistic because of these requirements. Considering the share of VRE for a sustainable transition (ST) scenario in 2030 (33% power generation) and in 2040 (35%), CO_2-equivalent emissions will be reduced up to 157 and 159 kg CO_2/MWh, respectively, which is well above Paris targets. Furthermore, no scenario allows meeting the expected environmental targets. Therefore, in power systems with more than 39% VRE, the results suggest that new technologies should be considered with emissions below ~113 kgCO_2/MWh, a maximum cost of ~134 €/MWh, and an inertia constant above 5 s.

1. Introduction

The European Union (EU) has developed a set of policies to overcome the challenges of climate change. The energy targets are to cut emissions by at least 55% by 2030 and become the first climate-neutral region in 2050 [1,2]. The initiatives and plans are included under the European Green Deal, which encompasses measures to reduce greenhouse gas emissions, engage society in climate action, and invest in cutting-edge research and innovation [3].

The strategies of the EU Member States are necessary to achieve climate targets, and most of them have included these targets in their legislation and commitments [4]. Regarding the power sector, Paris emissions benchmarks would lead to a decrease in emission intensity of up to 75–80 kgCO2/MWh in 2030 and close to zero by 2040 (considering 265 kgCO_2/MWh in 2019) [5]. Within this context, renewable energies have become competitive technologies for electricity generation because of climate policies, incentives, technological development, and cost reduction [6,7].

Systems with a high share of VRE (wind and solar photovoltaic: PV) represent a challenge for the system operator because of their intermittency, location-specific output, uncertainty, and limits in predictability [7-11]. At a time, the operator may be forced to allow less wind and solar generation than is available; this energy that could potentially be used is known as curtailment. In this way, curtailment occurs by transmission or system balancing constraints on the local network [7,8,12]. Therefore, it is necessary to increase flexibility in power systems to increase VRE generation and deal with its intermittency [8,13,14]. Some conventional power plants cannot quickly adapt their production to the system needs because of technical or economic constraints [14]. Operational restrictions are linked to ramp rates, start-up times, and minimum load limits [9,14,15]. Under these restrictions, power plants could be classified as inflexible, flexible, and highly flexible [15] and with regard to dispatchability, as non-dispatchable, partially dispatchable, and highly dispatchable [16].

VRE, due to their intermittency, are non-dispatchable technologies [16]. Inflexible power plants are designed for baseload operations, for example, nuclear, inflexible combined-cycle and some coal power plants. Flexible power plants such as biomass, concentrated solar power (CSP) with thermal energy storage, flexible combined-cycle, and some coal power plants can adjust their generation and are known as mid-merit order power plants. Highly flexible plants comprise reservoir hydroelectric and aero-derivative and simple cycle gas turbines. They are also known as peak load, and the operating price to increase their flexibility can be very low [15].

In this way, conventional power plants that cannot adapt to flexibility requirements and climate goals (through affordable non-emitting alternatives) must offer their generation below marginal cost to avoid costs of increasing their flexibility or being decommissioned prematurely [14,17]. Moreover, the reduction of conventional synchronous sources and the increase in non-synchronous generators can affect the system stability if the latter cannot provide synthetic inertia and frequency control [7].

In a power system, inertia comes from synchronous generators directly connected to the grid [18]. When the system frequency deviates, the rotating masses of synchronous generators inject kinetic energy into the network or absorb it to counteract the deviation and maintain stability. In contrast, non-synchronous generators, e.g., wind and solar PV, are generally connected to electronic power converters, decoupling the generator from the grid and not inherently contributing inertia. Therefore, in systems with high shares of VRE, the inertia reduction results in a higher rate of change of frequency (ROCOF). Besides, more high voltage direct current (HVDC) links are expected to transport electricity (international interconnections), making the inertia of one system unavailable to the other [18]. However, if systems are connected through the newer Voltage Source Converter (VSC) HVDC technology, inertial response as the primary and secondary frequency control can be provided [19,20].

Various mechanisms or sources of flexibility have been proposed to deal with the challenges of VRE integration. Sources of flexibility include grid expansion, optimal ratios between wind and solar generation, curtailment of renewable energies, energy storage, flexible generation of conventional power plants, demand response, the "Power-to-X" technologies (Power to Gas, Power to Liquids), system diversity, forecast improvement, institutional changes, among others [7,21,22]

Accordingly, different complementary models have been developed to represent VRE integration challenges in power systems [23,24]. Energy models are performed for the long term (e.g., 50 years), have high temporal and spatial aggregation and are also represented in Integrated Assessment Models (IAM) [21,23,25]. Conversely, power models are performed for dynamics in the short term with operational restrictions (generally one year with hourly resolution). Models can be classified into optimisation and rule-based [23]. Optimisation models generally include the effects of VRE investment decisions in an easier way. However, they are more computationally restricted than rule-based (which typically incorporate more technologies and more complicated functional forms) [23]. Optimisation and rule-based models are further discussed in [23], and more detailed classifications are discussed in [21,23,26].

A study developed for California and Texas to provide information on the challenges and opportunities of VRE used historical data (time-series for the same year) for demand, wind, and solar power to maintain temporal and spatial correlations. This simultaneity is essential to incorporate variability since averages artificially smooth the subsequent results [9]. In addition, simulations were performed on the Electric Reliability Council of Texas (ERCOT), using a reduced-form dispatch model (REFLex) with different wind, concentrating solar and PV shares to cover up to 80% of electricity demand [8]. Therefore, the objective was not to focus on the constraints of the current system but rather to identify the flexibility the system would need to accommodate up to 80% of variable generation (hydroelectric, geothermal, and biomass power plants were neglected) [8].

To the best of our knowledge, there are no previous models based on projected data that consider all power technologies, determine the maximum share of VRE (considering technical and stability constraints) and the requirements to achieve environmental targets at a national

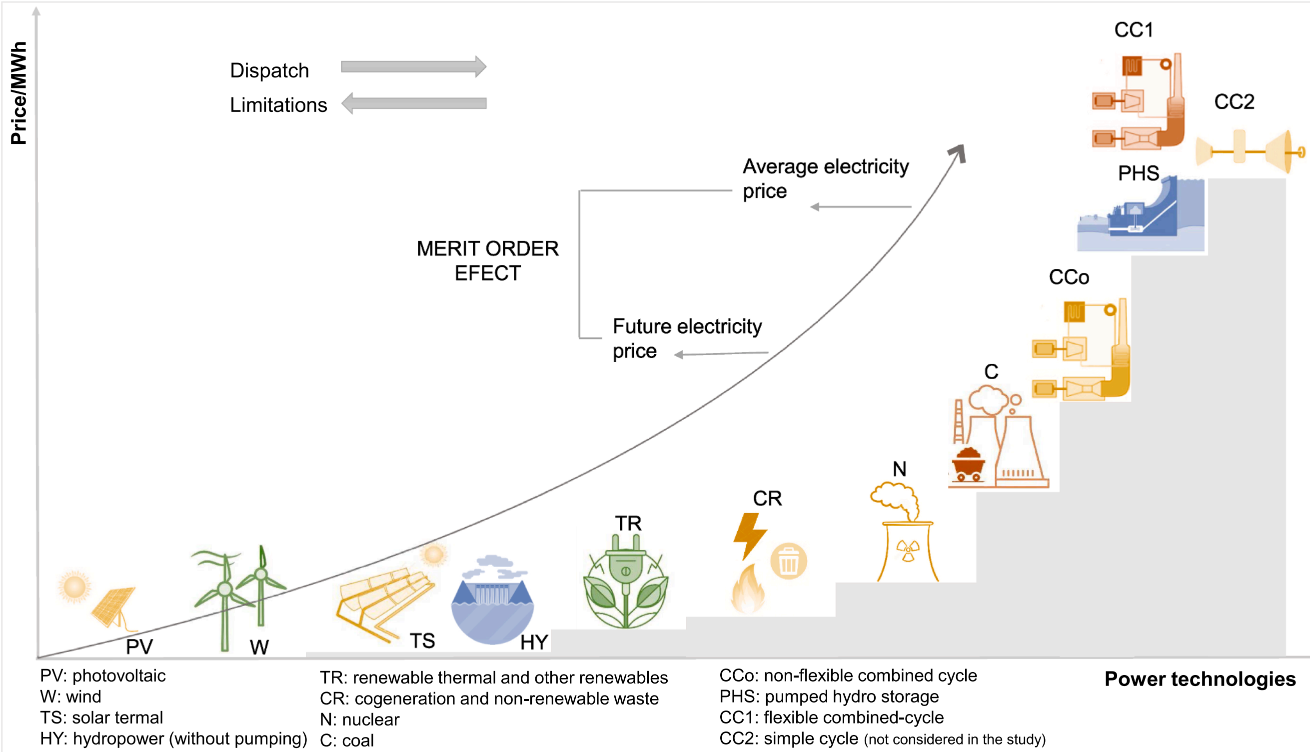

Fig. 1. The merit order effect, power dispatch and limitations.

level. In this context, we developed a linear model called Future Renewable Energy Performance into the Power System (FEPPS). The selected Member State to test our model (case study) is Spain.[1] Spain has well-defined international interconnections, and it is sometimes considered an "electrical island" [27]; therefore, the exchange capacity can be included in the analysis straightforwardly. Moreover, the actions framed in its climate plans and strategies[2] are focused on achieving climate neutrality by 2050, including the electricity sector (which means that approximately 74% renewable generation should be achieved by 2030) [4,6].

Spain has some future projections for its power system, for example, those carried out by the PNIEC [28] or institutions such as the European Network of Transmission System Operators (ENTSO-E, ENTSO-G) through their Ten-Year Network Development Plan (TYNDP) [29]. Some studies have also evaluated the impact of wind curtailment and intermittence on the power system [30-33]. Others assess the performance of technologies, such as concentrated solar power (CSP) [34] or domestic PV systems [35]. In [36], the progress of individual power systems is tracked according to their potential to integrate VRE, and it is considered medium progress for Spain. Therefore, Spain requires adopting best practices to increase flexibility since international interconnections are still insufficient [36] (less than 5% vs at least 10% of the installed capacity recommended by 2020 and 15% by 2030 [37]).

This study aims to determine the future challenges and requirements of the power grid at a national level with high shares of VRE. FEPPS gives an hourly dispatch of all the existing technologies and power exchanged with international interconnections, the curtailment of VRE, emissions and system costs. The model is based on technical and flexibility constraints of conventional power plants and stability requirements, in this case, system inertia. Therefore, FEPPS provides the performance (flexibility, emissions and costs) that new technologies should have to meet the Paris targets while avoiding high system costs.

2. Model description

The developed model is a rule-based power model. It allows representing the challenges of integrating high shares of VRE into the power system with an hourly resolution. FEPPS has a new approach where the residual load is modelled after demand, VRE, solar thermal and hydropower projections. These projections are based on historical data for a common year. Therefore, projected demand is always higher than VRE plus solar thermal power and hydro. The model uses data from the selected power system and considers different dynamics and operational restrictions. Power generation of renewable thermal and other renewables (TR), cogeneration and non-renewable waste (CR), nuclear, coal and combined-cycle power plants (CC) are modelled through future installed capacities and technical and flexibility parameters. The consumption and generation of pumped hydro storage (PHS) are also modelled.

FEPPS incorporates international interconnections (power imports and exports) with future projections. Finally, it ensures system stability by calculating and adjusting system inertia and provides curtailment due to flexibility and inertia constraints. The power dispatch of the different technologies follows the logic of the "cheapest variable cost" [23] or merit order in the power market, both for the supply and limitations (Fig. 1).

Up to now, there are no wide-area (national) power systems with more than 50% annual VRE generation, so it is not possible to validate any model integration (including FEPPS) against real data. Alternatively, it is helpful to consider optimistic and pessimistic scenarios from different approaches [23,38,39].

FEPPS model was validated against historical data of a specific year. It was also compared with the power generation results for 2030 of the Ten-Year Network Development Plan (TYNDP 2018) from the European

[1] Mainland Spain and the Balearic Islands are considered. The Canary Islands are excluded from the analysis since they are not interconnected with the peninsula.

[2] Long-Term Strategy and the National Integrated Energy and Climate Plan 2021–2030 in Spain (*PNIEC*).

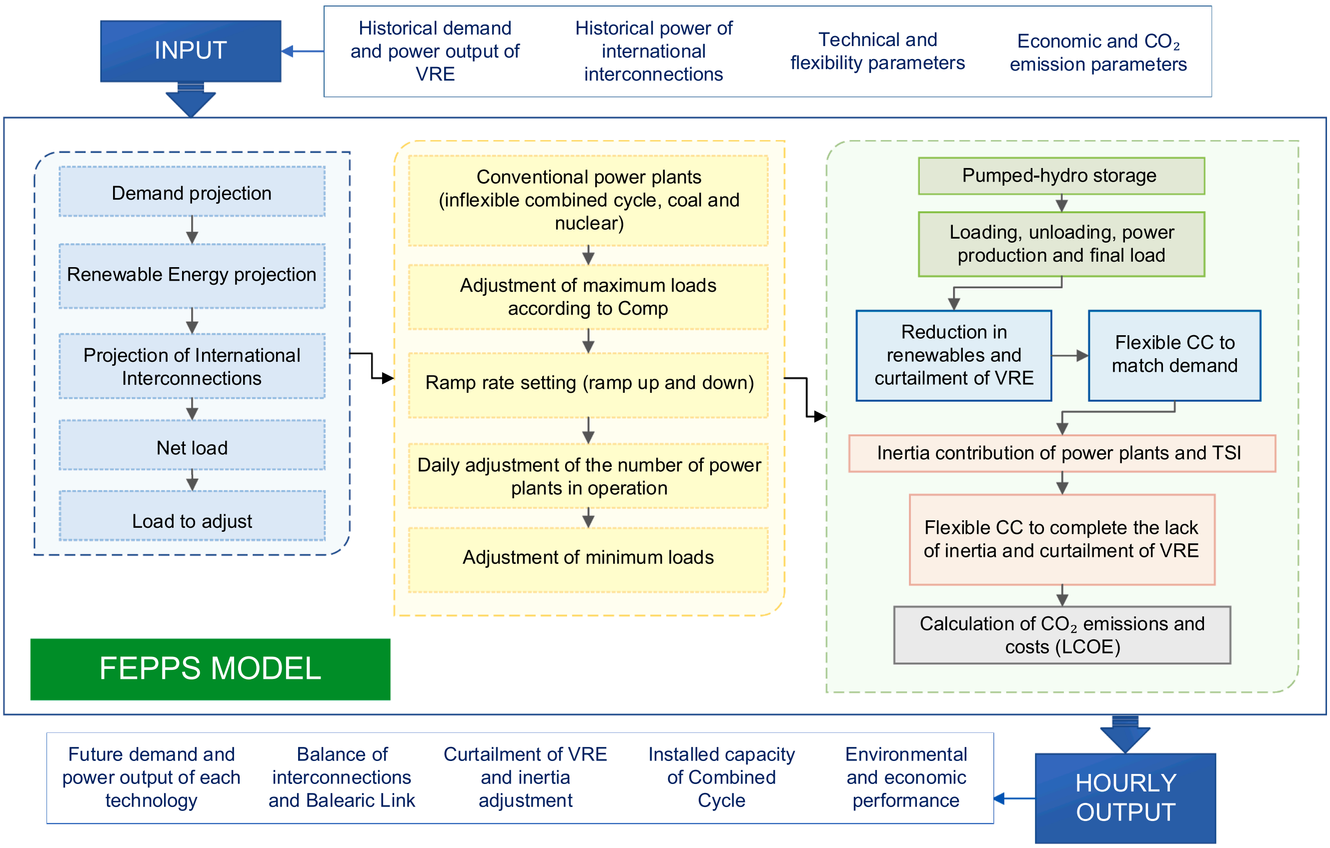

Fig. 2. Structure of FEPPS model: Demand and renewables are projected through historical data. According to the merit order, the residual load is met with conventional electricity generation, considering technical and flexibility parameters. Pumped hydro storage allows surplus energy to be stored for later use, depending on the system's needs. In the hours when there is still a surplus, renewables and VRE are reduced. The residual load is then covered by the combined-cycle. An inertia analysis is developed, which requires further curtailment of the VRE and increased generation from the combined-cycle. Finally, the model provides the economic and environmental performance of each scenario. More detailed information can be found in Fig. 1-DIB and Section 1.1-DIB. An extended flowchart of the algorithm used can be found in Appendix 1-DIB.

Network of Transmission System Operators for Electricity (ENTSO-E). TYNDP 2018 report contains ambitious scenarios that the EU considers realistic to be achieved, and climate conditions are considered for the first time.

TYNDP 2018 scenarios considered are Sustainable Transition (ST), Distributed Generation (DG) and Global Climate Action (GA) by 2030 and 2040 [29]. TYNDP 2018 makes demand and power generation projections for each scenario from three years with different levels of hydro-climate conditions. These are wet, with results obtained from climatic variations of 2007, normal from 1984 and dry from variations of 1982 [40]. Our base scenarios were ST for 2030 and 2040.

FEPPS considers the same or approximate installed capacities as TYNDP. The results are compared with TYNDP dry year results since the historical year selected in our study (2017) was a drought year [41]. Our model includes future cross-border capacities for international interconnections obtained from projects commissioned before 2035 [42]. Using these capacities allows for more realistic data and avoid overestimating the interconnections. Finally, CO_2 equivalent emissions and costs (LCOE) were calculated for each technology and the whole power system. Fig. 2 shows the structure of the model.

3. Methodology

The following section describes the methodology for the study, describing the FEPPS model. Regarding the input data for the selected case study, the Spanish Electricity System Operator, *Red Eléctrica de España* (REE), provides the demand, the generation mix (MW delivered to match demand) including the Balearic link and interconnections, and CO_2 emissions [43]. Based on one-year REE historical data, FEPPS allows representing the behaviour of the future power system. Parameters, variables, and equations used in the model are available in the Data in Brief (DIB).

3.1. Demand

The initial projection of demand is calculated from an hourly historical function where a new minimum demand is assumed. Later, the projected final demand and the initial net load are calculated. The latter is obtained from the power output of each technology (wind, solar thermal, solar PV, hydro, TR, CR) and the projected final demand. That result shows the surplus or lack of load to matching hourly demand. As other technologies are incorporated into the system, the load to be adjusted is recalculated. These technologies are nuclear, coal, PHS and combined-cycles. Therefore, the load is resized according to the flexibility of the technologies, curtailment, and, finally, inertia constraints.

3.2. Power generation technologies

The merit order effect (priority dispatching) and the order to limit participation used in FEPPS are shown in Fig. 1. The limitations arise when there is surplus generation [44]). The merit order is related to the participation of renewable energies and the price of electricity. As their participation in the power system increases, the curve of the merit order shifts to the right, and the price in the daily market becomes lower [45]. In this way, the model represents the general operation of the power system of the selected member state. Hence, renewable energy

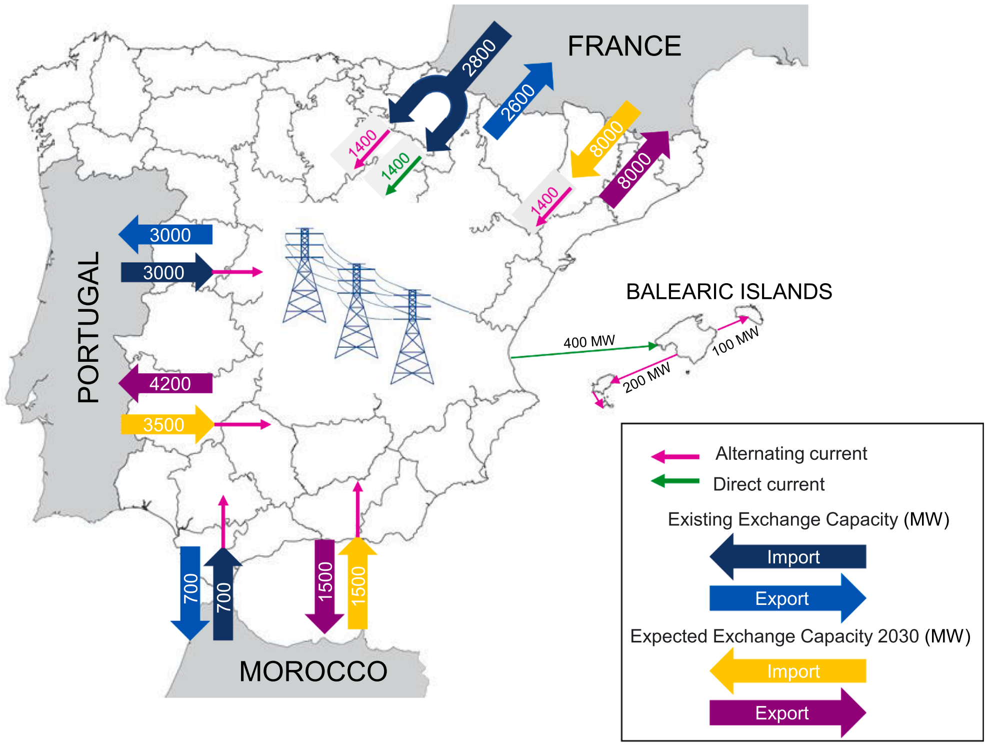

Fig. 3. Existing and expected exchange capacity for Spain-2030 (elaborated based on [42,47–57]).

technologies and, after them, cogeneration power plants have dispatch priority. Nevertheless, the system operator may demand their total or partial temporary disconnection when the operation may affect system stability [46].

3.2.1. Variable renewable energies (VRE) and solar thermal

Demand, VRE and solar thermal projections come from historical data of the same year to consider and preserve temporal and spatial correlations. In this way, FEPPS adjusts to real variations and complementarity of wind and solar power. Besides, it allows determining the necessary power from dispatchable renewable and conventional technologies to meet demand. As the installed capacity of VRE increases, the projections are subsequently adjusted (curtailment) by technical and stability restrictions. Therefore, after curtailment adjustments, the final power output is obtained.

3.2.2. Impoundment and diversion hydropower plants (Hydro)

The historical power is provided as a single time series for conventional and other hydropower plants, pumping and consumption by pumping [43]. However, in this study, PHS was modelled separately, discounting the share of PHS from the historical power output (for more details, see Table 2-DIB). The hydropower output is projected from historical data; therefore, it captures the variability of the selected year. In the case of surplus power, the available hydropower is reduced in the order established for the limitations (merit order). Once the surplus is reduced, the final power output is calculated.

3.2.3. International and other interconnections

FEPPS model includes the transmissions to neighbour systems (international interconnections) and subsystems (i.e., islands). For Spain, REE provides international interconnection exchanges in a single time series (in MW). However, it was necessary to decouple these values to obtain the power imported and exported with each country. The reason is that an increase in interconnection capacity makes it necessary to calculate the new exchange power. The existing and expected interconnection capacities are presented in Fig. 3. Power exchanges are projected through the annual historical installed capacity, historical exchange power (decoupled), and expected installed capacities. Finally, it allows obtaining the import and export balance of the international interconnections and the internal subsystem (i.e., Balearic link).

3.2.4. Renewable thermal and other renewables (TR) and cogeneration and non-renewable waste (CR)

Initially, TR and CR power outputs are equal to each source's maximum power. Later, the power output is resized if there is a surplus generation. Once the excess is reduced, the loads are adjusted for each source depending on their flexibility constraints (minimum loads and ramp rates). The same historical ramp rates were considered for these technologies, and their values in MW are calculated from the new assumed installed capacities.

3.2.5. Nuclear coal and inflexible combined-cycle

FEPPS considers the number of nuclear and coal power plants to calculate the new installed capacity, whereas a maximum power is assumed for the inflexible combined-cycle. The new flexibility limits to apply in the model are minimum loads and ramp rates (ramp up and down). These limits are calculated (through linear regressions) from these installed capacities, minimum historical power, historical ramp rates and theoretical values.

It is also necessary to calculate the number of nuclear and coal power plants operating each hour to adjust the minimum load. A high variation in that number is obtained from one hour to the next due to the high load variation, which is technically unfeasible in the power system. Hence, the model adjusts the number of power plants to limit the minimum loads for each day. It was also considered that coal power plants might be forced, within their technical limitations, to participate with greater flexibility to remain competitive in the market. Finally, the output, which initially corresponds to the maximum power, is resized, and sequentially adjusted according to flexibility characteristics.

3.2.6. Pumped hydro storage (PHS)

PHS was modelled according to its current and future role in the power system, i.e., to store surplus power and to produce electricity. Spain has pure and mixed pumped storage plants, and REE provides a single annual generation data for both technologies (estimating mixed generation) [58]. As a significant amount of the power output in mixed power plants is provided by the natural inflow into the upper basin [59], we have established a PHS availability limit considering the historical generation. The PHS availability limit considers the hydropower generated. In this way, the drought conditions of the selected year are included [60]. For more details, see section 1.1.4-DIB.

In PHS, the energy is stored until there is a load to be covered. Therefore, FEPPS allows discharging while calculating the load that remains in storage.

3.2.7. Flexible combined-cycle (CC)

REE provides a single time series for natural gas combined-cycle power plants. However, in this study, we consider flexible and inflexible combined-cycles. Inflexible CC was modelled (section 3.2.5), while the share of the flexible CC is obtained as a result. Simple cycle or highly flexible gas turbines are not considered because the Spanish power system does not have this technology (only cogeneration plants have these turbines, and they are considered in section 3.2.4). The model obtains the flexible CC power output and its new installed capacity to cover the demand once all the generation technologies participate. The power output is finally adjusted to inertia constraints. Therefore, flexible CC covers the curtailed VRE load due to inertia constraints.

3.3. Curtailment and reduction according to the load to match demand

Once final power outputs are obtained, the first technology to be reduced in the hours with a surplus generation is CR, then TR, hydro, and finally VRE. Consequently, we defined two curtailment requirements. The first curtailment is required for inflexible operation of conventional power plants, i.e., due to technical and flexibility restrictions. The second curtailment is necessary for system stability, specifically for technical constraints of synchronous inertia. Curtailment of VRE and reduction of solar thermal and hydro is carried out according to three levels (Table 1).

In case of a surplus, the model starts at Level 1, curtailing the available wind power, as necessary, up to the indicated percentage. If there is still excess, PV is curtailed. Subsequently, the availability is reduced according to Level 2 values until the model verifies that there is no surplus. Level 1 does not consider hydro and solar thermal power since they contribute inertia to the system. In 2017, 13 573 MW of wind capacity were authorised to provide adjustment services in Spain. PV did not provide these services, while solar thermal and hydro offer 30 MW and 49 MW, respectively [44]. Therefore, for future projections, wind energy will continue participating as well as hydro and solar thermal. As a significant deployment is expected for PV, a curtailment of up to 60% was assumed for ST, and higher values were assumed for DG and GCA.

Table 2
Average rotational inertia constant by technology (s).

Parameter	Value	Reference
Nuclear	4.07	[61]
Coal	2.63	[61]
CC	4.97	[61]
Hydro and PHS	2.40	[61]
CR	2.94	[61]
TR	2.00	[62]
TS	2.50	[62]
Interconnection with France	2.90	*Calculated*[a]
Interconnection with Portugal	2.60	*Calculated*[a]
Interconnection with Morocco	1.70	*Calculated*[a]

[a] Calculated for the model (*further details in the Data in Brief*).

3.4. Inertia of the power system

3.4.1. Inertia of power plants

Rotational inertia constants of technologies and interconnections used in the model are shown in Table 2. These constants enable to calculate the inertia contribution of each technology.

3.4.2. Inertia of international and other interconnections

The model needs to consider inertia coming from alternating current or synchronous interconnections. In systems interconnected by a direct or asynchronous current, inertia does not interact in the transfer process because the HVDC (high voltage direct current) link makes the phenomena that occur on the inverter side AC (alternating current) and in the AC rectifier, independent [63]. The specifications of AC and DC interconnections are provided in Appendix A.

3.4.3. Total system inertia (TSI)

The TSI and the critical inertia level (CIL) were calculated according to [61]. The latter depends on the ROCOF. Frequency gradients between 0.5 and 1 Hz/s exist within the Continental European System (when analysing the events or disturbances over the last 15 years). In future simulations, frequency gradients of 2 Hz/s have been used, according to ENTSO-E [64]. Moreover, typical ROCOF relays installed in 50 Hz systems are set between 0.1 Hz/s and 1.0 Hz/s [65].

Normal variations of the Spanish power system are between 49.85 and 50.15 Hz, and the load shedding process begins at 49.5 Hz [66]. In our model, a sensitivity analysis was performed from a ROCOF level of 0.5 to 3.0 Hz/s to identify the curtailment required by inertia and the level where there are no power grid failures. These levels are used in simulations to evaluate ENTSO-E frequency stability [64]. In this study, a power grid failure represents the amount of renewable energy that has not been possible to reduce after the increase in CC due to inertia requirements. It cannot be done since the curtailment has already reached its maximum level (see Table 1: Level 3). Therefore, with power grid failures, generation would be greater than demand.

Table 1
Curtailment and reduction levels for future scenarios.

Curtailment and reduction	Hydro		Solar thermal		Wind			Solar PV		
	All scenarios		All scenarios		ST scenarios		DG and GCA scenarios	ST scenarios		DG and GCA scenarios
Level 1[a]	n_{1h}	-	n_{1t}	-	n_{1w}	60%	60%	n_{1p}	60%	70%
Level 2[a]	n_{2h}	20%	n_{2t}	20%	n_{2w}	60%	60%	n_{2p}	60%	70%
Level 3[b]	–	–	–	–	n_{3w}	90%	60%	n_{3p}	90%	90%

n_{1h}, n_{2h}: reduction levels for hydro power; n_{1t}, n_{2t}: reduction levels of solar thermal power; n_{1w}, n_{2w}, n_{3w}: curtailment levels for wind power; n_{1p}, n_{2p}, n_{3p}: curtailment levels for solar PV.

[a] Levels that allow the surplus generation to be adjusted. Curtailment required by inflexible operation of conventional plants.

[b] Levels that allow adjusting the system inertia. Curtailment required for system stability (inertia).

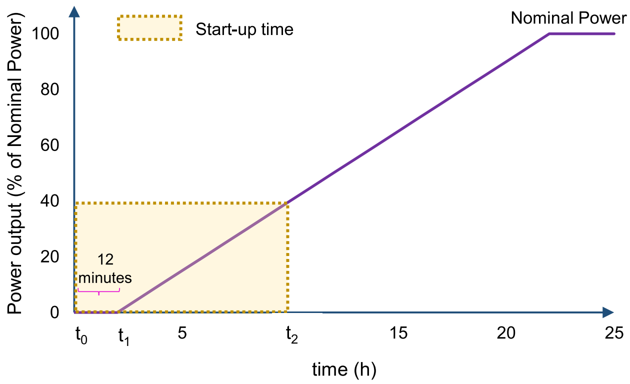

Fig. 4. Start-up from standstill until the nominal operation for flexible CC power plants (elaborated based on [68]).

Table 3
CO_2 equivalent emissions for the technologies of the model.

Technologies	Emission factor (kg CO_2/MWh)	Reference
Wind	10	[72]
Solar PV	40	[73]
Solar thermal	20	[74]
Biomass[a,b]	38	[75]
Biogas[a]	85	[76]
Marine[a,c]	15	[77]
Geothermal[a]	122	[78]
Hydro Impoundment[d]	16.64	[79]
Hydro Diversion[d]	3.79	[79]
PHS[d,e]	1.22	[79,80]
Nuclear[f]	22	[81]

[a] Considering as one technology, the percentage of participation in the installed capacity of biomass, biogas, marine and geothermal is 82%, 14%, 3% and 2%, respectively, for future scenarios, according to [28].
[b] Value for forest residues (pellets).
[c] Value for tidal energy.
[d] Considering as one technology, impoundment and PHS account for 88% of installed capacity and diversion for 12% [82].
[e] Emissions from the reservoirs account for 0.2 % of the greenhouse gas emissions from Europe PHS stations (609.2 kgCO_2/MWh· 0.2%). The electricity generated from the pumps is not considered in this study.
[f] Mean value for pressurised water reactor (PWR).

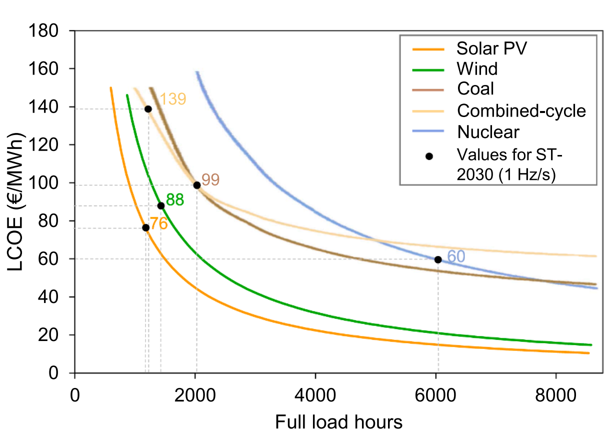

Fig. 5. LCOE vs full load hours (based on [83-85]).

3.5. CO_2 emissions

Data from the power grid is already available in all European Member States. For example, REE provides CO_2 emissions associated with power generation in Spain [43]. The emissions correspond to coal, CC and CR, and are calculated by multiplying the instantaneous power by emission factors [67]. However, this approach does not sufficiently consider the mode of operation, which may play a decisive role in the real emissions of future power plants.

Table 4
LCOE of selected generation technologies (2030 and 2040 scenarios).

Technology	LCOE (€/MWh)	Reference
Solar Thermal	100 110[a] 83[b]	[88,89]
Biomass	85	[88]
Biogas	50	[88]
Marine	107	[90]
Geothermal	69	[91]
Hydro (Impoundment and PHS)	50 / 55[a]	[88]
Hydro Diversion	30	[88]
Cogeneration	52	[91]

[a] Value used only for 2017.
[b] Value used only for 2040 (average between 2030 and 2050).

3.5.1. Emissions methodology with flexible CC mode of operation

REE emissions are not related to power plants mode of operation. This study performs this analysis considering the start time of flexible CC (which supplies electricity at the end of the merit order). This period is the one that elapses from the start of the operation until the minimum load is reached. The start-up time of the different technologies varies significantly, as well as the downtime and the cooling rate [68]. Fig. 4 shows that no power is fed to the network until t_1 after the start-up time (t_o). Subsequently, power gradually begins to be delivered, and the start time elapses until t_2 (minimum load). A steeper slope means a shorter start time [68].

The number of starts and stops creates a transitory fuel consumption without power transmission to the grid [69]. As flexible CC starts and stops will increase with VRE penetration, the modelling of their environmental impact becomes more relevant. Since there is no agreement on how to define cold, warm and hot start times for CC power plants [15,70,71], the criteria established in [15,68] are used. Hence, the hot start is when the power plant has been out of operation for less than 8 h. In the model, flexible CC adjusts hourly generation last, so 1-hour hot start time is implicit, matching the most flexible value of the most commonly used power plants [68]. Given the difference and variations from t_0 to t_1, 20% of the start time is assumed (i.e., 12 min). The emission factor for a hot start (0.59 tCO_2/MWh) [70] and REE emission factor for constant operation are used. Based on these assumptions, start, stop and constant operation emissions are calculated (see calculations criteria in the Data in Brief).

3.5.2. CO_2 equivalent emissions

CO_2 equivalent emissions are calculated according to emission factors shown in Table 3. The hourly power output is multiplied by the emission factor to obtain the emissions for each technology. For technologies with one single data series, TR and hydro, the power output of the technologies they integrate is assumed to be proportional to the percentage of participation in the total installed capacity, as described in Table 3.

3.6. Levelized cost of electricity (LCOE)

For nuclear, coal, CC, wind, and solar PV, the LCOE depends on their annual capacity factors in future scenarios. Therefore, for wind and solar PV the LCOE depends on curtailment. Fig. 5 shows how the LCOE varies considering 2030 scenarios.

For 2017, USD 0.06/kWh for wind [84] and USD 0.085/kWh [86] for PV with the European Central Bank's exchange are used to obtain the system costs [87]. For future projections, USD 0.03/kWh with a capacity

Table 5
Annual power generation by technology - historical data vs model.

Technology	Historical Generation (GWh)	%	Model generation (ROCOF 1.1 Hz/s) (GWh)	%	Variation (historical vs model) (%)[a]	Variation factor[b]
Wind	47 147	18.7	45 761	18.1	2.9	
Solar PV	7814	3.1	7814	3.1	0	
Solar Thermal	5282	2.1	5282	2.1	0	
Nuclear	55 604	22	60 831	24.1	−9.4	
Coal	42 752	16.9	39 183	15.5	8.3	
Combined-cycle	34 154	13.5	28 938	11.5	15.3	
Hydro	17 220	6.8	17 220	6.8	0	*Low*
PHS	0[c]	0.00	90	0.04	−0.04[d]	
CR	31 180	12.3	35 562	14.1	−14.1	
TR	3688	1.5	4289	1.7	−16.3	
PHS consumption	0[c]	0.00	−139	−0.05	0.05[d]	
Balearic Islands	−1161	−0.5	−1161	−0.5	0	
International Interconnections Balance	8994	3.6	8994	3.6	0	
Total generation balance (TG) or Final demand	252 667	100	252 667	100	–	–

The p-value (using a two-tailed test) is greater than 0.05, even close to 1 (p-value = 0.99936). The value of the t-statistic is 0.00081, while the t-critical value is 2.17881. Therefore, the difference is not statistically significant.

[a] The calculation has been carried out with all decimals. It can be interpreted as the relative error (between the historical and the model percentages).

[b] Qualitative factor assumed to evaluate the variation between the historical data and the model (0–25% Low, 26–50% Medium, 51–75% Medium / High, 76–100% High).

[c] Generation and consumption data by PHS are not presented since historical hydro shows (as a single data series) the annual generation balance (generation less consumption). The percentage corresponding to PHS has been discounted to be modelled in future scenarios.

[d] Because the historical value is 0, the result is shown as an absolute error.

Table 6
Installed capacity for Sustainable Transition 2030.

Technology	TYNDP Installed capacity (ST-2030) (MW) [40]	FEPPS Installed capacity (2030) (MW)
Wind	31 000	31 000
Solar PV	40 000	40 000
Solar Thermal	2300	2304
Nuclear	7117	7117
Coal	4660	4768
Combined-cycle	*24 560*	*35 613*[a]
Hydro	23 050	23 050
PHS	8280	8280
CR	8500	8500
TR	2550	2550

[a] FEPPS requires more installed capacity than TYNDP.

factor of 55% for wind [84] and USD 0.046/kWh with a capacity factor of 26% for PV [85] are used as references. These data and our capacity factor for 2030 allow obtaining wind and PV curves shown in Fig. 5. Nuclear, coal and CC curves were used from [83]. The LCOE used for the remaining technologies is presented in Table 4 since they do not significantly vary in their capacity factor.

4. Results and discussion

This section validates the FEPPS model with historical data, compares our base scenario ST with TYNDP ST-2030 projection and provides the results for our base scenario ST-2040 and DG-2030–2040, as well as those from GCA-2040. Although ST considers high penetration of VRE, it is the most conservative scenario in terms of technological and economic changes. Finally, the effects of inertia on the CO_2 Emission Factor and LCOE are provided.

4.1. Model validation

4.1.1. Demand power capacity and variables - model with historical data

The new installed capacities are equal to the historical ones for all technologies, except for the combined-cycle since it is an output from the model. The total installed capacity of 2017 was 98 877 MW, while that of the model is 95 786 MW. The annual energy demand for 2017 was 252 667 GWh, and the minimum power demand was 18 730 GWh. By introducing this minimum, the same historical demand time series is obtained.

The result indicates that 3091 MW less combined-cycle capacity is required in the model than in the selected year. The CC installed capacity obtained in the model was 21 856 MW, while the historical was 24 948 MW. The historical share of CC in total installed capacity was 25.23%, while in the model, it was 22.82%, giving a 9.6% historical variation (calculated as the relative error).

4.1.2. Power generation - model with historical data

Table 5 shows historical power generation, as well as modelled power generation with historical data.

As shown in Table 5, all technologies present a low variation factor. The technology with the most significant variation is TR (followed by CC, nuclear and coal). Annual generation from PHS should be zero as it was discounted from historical data and modelled to store the surplus generation. However, a low and non-significant variation was obtained. Wind also has a low variation due to curtailment, and the other technologies have no variation. Therefore, there is no statistically significant difference between the modelled and historical generation using a two-tailed test, as shown in Table 5.

The share of VRE in power generation was 21%, and the CC capacity factor does not show a significant variation (16% for historical value and 15% for the model). To a certain extent, variations in the current generation are included in the historical flexibility parameters. These variations are challenging to predict because of the large number of factors involved (e.g., scheduled shutdowns, real-time adjustment services or exceptional circumstances; that are not explicitly included in the model). Therefore, the power output distribution is a characteristic that the model cannot reproduce (frequency histograms of the power output of each technology are presented in the Data in Brief).

4.1.3. Curtailment and inertia results – model with historical data

There should be no curtailment or reductions in renewable energy when considering the historical installed capacities. From FEEPS, only 2.9% of wind power was curtailed due to the inflexible operation of conventional power plants. For 2017, it was also necessary to find the CIL (depending on ROCOF) where there are no power grid failures

Table 7
Annual power generation by technology TYNDP ST (82) vs model (2030).

Technology	Model with curtailment (ROCOF 1 Hz/s) (GWh)	TYNDP-ST (1982)[a] (GWh)	%	Model without curtailment (GWh)	%	Variation (TYNDP vs model without curtailment) (%)[b]	*Variation factor* [c]
Wind	44 817	64 512	22.9	63 762	22.6	1.2	*Low*
Solar PV[d]	47 270	80 289	28.5	75 698	26.9	5.7	*Low*
Solar Thermal[d]	5201	–	–	–	–	–	–
Nuclear	43 089	49 172	17.5	43 089	15.3	12.4	*Low*
Coal	9639	7133	2.5	9639	3.4	−35.1	*Medium*
Combined-cycle	43 327	43 660	15.5	35 022	12.4	19.8	*Low*
Hydro	21 352	28 654	10.2	23 466[e]	8.3	18.1	*Low*
PHS	1890						
CR	39 299	38 596	13.7	39 299	13.9	−1.8	*Low*
TR	8245	13 373	4.7	8245	2.9	38.3	*Medium*
Curtailment	–[f]	−71 978[g]	−25.9	−38 243[h]	−13.6	47.5	*Medium*
PHS consumption	−2671	–	–	–	–	–	–
Balearic Islands	−1480	–	–	–	–	–	–
International Interconnections Balance	21 760	29 261	10.4	21 760	7.7	25.6	*Medium*
Total generation balance (TG) or Final demand	281 738	281 764	100	281 738	100	–	–

[a] TYDNP Scenario ST-2030 (elaborated from the climatic variations of 1982- a drought year).
[b] It can be interpreted as the relative error.
[c] Qualitative factor assumed to evaluate the variation.
[d] Our results of solar PV and solar thermal are added to compare with TYNDP (which presents a single value for the two technologies).
[e] Data for hydraulic generation and pumped hydroelectric storage are added to compare with TYNDP (single value).
[f] Values already included in generation results.
[g] Assumed value, calculated by subtracting the generation from all sources (including exchange balances) minus the total generation balance.
[h] Value calculated by adding the curtailment (-34 091 GWh) plus the pumping consumption (-2671 GWh) and the Balearic link (-1480 GWh) values.

Table 8
Curtailment and reduction of renewables required by inflexible operation of conventional power plants (ST-2030).

Technology	Annual available power (GWh)	Curtailment (GWh)	Curtailment (%)
Wind	63 762	11 433	17.9
Solar PV	70 416	22 353	31.7
Solar thermal	5282	82	1.5
Hydro	21 576	224	1.0
Total	–	33 979	–

because of inertia constraints. The sensitivity analysis results show that 1.1 Hz/s and 70 227 MWs were the values in which there were no power grid failures. Therefore, it could be inferred that in 2017 the CIL was around 70 000 MWs, and its equivalent ROCOF (1.1 Hz/s) was the level against which the model results were compared with historical data (See Fig. 2-DIB for variations of the CIL according to ROCOF).

4.2. Analysis of the ST-2030 scenario

4.2.1. Inputs to the model

Table 6 shows the data retrieved from TYNDP 2018 and the installed capacities used in FEPPS.

For ST-2030, 7 nuclear power plants were considered, resulting in the same installed capacity as TYNDP. For coal, 13 power plants were

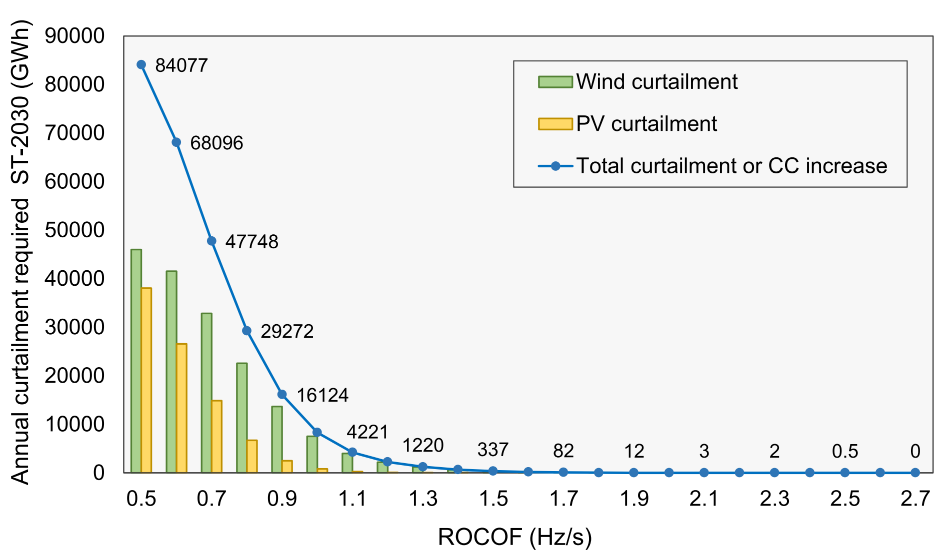

Fig. 6. Annual curtailment required for system stability for different ROCOF levels (ST-2030). Table 24-DIB contains the curtailment required for stability for each technology. The total VRE curtailment is equivalent to the CC increase.

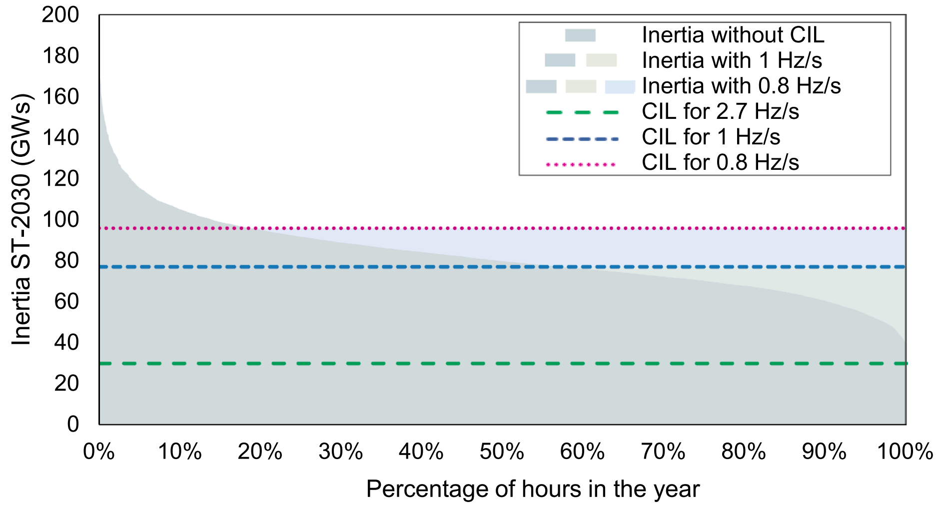

Fig. 7. Inertia duration curves for ST-2030.

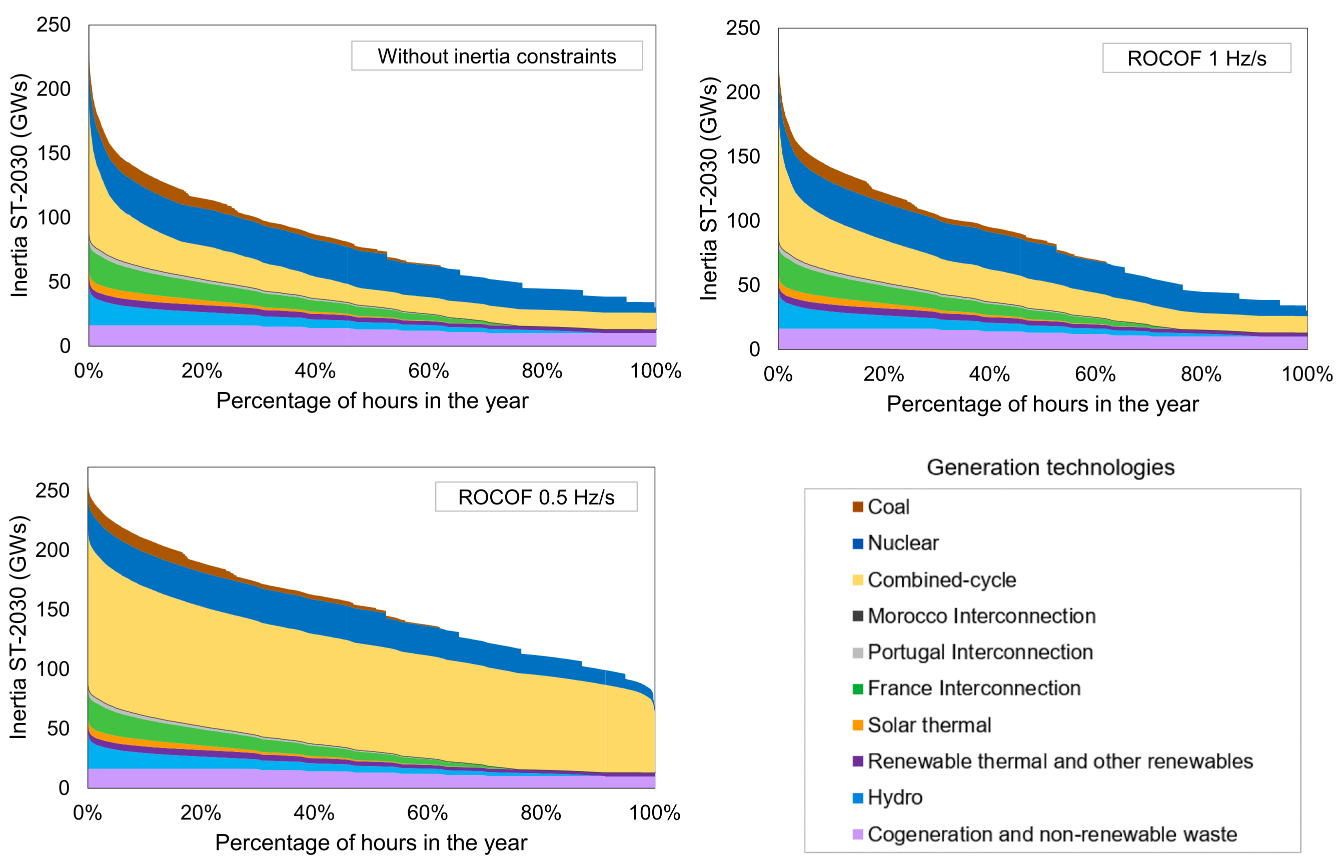

Fig. 8. Synchronous generation according to different ROCOF levels by ST-2030.

considered to obtain an installed capacity close to TYNDP. The total installed capacity in TYNDP is 152 017 MW, while that of the model is 163 182 MW. Demand, and therefore the net power generation for TYNDP is 281 764 GWh [40]. A minimum demand of 20 885 MW was considered in the model, resulting in a total demand of 281 738 GWh (close to TYNDP). The values of the variables used in the model are in the Data in Brief. The CC installed capacity in TYNDP is 24 560, while that required in the model is 35 613 MW. Therefore, the results show a need for the CC installed capacity of 11 GW more when comparing with the historical (2017) and TYNDP values.

4.2.2. *Power generation*

Table 7 shows the annual model generation and TYNDP generation for ST-2030.

The model results cannot be directly compared with TYNDP since a single value for curtailment, pumping consumption, and the Balearic link was assumed for TYNDP (subtracting the generation of all sources minus the generation balance or demand). Therefore, Table 7 presents the gross generation data of the model without curtailment, and, consequently, the most significant variation occurs in that comparison. Coal, TR, International Exchanges also have medium variation factors, while the rest are not significant. PHS is the most mature and flexible

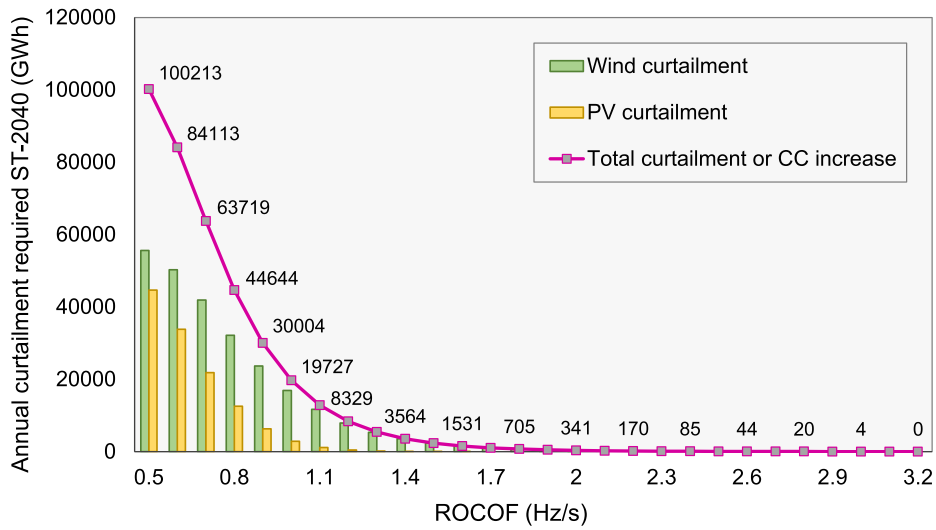

Fig. 9. Annual curtailment required for system stability for different levels of ROCOF (ST-2040).

Table 9
Comparison of estimated and calculated CO_2 equivalent emissions of the power sector for 2030 and 2040 [5,28]

Source (target / methodology used)	Scenario	Emissions 2030		Emissions 2040	
		(Mt)	($kgCO_2$/MWh)	(Mt)	(kg CO_2/MWh)
Global Target	Paris benchmarks	–	75–80	–	~0
Estimated values in Spain (National targets)	PNIEC (sustainable transition)	43	158[a]	–	–
	PNIEC (target scenario)	20.6	67[a]	–	–
Calculated values using FEPPS (1 Hz/s) and emissions from all technologies	ST	41	157	41	159
	GCA	–	–	37.7	153
Calculated values using FEPPS and REE methodology (i.e., excluding renewables, nuclear and CC operating mode)	ST	36	128	36	126
	GCA	–	–	32.5	121

[a] Value calculated from generation and emissions reported in PNIEC.

Table 10
Installed capacities for DG-2030–2040 and GCA-2040.

Technology	DG-2030 (MW)	DG-2040 (MW)	GCA-2040 (MW)
Wind installed capacity	31 000[a]	35 873[a]	50 998[a]
Solar PV installed capacity	47 157[a]	66 906[a]	77 000[a]
Combined-cycle Installed capacity	44 632[b]	57 150[b]	53 187[b]
Share of VRE in generation (%)	34	37	39
Total curtailment (%)	16	23	44

[a] Value taken from TYNDP.
[b] Calculated in the model.

storage technology [92]. However, the model cannot use it freely since mixed PHS depends on weather conditions. Although PHS installed capacity increases by around 5 GW, its share is not significant (0.65%) due to drought.

The share of VRE in power generation was 33%. CC reached a low variation, with an annual capacity factor of 14%, closer to the historical value (16%). TYNDP has a 20% annual capacity factor for this scenario. The maximum CC capacity factor reached in one hour in our scenario was 61%, while in 2017, it was 57%. Assuming an installed capacity (22 200 MW) to reach TYDNP's annual capacity factor of 20%, our maximum capacity factor in one hour would be 98%. Therefore, if the installed capacity does not increase, CC power plants should be forced to reach capacity factors higher than those recorded historically. If not possible, this increase represents an opportunity for new flexible technologies.

4.2.3. *Curtailment and inertia results*

4.2.3.1. Curtailment required by inflexible operation of conventional power plants. From the levels in Table 1, curtailment and reduction in GWh for ST-2030 are obtained (Table 8).

According to the model, the curtailment required for ST 2030 is approximately 18% and 32% of wind and solar PV availability, respectively. This curtailment occurs due to the increase in renewables since it is not possible to reduce generation from conventional sources (technical restrictions). Solar thermal and hydro reductions are considered disregarded as they represent less than 2% of their annual availability.

4.2.3.2. Curtailment required for system stability. After performing the sensitivity analysis for ST-2030, the system does not show power grid failures for 1 Hz/s. Besides, the system does not require curtailment due to inertia for a level greater than or equal to 2.7 Hz/s (CIL 29 823 MWs), as shown in Fig. 6. With a ROCOF level greater than or equal to 2.7 Hz/s, the system's synchronous generation is enough to meet the required inertia level without the need for curtailment.

Fig. 7 shows the inertia duration curve for ST-2030 with 1.2 Hz/s, 0.8 Hz/s, and without applying restrictions, including the CIL. As the ROCOF decreases, the CIL increases with the need for synchronous generation (resulting in higher curtailment).

The increase in synchronous generation can be seen in Fig. 8. The CC capacity factor is 11%, and the annual generation 35 022 GWh without applying any inertia constraint. However, the capacity factor increases to 14% and the total generation to 43 327 GWh for 1 Hz/s. The total VRE curtailment (inflexible operation + stability restrictions) is 42 090 GWh (15% of annual generation) for 1 Hz/s. In the extreme case of assuming 0.5 Hz/s, the CC capacity factor rises to 51% (158 774 GWh generation) and the total curtailment to 117 862 GWh).

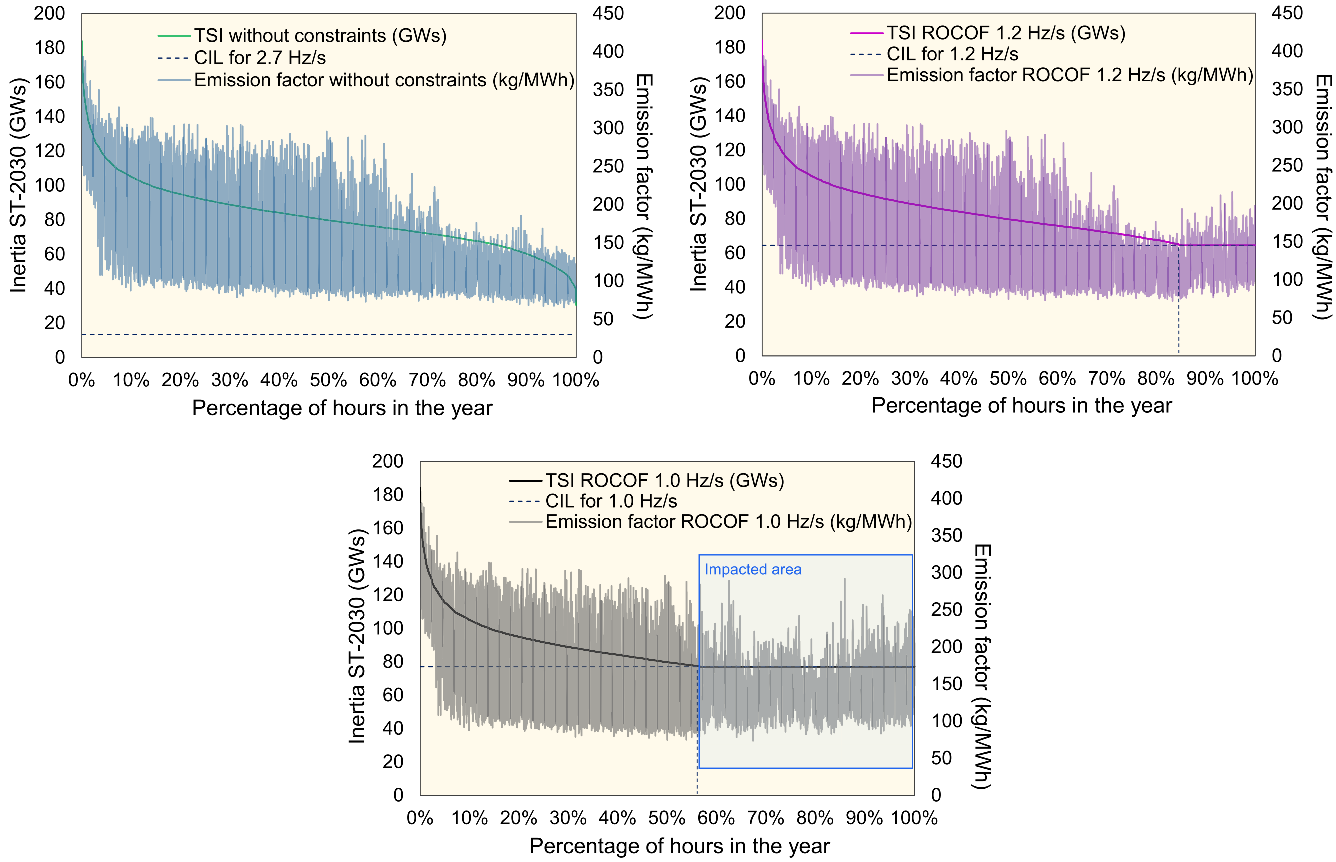

Fig. 10. Inertia vs Emission Factor in scenario ST-2030. The figure shows the inertia duration curves in the year and how the emission factor of the power system is affected by stability constraints. With 1.2 Hz/s, a percentage of hours in the year is impacted (higher emissions are obtained with higher combined-cycle generation). With 1 Hz/s, higher CO_2 emissions are reported, and the impacted area is more significant because the CIL the system must meet is higher than in the 1.2 Hz/s case.

Without inertia constraints in 2017, 741 254 GWs of inertia was enough to meet the CIL. For ST-2030, the TSI without inertia constraints was 717 348 GWs. The TSI decreases compared to 2017 due to the increase in VRE. Also, it should be noted that ST is the most conservative in terms of VRE increase. According to ENTSO-E, the current power system cannot withstand imbalances with a ROCOF greater than 1 Hz/s. It also indicates that, although simulations for the future ask for a capability to handle a frequency gradient of 2 Hz/s, improvements will be needed in the generation performance and load shedding [64].

4.3. Analysis of 2040 scenarios

For the ST-2040 base scenario (1 Hz/s; no power grid failures), the results show a need of 48 340 MW, i.e., an additional 13 GW compared with the 2030 base scenario (24 GW compared with TYNDP). The capacity factor is 16%. If we consider the same installed capacity as TYNDP, the maximum capacity factor required in one hour is 124%. Therefore, the installed capacity would be insufficient to balance the power system. It should be noted that this scenario does not have coal generation and the installed nuclear power is reduced to 3050 MW. The detailed inputs and results for 2040 are provided in the Data in Brief.

The percentage of VRE in power generation was 35%. The CC generation without inertia constraints (or ROCOF greater than or equal to 3.2 Hz/s) is 48 077 GWh (TSI 641 077 GWs due to the significant reduction of conventional technologies). Nevertheless, with 1 Hz/s or 0.5 Hz/s, synchronous generation requirements (or CC increase) would be 19 727 GWh and 100 213 GWh, respectively (see Fig. 9). The total curtailment of VRE of the base scenario would be 72 164 GWh, which represents 23% of the annual generation. It should be noted that 1 Hz/s is a level that the Continental European power system can withstand [64].

4.4. Analysis of CO_2 emissions and systems costs for ST-2030 and ST-2040 scenarios

4.4.1. Emissions analysed with the REE methodology

REE emission factors were considered to compare the emissions obtained in the scenarios. REE emission factors are 950 $kgCO_2$/MWh for coal, 370 $kgCO_2$/MWh for CC and 280 $kgCO_2$/MWh for CR. For 2017, 58 Mt CO_2 were obtained. For 2030, 36 Mt CO_2 were obtained for the model and 34 Mt CO_2 for TYDNP (using these factors). For 2040, 36 Mt CO_2 and 28.5 Mt CO_2 were obtained, respectively. Higher emissions are obtained in our scenarios due to the higher coal and CR generation in 2030 and CC in 2040. Emissions reported in TYNDP 2018 are lower [40] because they depend on the assumed CO_2 price, which can result in higher or lower emissions [93].

4.4.2. Emission with flexible CC operation mode and CO_2 equivalent emissions from all technologies

If the flexible CC mode of operation is included, there is an increase in the annual emission factor of 2017 from 229 $kgCO_2$/MWh (REE methodology) to 230 $kgCO_2$/MWh. The emissions increase to 241 $kgCO_2$/MWh (weighted average) by including the other technologies (nuclear and renewables). For ST-2030, the emissions increase from 128 $kgCO_2$/MWh to 132 $kgCO_2$/MWh and 157 $kgCO_2$/MWh (weighted average) and for ST-2040, from 126 $kgCO_2$/MWh to 132 $kgCO_2$/MWh and 159 $kgCO_2$/MWh. Therefore, the increase is not significant after applying this methodology, but it grows when considering all

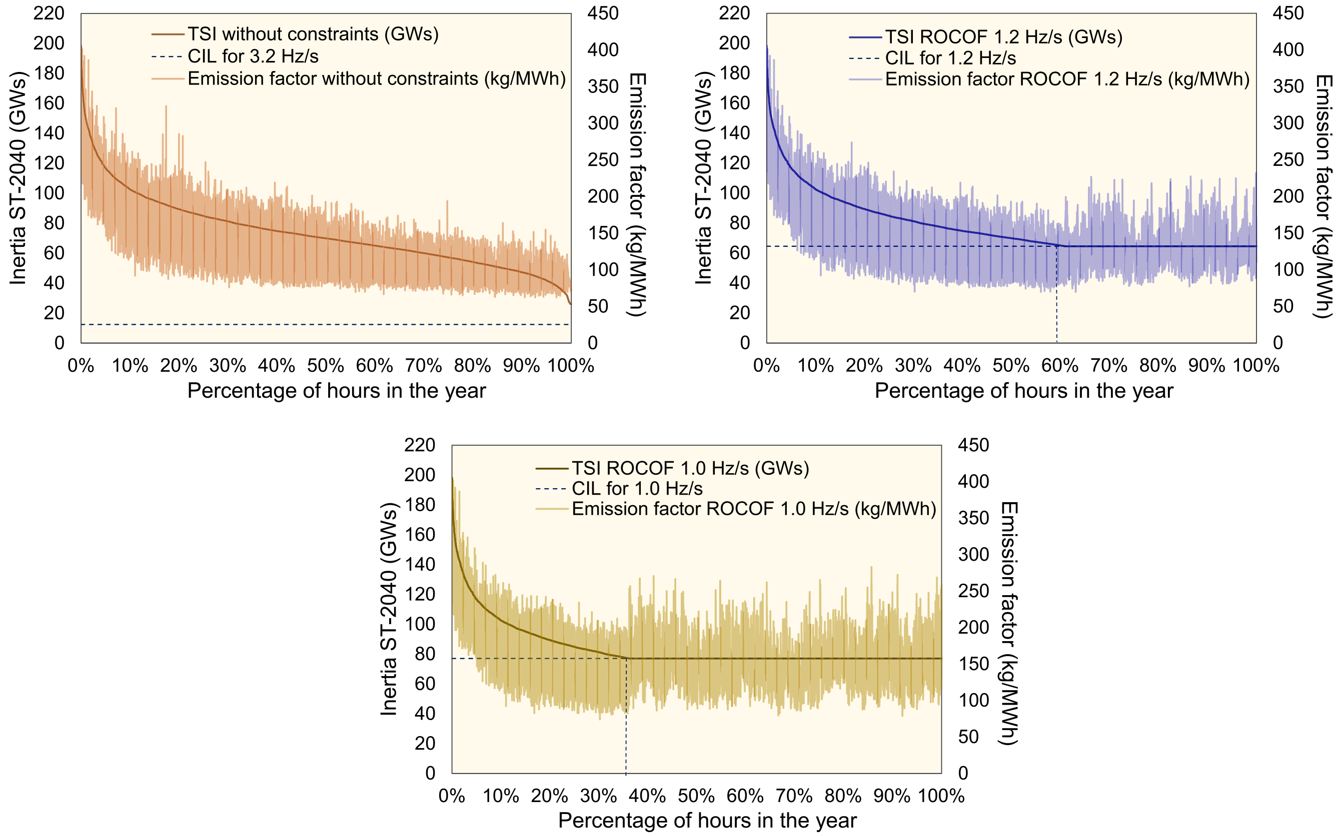

Fig. 11. Inertia vs Emission Factor in scenario ST-2040.

technologies, requiring greater CC flexibility, and rising emissions. It should be noted that only flexible CC was analysed as it is the technology that balances the system (there would be higher emissions considering the operation mode for the rest of the technologies).

Table 9 shows the PNIEC projected emissions by 2030 for two scenarios, sustainable transition and target [28]. It also shows the Paris benchmarks and our results. As can be seen, the emissions obtained in FEPPS by 2030 and 2040 base scenarios would be far from the emissions of the PNIEC targets and Paris benchmarks, even without considering the CO_2 equivalent emissions and the CC operating mode.

4.4.3. System costs

The LCOE obtained (as a weighted average) was 68 €/MWh for 2017, 80 €/MWh for ST-2030, and 92 €/MWh for ST-2040. Therefore, despite the increase in renewable energies, the LCOE increases due to low VRE capacity factors (see Fig. 5). By 2030 the capacity factor of coal and nuclear also decreases, increasing the LCOE.

CC capacity factor increases from 2030 to 2040, decreasing its LCOE. However, as shown in Fig. 5, although the capacity factor rises significantly, the LCOE reduction is less than for the rest of the technologies. It is worth mentioning that an increase in the CC LCOE is expected because of the rising natural gas prices, increasing operating costs [94]. The emissions and system costs obtained for each technology and scenario are included in the Data in Brief.

4.5. Analysis of other scenarios (DG-2030, DG-2040 and GCA-2040)

For DG and GCA scenarios, simulations were made for 1 Hz/s, 1.2 Hz/s and no inertia constraints. The installed capacities for DG-2030 are the same as for ST-2030, except for solar PV. The installed capacities for wind and solar PV increase for DG-2040 and GCA-2040 scenarios (the installed capacities of the other technologies are in the Data in Brief). The share of VRE in power generation and the curtailment are shown in Table 10. Although the installed capacity of VRE increases, without the availability of storage options other than PHS, these technologies would be used with low-capacity factors, especially solar PV, reaching a capacity factor of only 8% for the GCA-2040 scenario (ROCOF 1 Hz/s).

4.6. Analysis of the impact of inertia on the CO_2 emission factor and LCOE for all scenarios

This section presents the impacts of considering different levels of ROCOF on the CO_2 emission factor and the LCOE in the power system (for more detailed results of this section, see the Data in Brief).

4.6.1. Impact of inertia on the CO_2 emission factor

The effects of applying 1.2 Hz/s, 1 Hz/s and without considering restrictions on the emission factor for ST-2030 are shown in Fig. 10. Peak emissions occur with the highest inertia contribution levels, while moderate and low emissions occur with lower TSI. The emission factor is 144 kg CO_2/MWh without restrictions; however, after applying 1.2 Hz/s and 1 Hz/s, the CIL raises and the emission factor increase to 148 and 157 kgCO2/MWh, respectively. The impacted area is due to the higher CIL that the system has to meet (increasing the CC). In these areas, the emission factor increases by 22% for 1.2 Hz/s and 27% for 1 Hz/s. For DG-2030, the emission factor in this area increases by 17% and 27%, respectively.

In Fig. 11, after applying 1.2 Hz/s and 1 Hz/s, the emission factor increases from 129 to 142 and 159 kgCO_2/MWh, respectively. In the affected areas, the factor increases by 33% for 1.2 Hz/s and 45% for 1 Hz/s. For DG-2040, the factor increases 25% and 36%, and for GCA-2040, 40% and 54%, respectively.

The increase in the emission factor due to the increase in inertia constraints is more significant in ST and GCA than in DG. In DG, due to the considerable rise in PV and the reduction mainly of coal, the inflexible CC has high participation before the inertia constraint is

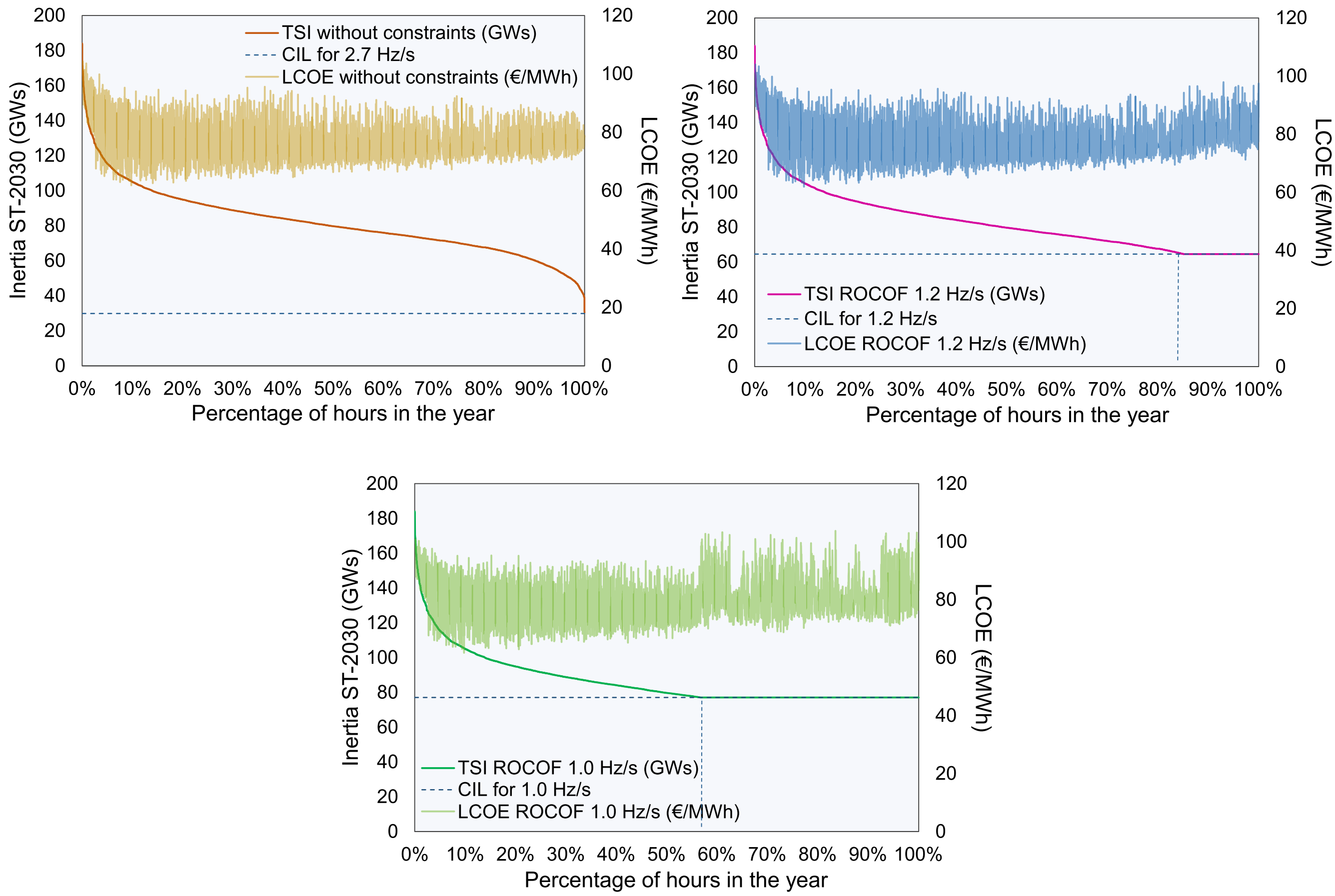

Fig. 12. Inertia vs LCOE for scenario ST-2030.

applied (providing high inertia). It should be noted that with scenarios with a ROCOF lower than 1 Hz/s, both the emission factors and the LCOE would increase even more because of the increase in synchronous generation necessary to reach CIL. The affected area is more significant in 2040 than in 2030. Therefore, with a higher share of VRE and lower conventional sources, there is less TSI in the system and higher pressure to cover the CIL, increasing emissions. This effect is more significant for the GCA scenario.

4.6.2. Effects of inertia on the LCOE

Fig. 12 shows the effect on the LCOE of applying 1.2 Hz/s, 1 Hz/s and without considering inertia constraints for ST-2030. Without inertia constraints, peak LCOE occur with the highest inertia contribution levels, and the LCOE is 77 €/MWh. After applying 1.2 Hz/s and 1 Hz/s, the CIL raises and the LCOE increases to 78 €/MWh and 80 €/MWh, respectively. In the impacted areas, the LCOE increases by 7% and 8%. For DG-2030, the LCOE in these areas increases by 5% and 8%.

In Fig. 13, for ST-2040, the LCOE increases from 83 €/MWh to 86 €/MWh and 88 €/MWh, respectively. Therefore, the impact is more significant than in ST-2030. In the affected areas, the factor increases by 9% and 12%. The increase in the LCOE due to inertia constraints is more significant in ST and GCA than in DG, and the affected area is more significant in 2040 than in 2030. Despite the VRE increase, the LCOE increases because of high levels of curtailment. For DG-2040, the factor increases 5% and 9%, and in GCA-2040 6% and 11%.

The maximum and minimum LCOE and the frequency of values greater than 85 €/MWh[3] [95] for each scenario are in the Data in Brief.

[3] Value taken from [95] as a reference of an LCOE that allows to remain on track to decarbonisation towards 2030 for new builds.

The highest LCOE levels were obtained in GCA. The frequency of LCOE levels greater than 85 €/MWh during the year reaches significant results (greater than 60%) in ST-2040 (1 Hz/s), DG-2040 (1 Hz/s) and for all GCA-2040 scenarios, reaching 97% for 1 Hz/s.

Fig. 14 shows the mean emissions obtained for the different scenarios according to the share of renewables and the LCOE. It also includes Paris benchmarks for the EU power sector [5]. As can be seen, it is not possible to reach the emission levels contemplated in Paris or TYNDP even without considering curtailment or inertia constraints in the model. In the best scenario (in terms of emission reductions), 141 $kgCO_2/MWh$ is reached (DG-2030), far from the 80 $kgCO_2/MWh$ established in Paris. Regarding the effects of considering an inertia constraint for GCA-2040, the impact is more significant than in other scenarios since the emission factor increases from 115 (without restrictions) to 153 $kgCO_2/MWh$ (1 Hz/s), the LCOE rises from 91 to 102 €/MWh, and the percentage of RES drops from 61% to 52%.

Emissions do not drop significantly despite the significant increase in VRE. There is even a slight upward trend, and this is due to the role of flexible CC power plants in the balancing and stability needs. While emissions do not fall, it can be seen how the LCOE rises significantly (due to curtailment). Fig. 14 shows that, up to 35% of VRE generation (49% renewables) in ST-2040, the system does not show a significant increase in LCOE (€ 89/MWh). However, when it goes to 39% (52% renewables) in GCA, it reaches € 102/MWh. Therefore, to meet Paris targets in the selected Member State, in scenarios with more than 39% of VRE generation, the system would need technologies with emission factors below 113 $kgCO_2/MWh$ (which allows meeting the Paris benchmark of 80 $kgCO_2/MWh$ through a weighted average). Moreover, these technologies would need a maximum LCOE of € 134/MWh (which allows reaching € 102/MWh of GCA scenario through a weighted average) and an inertia contribution similar to that of the combined-cycle power

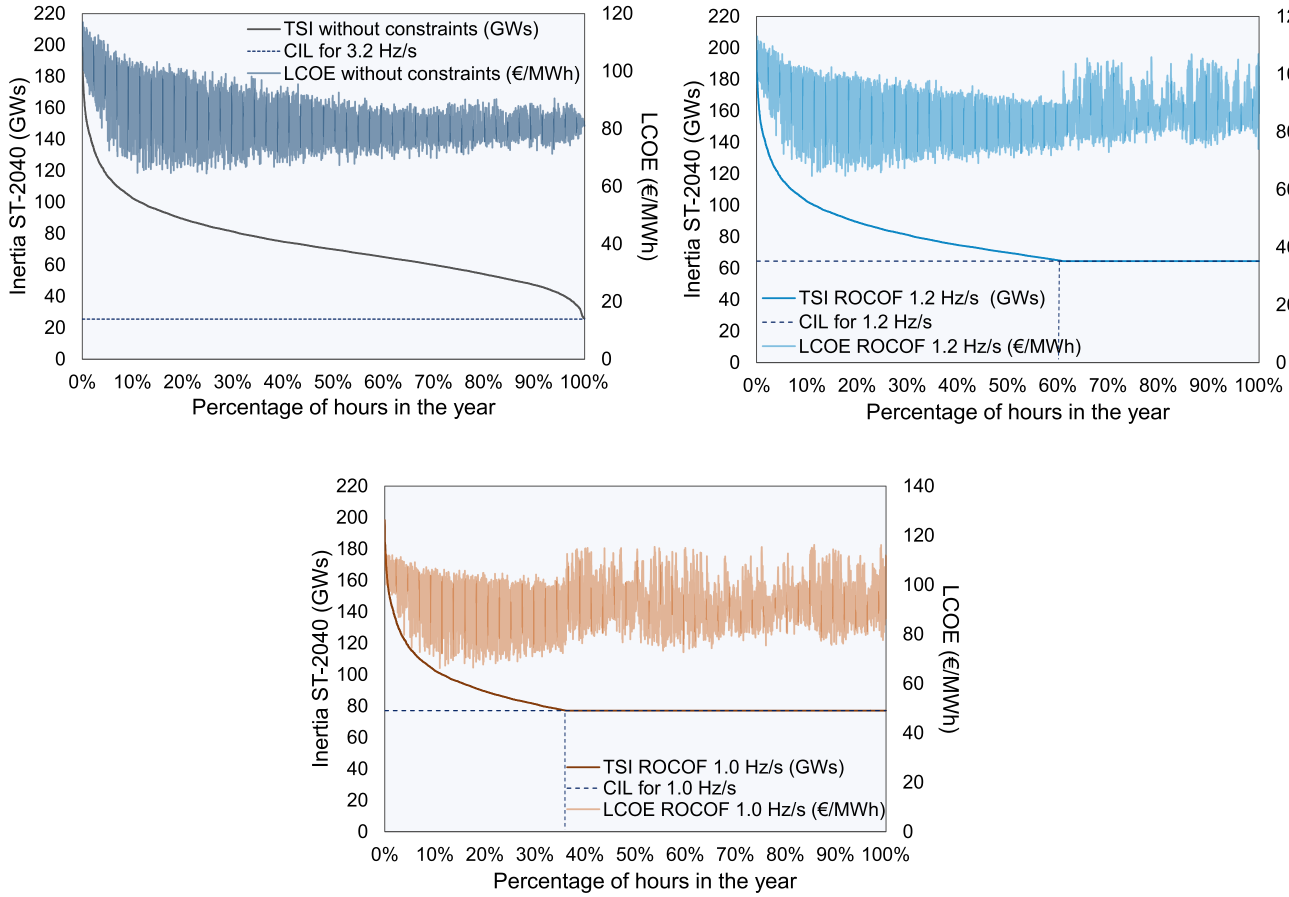

Fig. 13. Inertia vs LCOE for scenario ST-2040.

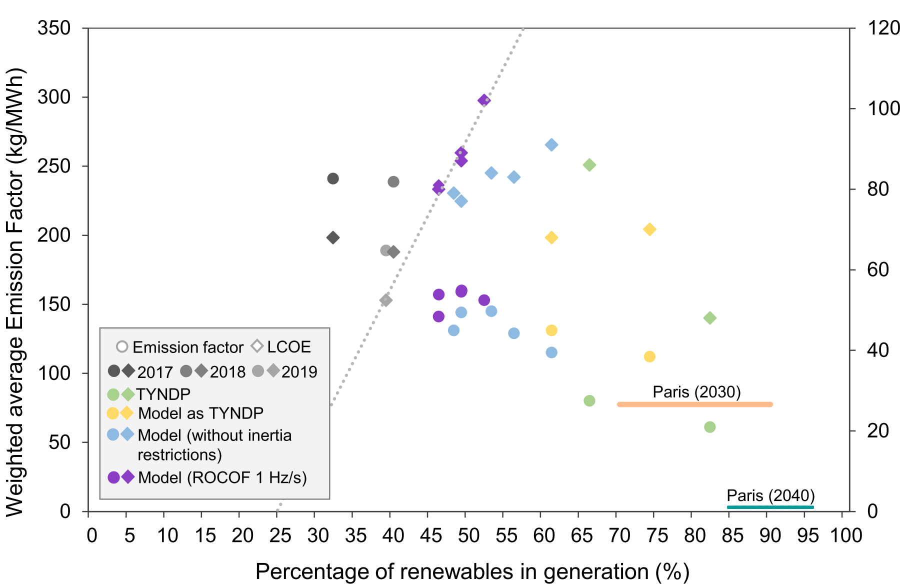

Fig. 14. Results of LCOE and Emission Factor with and without inertia constraints. The figure shows how emissions do not fall significantly with the increase of renewables in the base scenarios (1 Hz/s) while the LCOE tends to increase significantly (see trendline). The highest LCOE is for the GCA-scenario (102 €/MWh and emissions just fall to 153 kgCO2/MWh, despite de increase in VRE). It also shows that without considering inertia constraints, emissions fall more than in base scenarios. Without considering neither flexibility nor inertia constraints (Model as TYNDP), emissions come a little closer to the Paris targets.

plants (5 s). The figure shows values for 2030 and 2040 scenarios, and the detailed results are found in sections 1.2.4-DIB and 1.2.5-DIB.

If we consider the same GCA scenario but with 1.2 Hz/s, the system is less restrictive, and new technologies should have an emission factor of 136 kgCO2/MWh and a maximum LCOE of € 146/MWh. That means that higher ROCOF levels are considered, the less restrictive the system is. However, the current power system cannot withstand imbalances greater than 20% (1 Hz/s). Nevertheless, future simulations with a ROCOF of 2 Hz/s (in the range of 40% for maximum imbalance) are based on system improvements such as development plans and related dynamic system studies [64]. Therefore, with greater ROCOF levels, the power system needs improvements in the generation performance and load shedding (as indicated in section 4.2.3) to reduce the risk of system split [64]. That is especially important for Spain since it may experience higher ROCOFs in the future due to its low interconnection capacity.

Other studies have found that flexibility requirements increase considerably in electricity systems with a total energy contribution of more than 30% of VRE, leading to increased costs and high levels of curtailment [8,96]. In addition, it is necessary to determine the actual feasibility of power systems considering stability and transmissions [8]. Studies consider that the reduction of inertia in frequency stability is the main challenge in power systems, as it reduces the ability of the system to withstand power imbalances [18].

PHS does not have a significant role in this study, which has already been agreed upon in previous studies [21]. Consequently, for power systems with a high share of VRE, it may be necessary to have additional energy storage technologies. These technologies might be able to reduce curtailment and replace the CC considering the decarbonisations targets. Battery energy storage systems (BESS) could be regarded as an option to increase flexibility (short-term duration). Moreover, long-term storage technologies such as hydrogen and Power to Gas (P2G) are considered potential options to meet the storage needs in systems with very high shares of VRE [21].

This paper aimed to find the characteristics that "new technologies" should have (including energy storage) in the future power system. This study sets the ground scenario of the resulting curtailment and flexibility needs if only current technologies were used. Therefore, we have not included new storage technologies. From here, future studies could replace fossil generation with new technologies that meet the required flexibility without compromising system inertia and considering the economic and environmental performance.

5. Conclusions

This study proposed a new power system model (FEPPS) that allows replicating and predicting the power system behaviour through flexibility and stability requirements as VRE increases. It improves the identification and quantification of the main challenges in the selected power grid, which are usually not well defined in national and international scenarios.

Using the historical and the forecast scenario for Spain by 2030 as a reference example, the model predicts an additional CC installed capacity of 11 GW (43% increase from 2017) to provide flexibility and stability. The estimated VRE generation (33%) is significantly lower than that forecasted by national and international organisations (approx. 50%) for 2030. When considering 2040, 13 additional GW of CC are needed, while VRE generation raised only up to 35% (compared to approx. 67% forecasted). The identified inconsistencies are influenced by higher curtailment than those previously identified when flexibility and stability requirements were not considered. The differences in CC installed capacities are related to moderate-to-high curtailment levels. The estimated curtailment will be 15% and 26% for 2030 and 2040, respectively. Altogether, the LCOE will be 15% and 24% higher for 2030 and 2040 (compared to 2017), respectively.

Regarding the environmental performance of electricity generation, additional inconsistencies are identified. The high flexibility (operation mode) of CC as well as the estimation of the climate impact of nuclear and renewables, contribute to a moderate increase in CO_2 equivalent emissions (157 $kgCO_2$/MWh for 2030 and 159 $kgCO_2$/MWh for 2040). Together with the impact of lower VRE generation, emissions obtained are well above the targeted value in Paris, and there is no significant difference for the 2030 and 2040 scenarios. As a result, with 55% of VRE installed capacity and 39% share in the annual generation, the power grid experiences a significant rise in LCOE without a drop in emissions. Therefore, it is not possible to reach the emissions forecasted by national and international scenarios. To meet Paris targets, generating technologies with emission factors below 113 $kgCO_2$/MWh, a maximum LCOE of 134 €/MWh, and inertia constant of at least 5 s would be required. The identification and efficient incorporation of such technologies are crucial for the decarbonisation of the power system.

CRediT authorship contribution statement

K. Guerra: Methodology, Investigation, Formal analysis, Data curation, Software, Writing – original draft. **P. Haro:** Conceptualization, Methodology, Supervision, Validation, Visualization, Writing – review & editing. **R.E. Gutiérrez:** Data curation, Visualization, Investigation. **A. Gómez-Barea:** Writing – review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Datasets related to this article can be found at https://doi.org/10.7910/DVN/R2IVYN, a free data repository hosted at Harvard Dataverse (Guerra, Karla, 2021).

Appendix A

International interconnections in AC and DC

Interconnection with France

Until September 2015, Spain had an exchange capacity of 1400 MW [48]. In October 2015, the capacity was doubled up to 2800 MW with a HVDC line instead of AC, used in the previous transmission networks [48]. Furthermore, by 2025 the capacity will increase to 5000 MW (DC) [49]. There are also two projects [97] to reach 8000 MW through DC by 2030 [50] and 9000 MW by 2040 [42]. It should be noted that the technology available in the existing and expected interconnections with France is Voltage Source Converter (VSC) HVDC. This technology behaves similarly to synchronous generators and is able to provide inertial response such as primary and secondary frequency control [20]. For projections, the contribution (%) of each technology in generation for France and Portugal was obtained from TYNDP [40] (Data in Brief). With these values and the rotational inertia constants of the technologies, we get the rotational inertia constant of the interconnection through a weighted average.

It is not possible to have the electricity mix of imported power from France for 2030 and 2040. Accordingly, the inertia contribution was calculated by multiplying the instantaneous power by the corresponding rotational inertia constant.

Interconnection with Portugal

For Portugal, an increase in capacity for 2030 for export and import (4200 MW and 3500 MW) is expected. By 2040, higher capacities are expected (4700 MW and 4000 MW). These data correspond to all projects commissioned before 2035 following the TYNDP 2018 [42]. The existing and scheduled interconnection lines between Spain and Portugal are AC lines. The same method for France to obtain the inertia constant and contribution was used.

Interconnection with Morocco

Spain is interconnected with Morocco through two submarine cables of AC with a total capacity of 1400 MW [51]. In [98], a third AC cable is considered by 2026 (each with a capacity of 700 MW) with a total exchange capacity of 1500 MW (margin of system support) [98].

Interconnection with the Balearic Islands

There is a 400 MW HVDC submarine connection with the Balearic Islands. Therefore, it is not considered in the inertia analysis also considering that the interconnection is only from Spain to the Islands [53]. Between Majorca and Ibiza, Ibiza and Formentera and Menorca y Majorca there are HVAC links [54 55]. In this way, the peninsula covered 28% of the Islands' total demand in 2019 [56]. In this study, the capacity (adding with the peninsula and between them) was assumed to be 727 MW [53,54,99]. An increase in the interconnection between Ibiza and Formentera and Majorca and Menorca is envisaged [55,57,100]. Therefore, if we consider an increase to 927 MW, we assumed that the peninsula would cover 35.7% of the Islands total demand for future projections.

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