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Inclusion of frequency control constraints in energy system investment modeling

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ABSTRACT

This study investigates how the inclusion of frequency control constraints in electricity system modeling impacts the levels of investment and dispatch in electricity generation and storage technologies for futures that include high-level penetration of variable renewable energy. This is achieved using a linear cost-minimizing investment and dispatch model using historic load, wind and solar conditions from Spain, Ireland, Sweden and Hungary for Year 2050. With an hourly time-resolution, constraints are added so as to ensure that, within each hour, sufficient inertial power and reserves are available to control the frequency of the power grid. Comparing the results obtained with and without these constraints reveals that the main impacts on the results are from battery investments and operation. Furthermore, it is found that the reserve requirements exert a greater impact on system composition and operation than do the inertial power requirements.

1. Introduction

Variable renewable energy (VRE) sources, such as wind and solar PV, are projected to provide a substantial proportion of our electricity if we are to meet climate targets. Given the non-dispatchable nature of these energy sources, their increased deployment will also increase the need for variation management strategies (VMS) for efficient integration of VRE, thereby maintaining its value with increasing share. Examples of VMS are the strategic use of batteries, hydrogen storages and power-to-heat systems, as well as flexible combined heat and power plants [1]. However, the transition to VRE-dominated power systems adversely affects the conventional mode for controlling the frequency of the power grid. Conventional grid frequency control relies on the mechanical inertia in synchronous generators to dampen and decelerate fluctuations. However, the dominant wind turbine type (variable speed) is interfaced through converters, as are all solar PVs, and thus does not provide synchronous inertia. Thus, the transition to VRE carries with it the risk of a level of synchronous inertia that is insufficient to secure frequency stability. In addition to reduced synchronous inertia, operating reserves (ORs) can also be adversely affected when dispatchable power plants are replaced by VRE [2].

Since both inertia and OR are vital to power system operation and may be adversely affected by a transition to VRE, various power engineering tools that simulate the physical principles and relationships have been used to study how frequency deviations could be managed in future systems [3,4,5,6,7,8] and more). However, the tools used to simulate frequency responses are unable, due to limitations linked to model complexity and purpose, to optimize the system in terms of generation capacity and dispatch on a system level.

To study how new technologies and constraints affect cost-optimal generation capacity and dispatch, several energy systems models have been developed with varying levels of detail in terms of temporal resolution and span, as well as operational constraints, geographic scale and technology representation [9,10,11,12,13,14]. Some of these models have been used to study the system impact of constraints on reserve capacity [15,16] and inertia [17]. Other studies have included constraints on inertia or reserves but have not explicitly studied them [10,18,19]. Nonetheless, studies

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investigating how inertia and reserves impact the cost-optimal system composition in future carbon-neutral electricity systems with high shares of VRE are lacking. In particular, there is a need to investigate the extent to which strategies aimed at managing the variability of wind and solar PV can be deployed to provide frequency control and ORs. Thus, it is unclear as to: 1) what the cost of providing these services will be in future carbon-neutral systems; 2) how these services will be provided; and 3) how their provision will affect the cost-optimal system composition.

This study imposes constraints regarding the intra-hourly operational reserve and inertial power capacity on the electricity system model described previously [9]. The model minimizes total system cost through linear optimization of both investments and operation, on an hourly time-scale with a time horizon of 1 year. The combination of one full year and hourly resolution makes the model suitable for studying the interactions between generation technologies and VMS, including strategies for short-term balancing of generation and load, as well as options for multiday and seasonal storages. A list of the included VMS and generation technologies is provided in Table 2. The model, on a technology level, includes operational constraints such as ramping, part-load and start-up, all of which have been demonstrated by Ref. [15] to be important when analyzing the requirement for reserve capacity and the value of energy storages. The model only studies one region at a time, and does not include inter-regional transmission. Thus, the results are primarily relevant to understanding the interactions between intra-regional electricity generation technologies and VMS, rather than to suggest appropriate electricity system compositions for actual regions or countries.

This study aims to investigate how the demands of inertia and OR in various system contexts affect the investments and operation of generation and storage technologies, as well as the total system cost, through cost-minimizing linear optimization. Special attention is paid to synergies between VMS and the provision of ancillary services. In addition, the consequences of *not* allowing inverter-interfaced technologies to provide synthetic inertia are investigated.

2. Methodology

In order to investigate how constraints imposed on inertia and OR influence the cost-optimal investments and dispatch in various system contexts, the principles underlying these constraints must be understood. This section focuses on the formulation of these constraints, the optimization model in which they are implemented, as well as the investigated system cases.

2.1. Inertia

While conventionally expressed in terms of GWs or MWs [20], the inertia is, in this work, expressed in terms of the power needed to cope with a dimensioning fault (N-1). This is to avoid inertia time constants (H) for technologies that provide synthetic inertia, and to facilitate comparisons with the provision of fast frequency reserves (FFR). While FFRs are not explicitly studied in this work, the synthetic inertia is implemented such that it can be considered as an FFR when delivered from batteries. The assumed H-values are based on [20]; and can be found in Table 1, along with the resulting increased power output during a dimensioning fault. The latter was calculated using Eq. (1) and the inertia constant, so as to keep the rate of change of frequency below 2 Hz/s, which is:

$$\frac{2H}{f} * \frac{df}{dt} = -\Delta P \tag{1}$$

where H is the inertia constant, f is the nominal frequency of the grid, and ΔP is the change in power output from the generator.

In addition to the technologies shown in Table 1, batteries, flywheels and wind power are assumed to be able to provide inertial power response (synthetic inertia) and contribute to the total system inertia. While batteries and flywheels can contribute as much as their capacities allow, wind power is assumed to limit its contribution to an additional 13% of the current production, in order to avoid significant recovery effects [based on the findings of [21]]. Hydrogen storage systems are assumed to be too slow to provide power for inertia responses owing to the nonsynchronous nature and the need for mass transportation to function, although they can provide reserve power.

For every time-step, the total available inertia response needs to at least cover the dimensioning fault (N-1). These values are further explained, and listed in Table 6, in the Cases section.

Table 1
Assumed inertia constants and resulting power response per technology type for synchronous generators. The power response is expressed as the increased output in the form of a percentage of the rated power of all online units.

	Nuclear	Other thermal	Hydro	Synchronous condensers
H [s]	6	4	3	6
ΔP [%]	48	32	24	48

2.2. Operating reserve

When there is an imbalance between the electricity load and level of generation, some generation (or load) must be added or removed in order to restore equilibrium and prevent the frequency from deviating even further. Traditionally, this reserve generation has been categorized as primary, secondary and tertiary reserves, referring to the order in which they are activated following an imbalance. However, this categorization is based on traditional, fuel-based systems and is not necessarily suitable for future systems with high shares of VRE, for which different technical limitations to providing reserve capacity apply. Furthermore, the historic reserve levels may also be unsuitable as the share of VRE, electrified industries and number of prosumers increase. For example, in a high-VRE electricity system, different types of storages, gas turbines or VRE would be able to provide down-regulation, whereas VRE typically cannot provide up-regulation without constantly curtailing some energy. Therefore, it is assumed that downregulation is significantly easier to handle than upregulation in high-VRE systems, so only upregulation is studied.

In this study, OR has been implemented as a requirement for spare capacity within each hour. The hour has been split into 7 intervals, corresponding to 10 s–1 min, 1–10 min, 10–20 min and so on, where the first 10 s instead are covered by the inertia power response[1] and the FFR described in the previous section. All intervals are implemented with a uniform need for reserves, which can be met by any dispatchable units, such as hydro power, thermal generation, storages, and curtailed VRE. The amount of OR that each thermal unit can contribute depends on whether the unit is online or offline and on the specific interval being considered. The fractions of rated capacity that can be added are given in Table 2. For example, a combined-cycle gas turbine running at part-load can increase its output to its rated power for intervals 3 to 7, whereas it

[1] In practice, the duration of inertial support or FFR may vary. However, the assumption of 10 s is reasonable from a modeling point-of-view because of the vast capacity for fast frequency control in the investigated scenarios. Further treatment of this topic can be found in the *Discussion* section.

is limited to an increase corresponding to 60% of its rated power for the second interval (*O2dur*). Offline combined-cycle gas turbines can at most reach 67% of their rated power within the hour. The ramp rates and start-up times are based on information from Refs. [22,23]; and can be found in Table A2 in Appendix A. Furthermore, it is assumed that nuclear power in Year 2050 will be state-of-the-art in terms of ramping ability due to the system context in which it will be.

The levels of required reserves are calculated as the sum of three sources: the dimensioning fault (N-1), and load variations and variations from VRE on an intra-hourly scale. The first two parameters are exogenously given to the model,[2] although the variations derived from VRE will increase as VRE investments increase. The N-1 size is assumed to be constant throughout the year, while the reserve demand from load variations vary each day and the demand from VRE variations varies each hour. The reserve demand associated with VRE variations is taken as the difference in the production profile for each consecutive hour. In other words, it is assumed that intra-hourly forecast errors and variations are limited by the inter-hourly variations on a larger regional scale. For balancing the stochastic demand variations, the required reserve has been estimated using a heuristic formula and parameters from the UCTE Operation Handbook:

$$R_i = \sqrt{a^*L_{i,\ max} + b^2} - b$$

where Ri represents the (secondary) reserves required for day i with daily max load $Li{,}max$, and the parameters a and b are 10 MW and 150 MW, respectively. These parameters are given in the handbook as empirically established values for the recommended minimum levels of secondary reserves.

2.3. Electricity system model

The model used in this study is a linear investment and dispatch electricity system model with time-resolution of 1 h and a time-span of 1 year. The model minimizes the total cost (annualized investment and operational costs) to meet the demand for electricity in one region, under the assumption that transmission within the region is without congestion (i.e., no inter-regional or intra-regional transmission is modeled). Unit commitment has been linearly approximated as was done previously [24,25]. A mathematical formulation of the model can be found in Ref. [9]; with additions regarding the VMS described in Ref. [26]. The present work adds several equations, variables and parameters designed to capture the demand and supply of OR and inertia. This section includes a basic mathematical description of the model, followed by the additions made in this work. All the sets, variables and parameters used in the description of the modeling can be found in Table 3.

The main sets in the model are region (R), time (T) and technology (P), and the main decision variables are production and storage technology investments (i) and power generation (g). Additional variables include total system cost ($ctot$) and hourly storage level (l), charging (c), and discharging (d). Furthermore, the model includes a linearized and continuous variable approximation to represent thermal cycling with variables for online capacity (*gactive*) and capacity being started up (*gstart*), as described by Refs. [24,25]. This means that generators can be run at part-load and can be subject to start-up costs and time. Equation (2) expresses the total system cost that is being minimized in the model.

$$\min \sum_{r\in R}\left(\sum_{p\in P} i_{r,p}{*}C_p^{inv} + \sum_{t,p\in T,P\backslash P^{ESS}} g_{r,t,p}{*}C_p^{OPEX} + \sum_{t,p\,\in\,T,P}\left(g_{r,t,p}^{active} - g_{r,t,p}\right){*}C_p^{partload} + \sum_{t,p\,\in\,T,P} g_{r,t,p}^{start}{*}C_p^{start}\right) \tag{2}$$

As shown in Eq. (3), the net electricity generation, considering storage charging and discharging, has to meet an exogenous demand, Dr, at each time-step. However, the generation is limited, for each technology, by the online capacity (*gr,ctive*), which in turn is limited by the installed capacity in Eq. (4). The right-hand-side of Eq. (4) also contains the generation profile (Gr), which limits the hourly production for VRE technologies. For all non-thermal technologies, gr, *ctive* has no meaning and does not influence the operation. The operation of storage is limited by the state-of-charge according to Eq. (5) and by the investments in power capacity according to Eq. (6). In Eq. (6), the p and q terms represent energy storage technologies and their respective power capacity investments for charging and discharging.

$$\sum_{p\in\ P^{gen}} g_{r,\ t,p} + \sum_{p\in P^{ESS}}\left(s_{r,t,p}^{discharge} - s_{r,t,p}^{charge}\right) = D_{r,t},\ \ \forall r,t\in R,T \tag{3}$$

$$g_{r,t,p} \le g_{r,t,p}^{active} \le i_{r,p}{*}G_t,\ \ \forall t,p\in T,P \tag{4}$$

$$g_{r,t+1,p} \le g_{r,t,p} + s_{r,t,p}^{charge}{*}\eta_p^{ESS} - \frac{s_{r,t,p}^{discharge}}{\eta_p^{ESS}},\ \ \forall r,t,p\in R,T,P^{ESS} \tag{5}$$

$$-i_{r,q} \le s_{r,t,p}^{discharge} - s_{r,t,p}^{charge} \le i_{r,q} \le i_{r,p} * S_p^{rate},\ \ \forall r,t,(p,q)\in R,T,Q \tag{6}$$

These equations make up the core of the model expanded upon in this work. A complete description, including all the relevant equations, can be found in Refs. [9,26]. The remainder of this section will detail the additions made to the original model.

In similarity to production meeting the power demand, the inertia power response, *asr,nertia*, and OR, *asr,t,pOR*, must also attain the minimum level required to ensure sufficient frequency control, as described by Eqs. (7) and (8). In the equations listed below, *Ir, ad* refers to the intra-load variations described in the Operating Reserves section, and *IrN*−1 refers to the N-1 values in Table 6.

$$\sum_{p\in P} as_{r,t,p}^{inertia} \ge I_r^{N-1},\ \ \forall r,t\in R,T \tag{7}$$

[2] For example, N-1 and load variations result in 520–730 MW of reserve demand in the *Wind* case with an average load of 3.3 GW, and 1552–1678 MW of reserve demand in the *Hydro + wind* case with an average load of 10.5 GW.

Table 2
Fractions of rated capacity that can be ramped up for each intra-hourly reserve interval, O_o^{dur} [as used in Eq. (12)].

	O_1^{dur} 10–60 s	O_2^{dur} 1–10 min	O_3^{dur} 10–20 min	O_4^{dur} 20–30 min	O_5^{dur} 30–40 min	O_6^{dur} 40–50 min	O_7^{dur} 50–60 min
Energy storages							
Li-ion battery	1	1	1	1	1	1	1
Hydrogen	1	1	1	1	1	1	1
Flywheels	1	1	1	1	1	1	1
Hydro power	1	1	1	1	1	1	1
Online thermal plants							
CC GT	0.06	0.6	1	1	1	1	1
OC GT	0.125	1	1	1	1	1	1
ST	0.045	0.45	0.9	1	1	1	1
Nuclear	0.045	0.45	0.9	1	1	1	1
GT CCS	0.08	0.8	1	1	1	1	1
ST CCS	0.06	0.6	1	1	1	1	1
Offline thermal plants							
CC GT	0	0.21	0.67	0.67	0.67	0.67	0.67
OC GT	0	0.31	1	1	1	1	1
ST	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0
GT CCS	0	0	0	0	0	0	0
ST CCS	0	0	0	0	0	0	0

CC: Combined-cycle, OC: open cycle, GT: gas turbine, ST: steam turbine, CCS: carbon capture and storage.

Table 3
Sets, variables and parameters used in the equations describing the modeling.

Sets		
R	Regions, {1,..,4}	
T	Time-step, {1,..,8784}	
P	Technology	
P^{VRE}	Variable renewable technologies (wind and solar)	
$P^{inertia}$	Technologies able to provide inertia	
P^{OR}	Technologies able to provide operating reserves	
P^{ESS}	Energy storage technologies	
P^{gen}	Electricity generating technologies	
O	Operating reserve interval {1,..,6}	
Variables		
$i_{r,p}$	Investment in technology p in region r	[GW]
$g_{r,t,p}$	Generation from technology p at time-step t in region r	[GWh/h]
$s^{charge}_{r,t,p}$	Charging of storage p in region r at time-step t	[GWh/h]
$s^{discharge}_{r,t,p}$	Discharging of storage p in region r at time-step t	[GWh/h]
$as^{inertia}_{r,t,p}$	Available inertial power	[GW]
$as^{OR}_{r,t,p,o}$	Available operating reserves	[GW]
Parameters		
η^{ESS}_p	Charging and discharging efficiency of technology p	[–]
$D_{r,t}$	Electricity demand during hour t in region r	[GWh]
$G_{t,p}$	Hourly profile for VRE (constant 1 for dispatchable technologies)	[–]
C^{inv}_p	Investment cost for technology p	[k€/GW]
C^{OPEX}_p	Running cost (fuel and variable O&M) for technology p	[k€/GWh]
C^{start}_p	Start-up cost for technology p	[k€/GW]
C^{part}_p	Part-load cost	[k€/GW]
$I^{load}_{r,t}$	Power reserve demand due to intra-hourly load variations	[GW]
I^{N-1}_r	Power reserve demand to cover for worst single fault (N-1)	[GW]
I^{dur}	Duration of inertia power response (10 s)	[s]
I^{sync}_p	Inertial power response from synchronous generators (see Table 1)	[–]
$O^{on}_{p,o}$	Ability of technology p to increase output until reserve interval o	[–]
$O^{off}_{p,o}$	Ability of technology p to start up until reserve interval o	[–]
O^{dur}_o	Duration of reserve window o	[s]
Q	$P \times P$ matrix connecting energy storages with their respective power capacity technology (e.g., fuel cells, inverters)	[–]
S^{rate}_p	Storage (dis)charge rate as a fraction of storage per hour	[–]

$$\sum_{p\in P} as^{OR}_{r,o,t,p} \geq I^{load}_{r,t} + I^{N-1}_r + \sum_{p\in P^{VRE}} i_{r,p} * max\Big(\times \left|G_{r,t,p} - G_{r,t-1,p}\right|, \left|G_{r,t+1,p} - G_{r,t,p}\right|\Big), \ \forall r,o,t \in R,O,T \tag{8}$$

In Eq. (8), *ir,*maxGr,t,p−Gr,t−1,p, Gr,t+1,p−Gr,t,p* represents the hour-to-hour variations of VRE, i.e., the extent to which the production may be ramped up/down during the time-step. The variable for spinning capacity, *gr,ctive*, is further constrained to approximate the start-up cost, start-up time, minimum load and part-load operation using continuous variables [the complete thermal cycling approximation can be found in Ref. [9]]. Additionally, *gr,t, pactive* also determines how much inertia power response, *asr,t,pinertia*, and OR, *asr,t,pOR*, is available for synchronous technologies according to Eqs. (9) and (10).

$$as^{inertia}_{r,t,p} \leq g^{active}_{r,t,p} * I^{sync}_p, \ \forall r,t,p \in R,T,P^{inertia} \tag{9}$$

$$as^{OR}_{r,t,p,o} \leq \left(g^{active}_{r,t,p} - g_{r,t,p}\right) * O^{on}_{r,p,o} + \left(i_{r,p} - g^{active}_{r,t,p}\right) * O^{off}_{r,p,o}, \ \forall r,t,p,o \in R,T,P^{OR} \tag{10}$$

The batteries and flywheels are also able to provide synthetic inertia (depending on the scenario) and reserves. The two factors that limit the ability of storage systems to provide inertia and

Table 4
The scenarios (excluding sensitivity analyses) and cases used as input to the modeling. Modeled cases are based on real regions in terms of load profiles and access to renewable resources.

Scenario	Description
Base	Core model without inertia or OR constraints
OR	Hourly ORs need to meet the sum of demands
Inertia	Hourly inertia must meet the static value
Inertia (noSyn)	Same as *Inertia* but without nonsynchronous sources
OR + Inertia	Combined OR and inertia constraints
Regional case	
Hydro + wind	Based on southern Sweden
Wind	Based on Ireland
Solar	Based on central Spain
Inland	Based on Hungary

Table 5
Storage and inertia technologies included in the modeling, as well as their investment costs and operational limitation. Note that additional operation and maintenance (O&M) costs apply, and reservoir hydropower cannot be expanded beyond the capacity in Year 2020. The costs for batteries, hydrogen storage, and flywheels are based on [27] while the synchronous condenser costs are based on [28]. Reservoir hydro power is shown without values, as investment decisions cannot be made for this.

		Costs	Limitation
Li-ion battery	Energy	79 €/kWh	100% (dis)charge per hour
	Power	68 €/kW	
Hydrogen storage	*Energy (Cavern storage)*	11 €/kWh	5% discharge per hour, 2.5% charge per hour
	Charge (Electrolyzer)	395 €/kW	
	Discharge (Fuel cell)	841 €/kW	
Flywheels	Energy and power (E/P = 1/6) (OR and inertia only)	155 €/kW	100% (dis)charge per 10 min
Synchronous condensers	Power (inertial power only)	30 €/kW	Only for synchronous inertia
Reservoir hydro	-	–	–

Table 6
Dimensioning fault (N-1) values for the regional cases included in this work.

	Solar	Inland	Wind	Hydro + wind
N-1 [MW]	1239	605	440	1388

reserves are: (i) power capacity, which is determined by the investment in the storage's corresponding power technology (i.e., inverter and grid connection); and (ii) storage level. Power capacity (i) is considered in Eqs. (11) and (12). The limitation from storage level (ii) is implemented according to Eq. (13) for inertia, and according to Eq. (14) for reserves:

$$as^{inertia}_{r,t,p} - s^{charge}_{r,t,p} + s^{discharge}_{r,t,p} \le i_{r,q} \le i_{r,p} * R^{discharge}_{p}, \ \forall r, t, (p,q) \in R, T, Q \tag{11}$$

$$as^{OR}_{r,t,p,o} - s^{charge}_{r,t,p} + s^{discharge}_{r,t,p} \le i_{r,q} \le i_{r,p} * R^{discharge}_{p}, \ \forall r, t, (p,q) \in R, T, Q \tag{12}$$

$$as^{inertia}_{r,t,p} \le \left(g_{r,t,p} + s^{charge}_{r,t,p} - s^{discharge}_{r,t,p}\right) * \frac{3600}{I^{dur}}, \ \forall r, t, p \in R, T, P^{ESS} \tag{13}$$

$$\sum_{o \in O} as^{OR}_{r,t,p,o} * \frac{O^{dur}_{o}}{3600} \le g_{r,t,p} * \eta^{ESS}_{t} + s^{charge}_{r,t,p} - s^{discharge}_{r,t,p}, \ \forall r, t, p \in R, T, P^{ESS} \tag{14}$$

I^{dur} and O^{dur}_{o} are the lengths of each commitment and add up to 3600 s (1 h), such that when inertia and all reserve intervals o are satisfied, the whole hourly time-step has sufficient power and energy for frequency control.

It should be noted that while this implementation of inertia and reserves affects investments and operation such that the system has extra power to use for frequency management, it does not activate the extra power. The implications of this and the perfect foresight of linear optimization models are considered in the *Discussion* section.

2.4. Cases

The modeling is applied to four cases, corresponding to four regions with distinctly different modes of access to renewable resources and different load profiles: 1) *Hydro + wind*, which is based on southern Sweden with high levels of hydropower and wind power availability; 2) *Wind*, which is based on Ireland with very high availability of wind power; 3) *Solar*, which is based on central Spain with high solar availability; and 4) *Inland*, which is based on Hungary with low VRE resources. As indicated above, these regions are modeled in isolation without the inclusion of any inter-regional transmission. In the context of studying operational reserve and inertia, this limitation resembles conditions of extreme self-sufficiency, since interconnected countries typically share both reserves and inertia. Using this approach, therefore, gives the upper limit of the impact of the studied services by not allowing regions to provide services for each other when possible. However, as long as part of the reserves and inertia is required to remain local (e.g., for stability or energy security reasons), the technologies and strategies used to provide the services will largely be the same.

For each regional case, five scenarios (listed in Table 4) are investigated, to distinguish the impacts of OR, inertia and synthetic inertia. All five scenarios feature a carbon-neutral Greenfield system for Year 2050 with only the present levels of hydropower as pre-existing generation capacity. Additional scenarios are implemented, as described in the *Sensitivity Analysis* section.

The *Base* scenario contains no new constraints and is used as the point of reference for the other scenarios. Scenario *OR* includes constraints on available reserves but not on inertia, and the opposite is the case for the *Inertia* scenario. Instead, the combination of OR and inertia constraints is implemented in the *OR + Inertia* scenario. Lastly, the *Inertia (noSyn)* scenario is used to test the importance of synthetic inertia by not allowing for nonsynchronous sources. Further details of the OR and inertia constraints can be found in the following subsections.

Since this study focuses on inertia, ORs and VMS in carbon-neutral energy systems, several VMS are available in the model and are listed in Table 2. In addition, a range of thermal power technologies is available. A full list of the technologies available in the model, including nuclear power, biomass, biogas, and fossil- and biogas-mixed carbon capture and storage (CCS) can be found in Table A1, Appendix A.

The N-1 values used to dimension the inertia and OR requirements were calculated in two steps and are listed in Table 6. Initial values for reasonable largest power plant block sizes were chosen by looking at the technology mix and sizes in the *Base* case for each region. It was found that the ratio of the largest plausible power block size to the yearly electricity demand was similar for all regions (in the range of 15–20 MW*yr/TWh) with the exception of the *Hydro + wind* case, for which the ratio was about one-third (6.5). Since the purpose of this study was to investigate the impact of inertia constraints in systems with different technology mixes, rather than systems of different sizes, the N-1 value was adjusted to give the same ratio (15 MW*yr/TWh) for each region investigated. For *Hydro + wind*, this adjusted N-1 value is similar to the currently N-1 dimensioning nuclear reactor in Sweden.

3. Results

Figs. 1 and 2 show the installed electricity generation, storage and synchronous condenser capacities for the five scenarios investigated for the *Inland* and *Wind* cases, respectively (corresponding results for the *Solar* and *Hydro + wind* cases are presented in Appendix B). From the figures, it is evident that the installed capacity is very similar for all the scenarios, indicating that the requirements related to capacity available for inertia and ORs have weak impacts on the cost-optimal technology mix for electricity generation and storage. The most notable effect in terms of installed capacity is seen for the scenarios with reserve requirements, for which more investments are made in battery storage and power.

A slight decrease in solar PV capacity is also found in the *Wind* region, due to the increased OR demand from ramping solar PV. The effect of requiring capacity available for the inertia power response is even weaker than the impact of requiring capacity for ORs. This because a higher capacity is required for OR and the already installed battery and wind power capacities can provide sufficient levels of synthetic inertia at no, or low, additional cost in terms of dispatch. When synthetic inertia is not allowed, synchronous condensers are preferred over thermal options for inertia provision, since it would be very costly for thermal plants to remain online for a few hours solely to provide inertia.

Table 7 lists the indicators for all scenarios and regional cases listed in the *Methodology* section. It is evident that the synchronous condenser and battery are the main providers of synchronous inertia and reserve, respectively. The small change in cost shows that inertia constraints alone have little impact on the system when synthetic inertia is allowed. The VRE share is separated into solar share and wind share, to show how the OR requirement causes a slight shift from solar to wind. The reason for this is that the reserve requirement is formulated so as to depend on hour-to-hour variations in VRE production. Thus, the required level of reserve can be decreased by shifting investments away from solar PV, which is particularly variable.

In general, an increase in battery storage capacity is the main change in investments in all regions when OR constraints are introduced. While small changes in dispatch can be seen for some hours in the Hydro + wind region, the main source of reserves is from having additional energy in the batteries during hours of otherwise low storage levels. The curtailment is also slightly reduced in the OR scenarios for all regions, since the increased storage capacity allows for more excess electricity to be absorbed (except in the *Hydro + wind* case, which has a large share of dispatchable generation and a lot of flexibility from reservoir hydropower). This advantage of double-use of the additional batteries is evident, in part, when comparing the investment and O&M costs imposed on the model from the battery investments with the difference in system cost. If the increase in system cost is smaller than the cost of the new battery capacity, then there must be additional uses for the additional capacity. On the other hand, if the increase in system cost is larger than the battery cost, then there must be other costs imposed from the OR requirements. The differences between these two costs are shown for the *Base* and OR case for all regions in Table 8.

Table 8 shows that for the *Inland* and *Hydro + wind* cases, there is double-usage of the extra batteries, as the system cost increase is

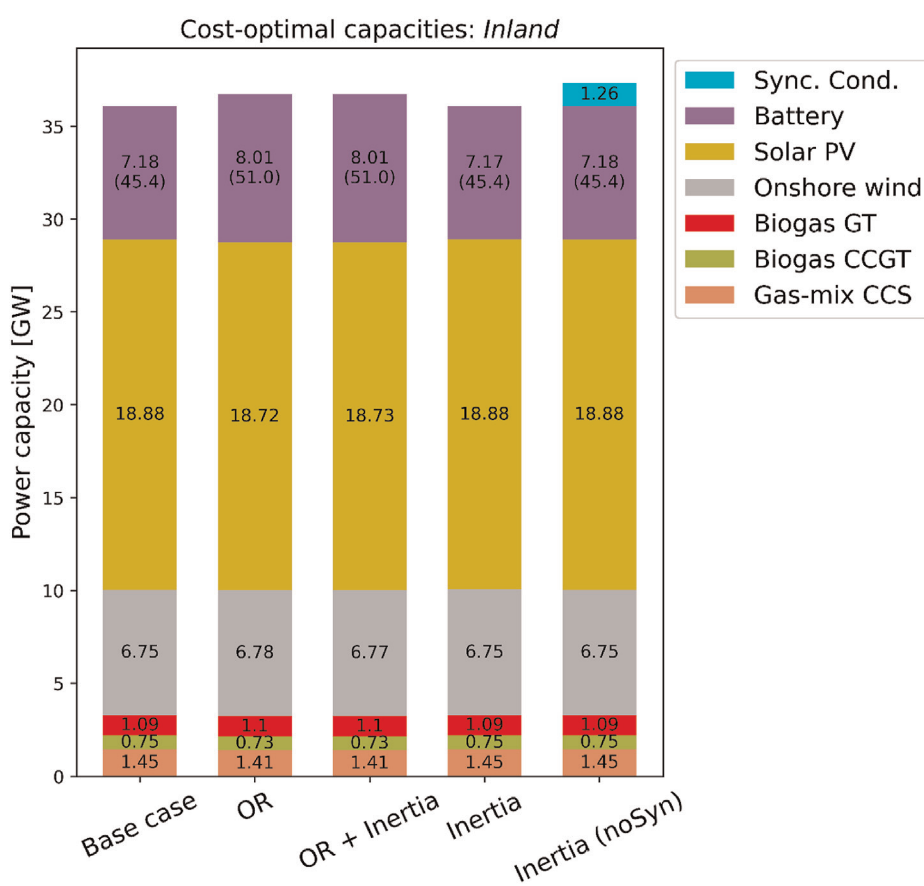

Fig. 1. Cost-optimal installed capacities for all scenarios in the *Inland* region. Numbers in parentheses for batteries are the storage capacities in GWh. Sync. Cond.: synchronous condensers.

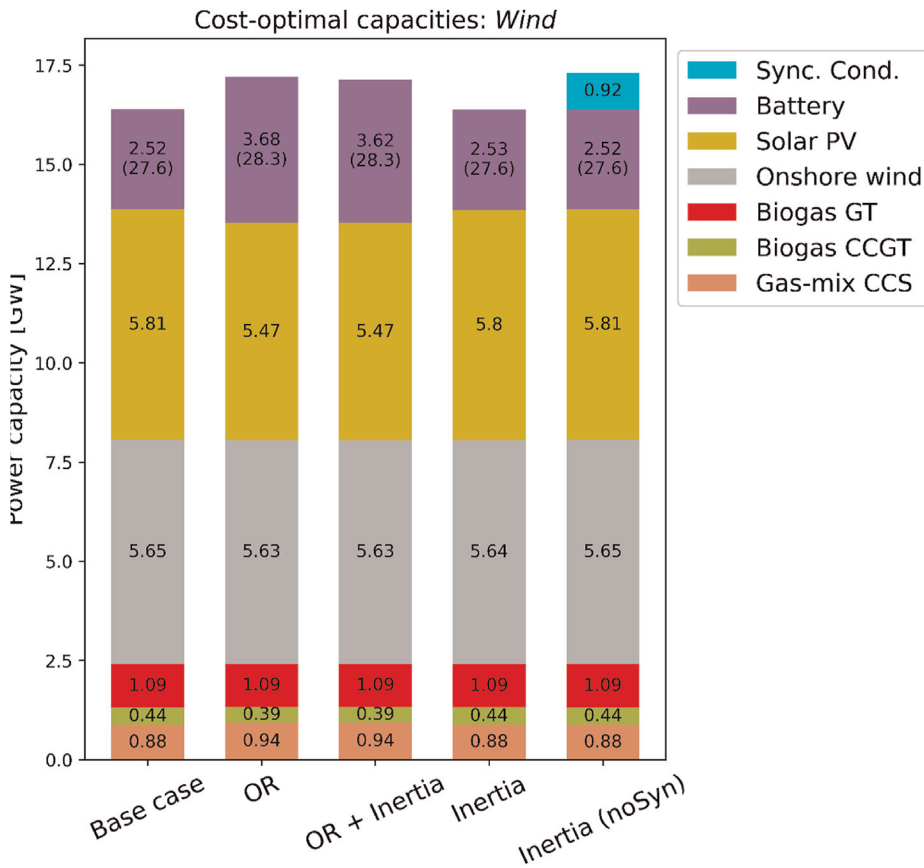

Fig. 2. Cost-optimal installed capacities for all scenarios in the *Wind* region. Numbers in parentheses for batteries are the storage capacities in GWh. Sync. Cond.: synchronous condensers.

Table 7
Summary of the scenarios according to indicators. The main changes that occur between the base case and each scenario are highlighted in bolded text.

		Annual system cost [G€/yr]	Cost change [–]	*Wind* share [–]	*Solar* share [–]	Curtailed energy [–]	Synchronous condenser capacity [GW]	Battery storage/power [GWh/GW]
Solar	*Base*	3.627	–	29.2%	65.1%	16.9%	0	103.68/16.99
	OR	3.685	1.59%	30.5%	63.8%	16.4%	0	**112.06/17.52**
	OR + Inertia	3.685	1.60%	30.7%	63.6%	16.4%	0	**112.06/17.52**
	Inertia	3.629	**0.06%**	29.8%	64.6%	16.8%	0	104.28/16.94
	Inertia (noSyn)	3.632	0.16%	31.6%	62.8%	16.7%	**2.58**	103.73/17.04
Inland	*Base*	2.116	–	36.7%	53.5%	15.8%	0	45.43/7.18
	OR	2.141	1.17%	37.4%	52.9%	15.6%	0	**50.99/8.01**
	OR + Inertia	2.141	1.17%	37.1%	53.3%	15.6%	0	**50.99/8.01**
	Inertia	2.117	**0.05%**	36.7%	53.5%	15.9%	0	45.44/7.17
	Inertia (noSyn)	2.119	0.15%	39.3%	51.0%	15.7%	**1.26**	45.43/7.18
Wind	*Base*	1.254	–	75.7%	16.3%	18.8%	0	27.59/2.52
	OR	1.265	0.84%	76.1%	15.5%	18.2%	0	**28.28/3.68**
	OR + Inertia	1.265	0.85%	76.4%	15.2%	18.1%	0	**28.28/3.62**
	Inertia	1.255	**0.04%**	76.7%	15.3%	18.7%	0	27.58/2.53
	Inertia (noSyn)	1.257	0.19%	75.9%	16.1%	18.9%	**0.92**	27.59/2.52
Hydro +wind	*Base*	2.845	–	60.7%	0.0%	24.3%	0	32.72/3.48
	OR	2.859	0.51%	60.8%	0.0%	24.5%	0	**34.62/5.24**
	OR + Inertia	2.860	0.51%	60.8%	0.0%	24.5%	0	**34.62/5.24**
	Inertia	2.845	**0.01%**	60.7%	0.0%	24.3%	0	32.67/3.48
	Inertia (noSyn)	2.851	0.22%	60.7%	0.0%	24.3%	**2.41**	32.71/3.48

smaller than the costs imposed by the extra battery capacity. However, in the *Solar* and *Wind* cases, the higher system cost indicates that the OR requirement was met in other ways than just using batteries. Since much of the reserve demand in the *Solar* case comes from ramping solar PV output, imposing OR requirements causes a slight shift from solar PV to wind power (about 2% of the

Table 8
Comparisons of the increased system costs and the battery costs for the OR scenarios in each region.

	Solar	Inland	Wind	Hydro + wind
Battery cost [M€/yr]	49.5	35.5	10.1	20.0
System cost increase [M€/yr]	57.8	24.8	10.5	14.3
System cost increase/Battery cost (%)	117	70	104	72

yearly energy supply). This moves the system away from the cost-optimal energy mix and reduces the need for batteries as a VMS, which explains the greater increase in system cost for the *Solar* case in Table 8. While this shift is also observed for the *Wind* and *Inland* cases, the poor wind and solar conditions of the *Inland* region lead to a greater benefit being derived from the extra batteries.

Fig. 3 gives the available inertial power of the *Inland* electricity system for all hours of the year ordered from the hour with the highest available inertial power to the hour with the lowest available inertial power. Comparison of the *Base* and OR scenarios in Fig. 3 reveals that adding OR constraints significantly increases inertia for all hours of the year. This is because the batteries added for OR provision can also provide synthetic inertia. Thus, adding inertia requirements to already existing OR requirements has almost no effect. It can also be seen in Fig. 3 that when synthetic inertia is *not* allowed, almost all the inertia is instead supplied by investments in synchronous condensers.

Fig. 4 shows the levels of generation, battery (only the useable battery portion), and available reserves for 2 days in the *Solar* case and 3 days in the *Wind* case. Comparing the operation and cause of insufficient reserves in the *Wind* and *Solar* cases in Fig. 4 highlights an important difference between wind-dominated and solar-dominated systems. In the *Solar* case, the lack of reserves occurs during hours of empty battery storage as a consequence of discharging during a high net-load event (see Hours 1735 and 1,759, marked in red on the x-axis in Fig. 4). However, in the *Wind* case, there is a lower battery power capacity, as excess wind power is less concentrated in time than excess solar power. This lower power capacity causes reserve deficiencies also *during* high net-load events when the battery discharge hits the capacity cap. This behavior can be seen during Hours 5972 and 6020 for the *Wind* case (marked in red on the x-axis). However, also in the *Wind* case, occasions with insufficient reserves due to empty batteries occur, as shown during Hour 6035.

Similar to the OR shown in Fig. 4, the inertia in Fig. 5 is not increased by a change in dispatch but rather by investments in batteries (as shown in Table 7). At Hour 6368 (indicated in red on the x-axis), the only difference between the *Base* and *Inertia* scenarios is that the increased battery storage capacity in *Inertia* allows the battery to still have about 1 GWh left at the end of the nightly discharge cycle. It should be noted that changes in dispatch can be found, for example in the *Solar* case where thermals at one point replace battery discharge to allow the batteries to provide fast reserves instead. In the *Hydro + wind* region, where both hydro

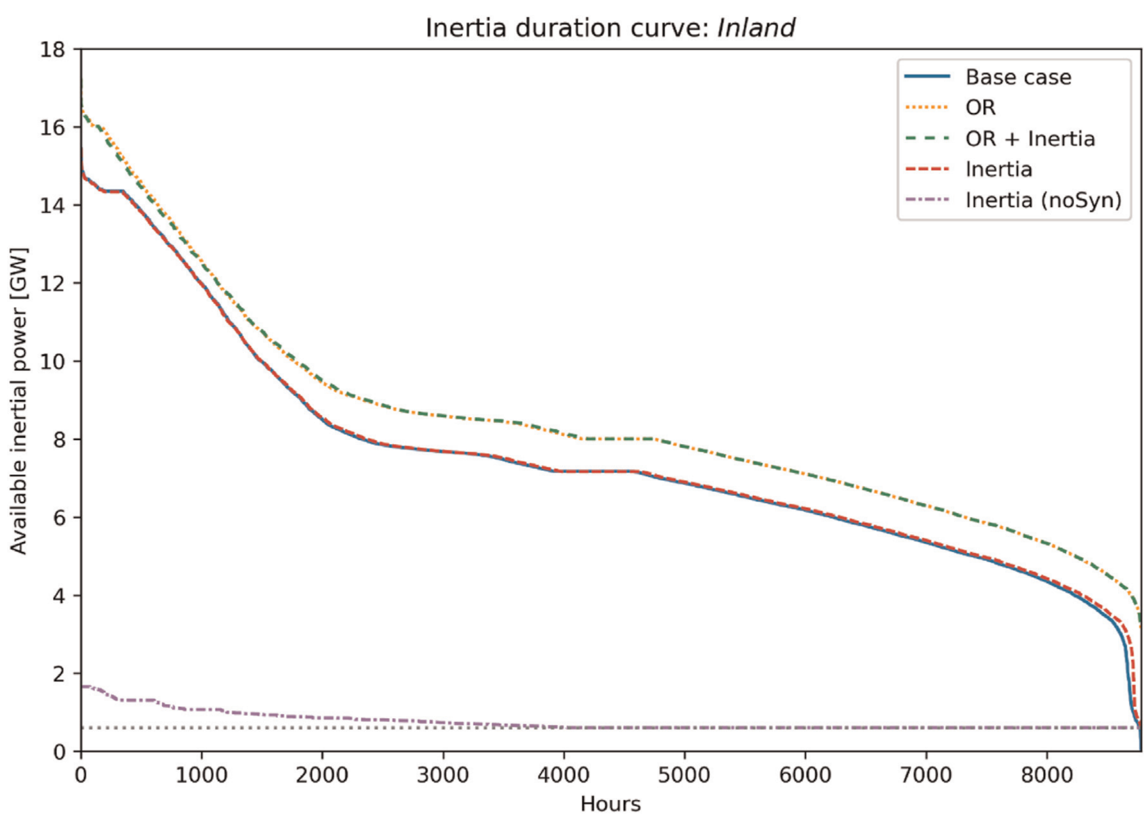

Fig. 3. Duration curves showing the available inertia in the Base, OR, Inertia and Inertia (NoSyn) scenarios for the Inland region. The dotted line indicate the inertia requirements, when applicable (605 MW).

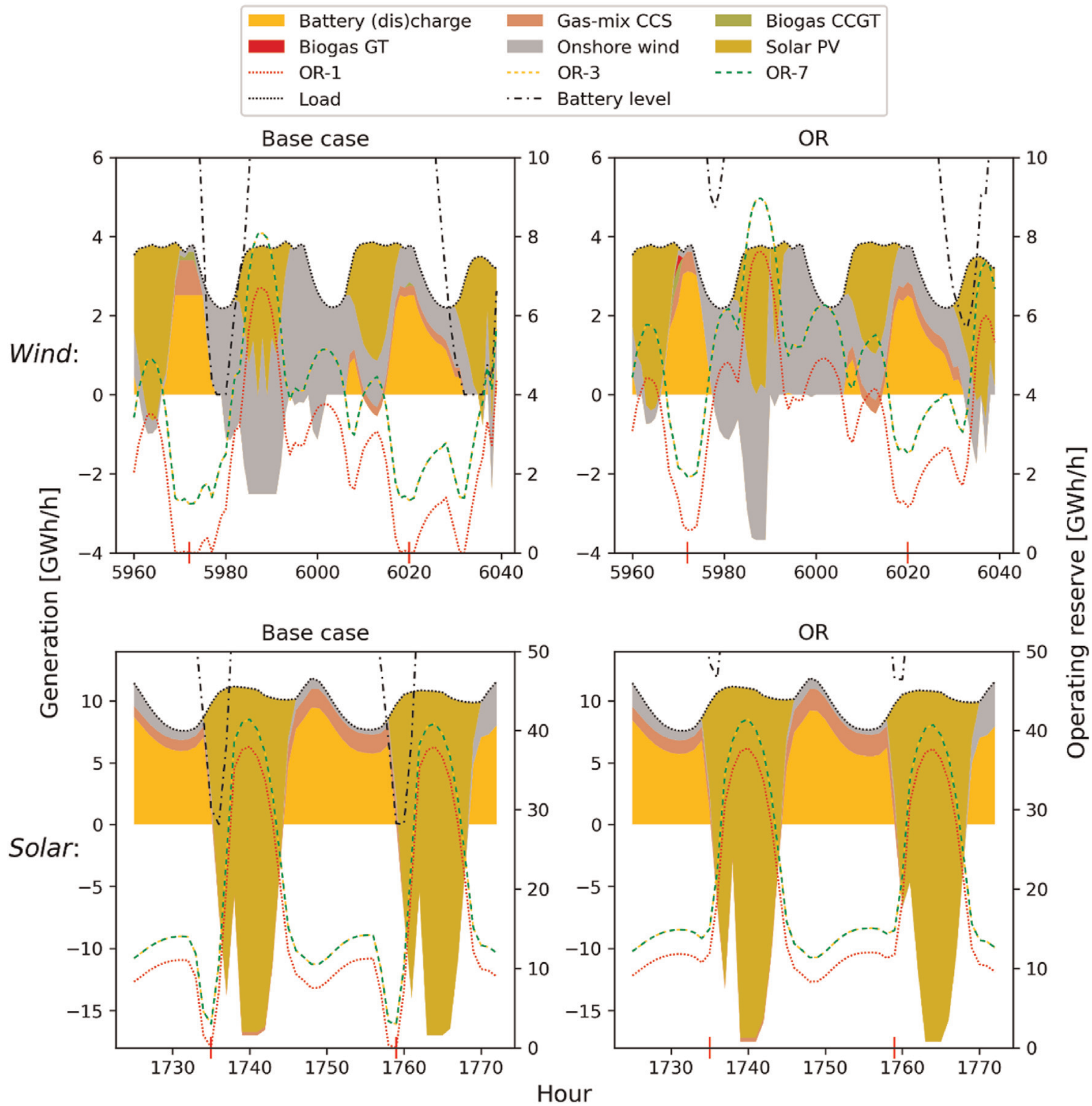

Fig. 4. Generation level, battery level (only useable battery portion) and available reserves for 2 days in the *Solar* case and 3 days in the *Wind* case. Note that a level of generation below zero means that the batteries are being charged, and the state-of-charge continues above the border of the graph but has been cut off in the image.

reservoirs and batteries are present, there are also hours during which the hydropower is discharging instead of batteries to increase inertia. Note that the large differences in timing for battery charging in Fig. 5 [compare, for example, Hour 6420 for *Inertia* and *Inertia (NoSyn)*] are caused by the excess curtailment enabling several same-cost solutions.

3.1. Sensitivity analysis

The results presented here are not sensitive to the synchronous condenser cost, as a halving or tripling of the investment cost has no impact on the investments. In terms of providing synthetic inertia, it is found, by disabling inertia from either batteries or wind power (one at a time), that batteries are especially important in the *Wind*, *Solar*, and *Inland* cases, where their absence leads to extensive replacement by synchronous condensers. In the *Hydro + wind* case, inertia from wind power plays a greater role than batteries, although the absence of either leads to replacement by synchronous condensers.

Increasing battery investment costs affects the results by shifting all the solutions away from batteries and VRE, towards thermal generation of electricity. However, an increased battery cost has little effect on the impacts of adding inertia and OR constraints. When adding OR constraints, a higher battery cost slightly *increases* the additional battery investments, as there is a lower pre-existing battery capacity to use for OR. For inertia, an increase in battery cost yields no change, except for a slight increase in the use of synchronous condensers in the *Solar* case.

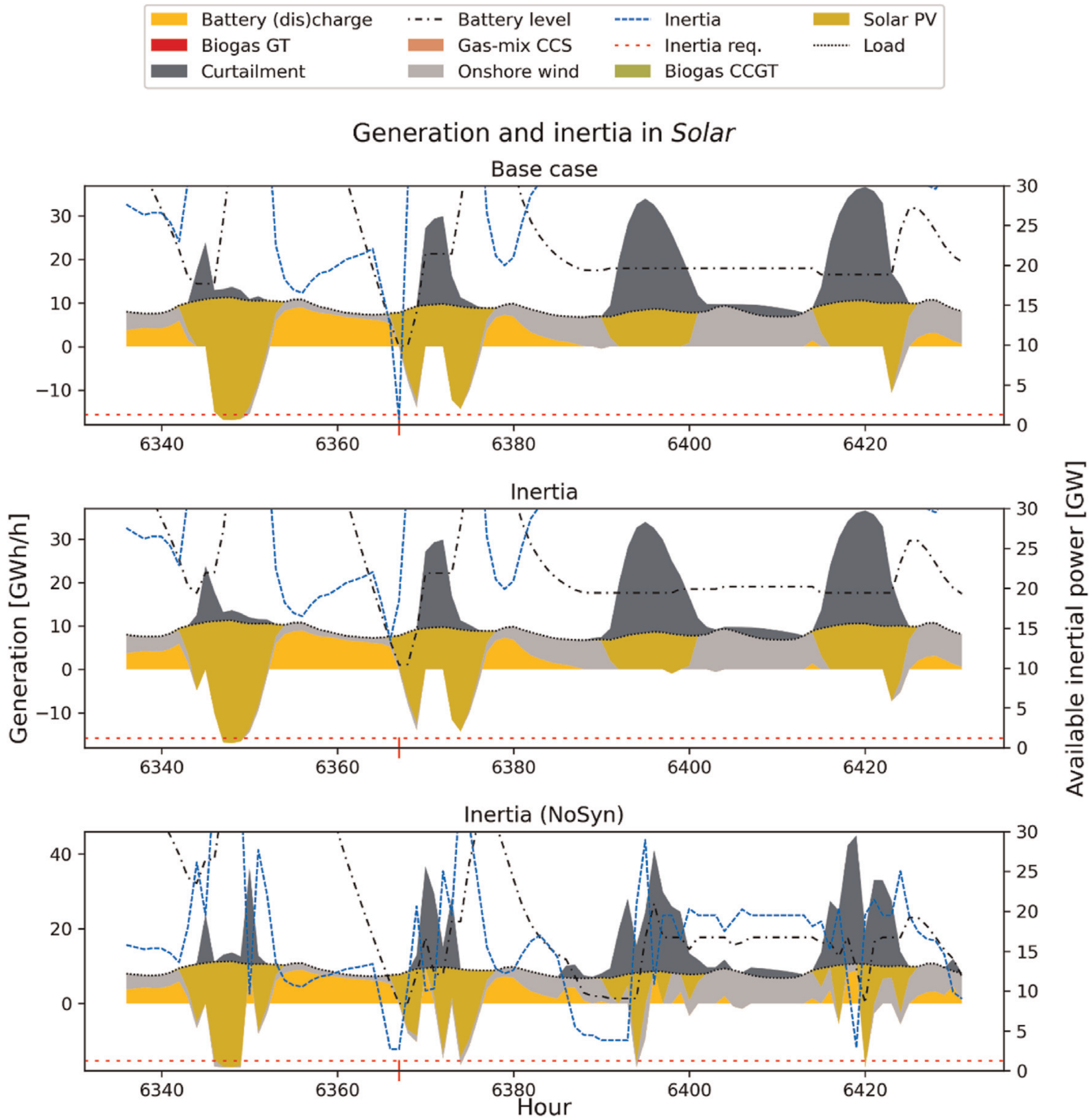

Fig. 5. Generation level, battery level and available inertia for 1 week the *Solar* case. Note that a level of generation below zero means that the batteries are being charged, and some lines continue above the border of the graph but have been cut off in the image.

4. Discussion

Since the model used in the present study has an hourly resolution and the inertia and OR constraints are implemented as a requirement on the *availability* of inertia and reserves, the batteries need to be available but are not actually discharged for the sake of OR/inertia. This might lead to an energy deficit, although the batteries are also not charged during intra-hourly periods of excess generation. It is assumed that the combined effect of not charging and not discharging is close to zero on the scale of several hours, whereas the fastest storage cycles in the results are once per day (in the *Solar* case). Furthermore, the high-VRE containing systems investigated in this study are all characterized by high levels of curtailment and the online presence of thermal plants during longer high net-load periods. These factors could mitigate any potential energy deficits. However, before drawing generalized conclusions about frequency control in future high-VRE systems, the operability and extent of potential energy deficits in the system compositions obtained in this study should be further tested in separate dispatch and frequency simulation studies.

Comparing the *Base*, *Inertia* and *Inertia (NoSyn)* scenarios in Table 7 suggests that providing inertial power, even for high estimates of N-1 values, may be carried out at virtually no additional cost to the system. Furthermore, if a system operator instead wants to maintain a fleet of synchronous inertia, the cost is in the single digits of M€ per year (3, 3, 5 and 6 M€/yr for the *Wind*, *Inland*, *Solar* and *Hydro* + *Wind* cases, respectively). When borne by the consumers, this cost corresponds to approximately 0.1 €/MWh or about 0.15%–0.2% of the average marginal cost of electricity. Clearly, inertia costs will not have a significant impact on the design of a future renewable electricity system.

Unlike inertia, OR requirements significantly affect the battery investments, especially in the *Hydro + wind* and *Wind* regions, where the battery power capacity was increased by 45%–50%. While this suggests that excluding reserve requirements in electricity system models will lead to an underestimation of the value of batteries, the system cost impact is still low (1%–1.5%), and the total VRE share is very similar in the *OR* and *Base* scenarios.

The results of this work point to OR constraints being more influential than inertia when modeling high-VRE electricity systems. While it can be argued that an inertia constraint with a 10-s timeframe is too long, this would only be true if the inertial response was primarily supplied by synchronous machines. The *Inertia* scenarios show that all the studied regions have battery capacities that can be made available for FFR. Thus, complementing the inertial response from synchronous machines with FFR can be done at little to no additional cost to the investigated systems. Still, this raises the questions as to how and when to transition from thermal plant-based OR, which cannot be answered with the Greenfield model used in this study. Thus, it will be important to investigate this in future studies of the timing and dynamics of this transition on a broader energy-system scale. It is also important to note that specific grid codes or markets may be necessary to ensure that battery owners contribute with their potential inertial power and reserve capacity.

5. Conclusion

Using a combined investment and dispatch model with hourly time-resolution, we show that the requirements for inertial power and ORs have weak impacts on the optimization objective (0.5%–1.6% change in total system cost), as well as the resulting composition and dispatch. Furthermore, to satisfy the inertia and OR constraints in energy system optimization models, investments are shown to play a significantly greater role than changes in dispatch. While this suggests that dispatch-only models are insufficient to capture reserve services on their own, this is only true in the cost-optimal sense and in scenarios with high levels of VRE, curtailment and batteries. However, the investments are largely confined to batteries and are specifically focused on battery power capacity in wind-dominated systems and battery storage capacity in solar PV-dominated systems. Furthermore, the capacity to provide inertia during all hours of the year is found to already exist (mostly in the form of synthetic inertia) from energy-purpose optimization. If synchronous inertia is mandated, all the investigated regional cases will invest in synchronous condensers with virtually no other change to the system. This suggests that requirements for inertia in electricity system modeling are unnecessary, unless explicitly studied.

To conclude, batteries combined with wind power are cost-efficient ways to provide reserves and inertia in future, high-VRE energy systems.

CRediT authorship contribution statement

Jonathan Ullmark: Conceptualization, Methodology, Formal analysis, Data curation, Writing – original draft, Visualization. **Lisa Göransson:** Conceptualization, Methodology, Writing – review & editing, Supervision. **Peiyuan Chen:** Conceptualization, Writing – review & editing. **Massimo Bongiorno:** Conceptualization, Writing – review & editing. **Filip Johnsson:** Conceptualization, Writing – review & editing, Supervision, Funding acquisition.

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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Appendix A

Table A1 lists the economic and technical data used in the model. The wind and solar PV, as well as the hydrogen and battery storage system data are based on [29]; while the thermal and nuclear plant data are based on [30].

Table A1
Techno-economic data for the electricity generation plants included in this study.

	Investment cost [€/kW]	Fixed O&M [k€/kW]	Variable O&M [k€/kWh]	Lifespan [yr]	Efficiency [%]	Min. load [%]	Start-up cost [k€/GW]
Nuclear	4124	154	0	60	33	70	400
Biomass ST	2049	54	2.1	40	36	30	57
Gas-mix CCS	1626	40	2.1	30	55	30	57
Biogas CCGT	932	13	0.8	30	62	30	43
Biogas GT	466	8	0.7	30	42	30	20
Offshore wind	1788	36	1.1	30	–	0	0
Onshore wind	968	13	1.1	30	–	0	0
Solar PV	418	7	1.1	40	–	0	0

O&M: Operations and maintenance, CCGT: combined-cycle gas turbine, GT: gas turbine, ST: steam turbine, CCS: carbon capture and storage.
The ramping and start-up characteristics of the thermal plants, used to construct Table 2 in the *Operating Reserve* section, are listed in Table A2 below.

Table A2
Technical data from Refs. [22,23] used to construct Table 5. The biomass-fired steam turbine (ST) is assumed to share flexibility characteristics with the lignite-fired and hard coal-fired power plants.

	Start-up time [min]	Ramping rate [%/min]	Min. load [%]
Nuclear	1440	4.5	70
Biomass ST	360	4.5	30
Gas-mix CCS	180	8	30
Biogas CCGT	180[a]	6	30
Biogas GT	7.5	12.5	30

CCGT: combined-cycle gas turbine, GT: gas turbine, ST: steam turbine, CCS: carbon capture and storage.
[a] It is assumed that the gas turbine can, if so required, start up without the combined cycle to provide reserves.

Appendix B

Figures B1 and B2 show the installed capacities for Hydro + wind and Solar, similar to Figs. 1 and 2 in the Results section.

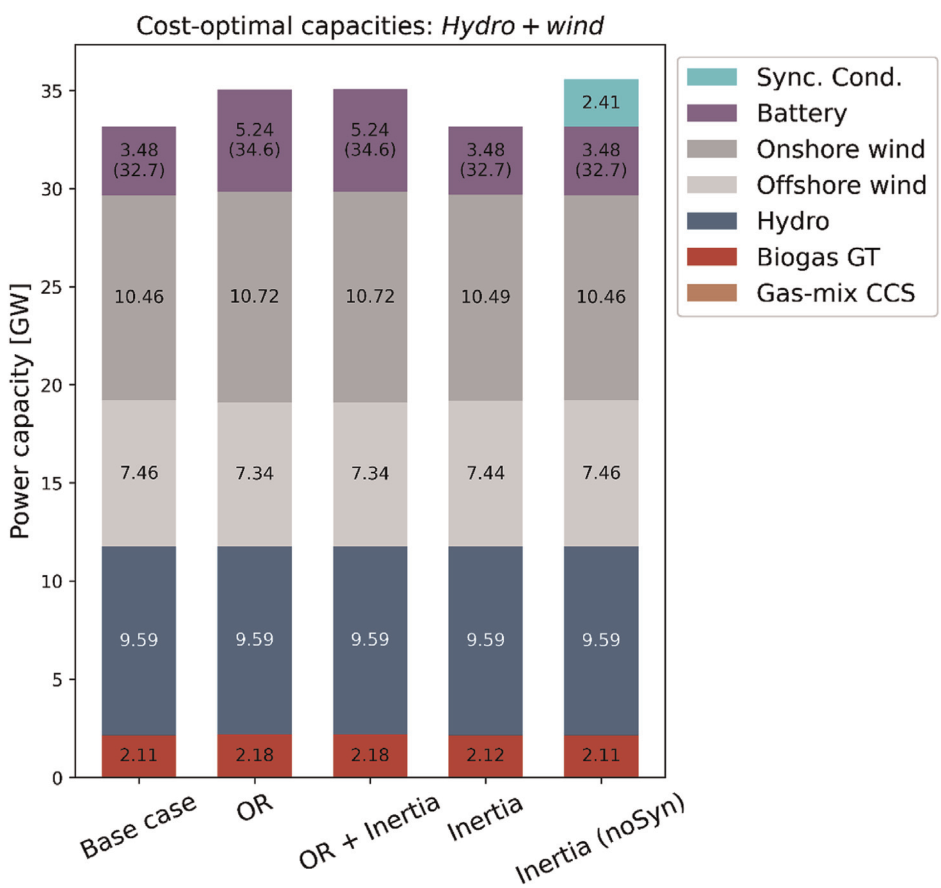

Fig. B1. Cost-optimal installed capacities for all scenarios in the *Hydro + wind* case. The numbers in parentheses for batteries represent the storage capacities in GWh. Sync. Cond.: synchronous condensers.

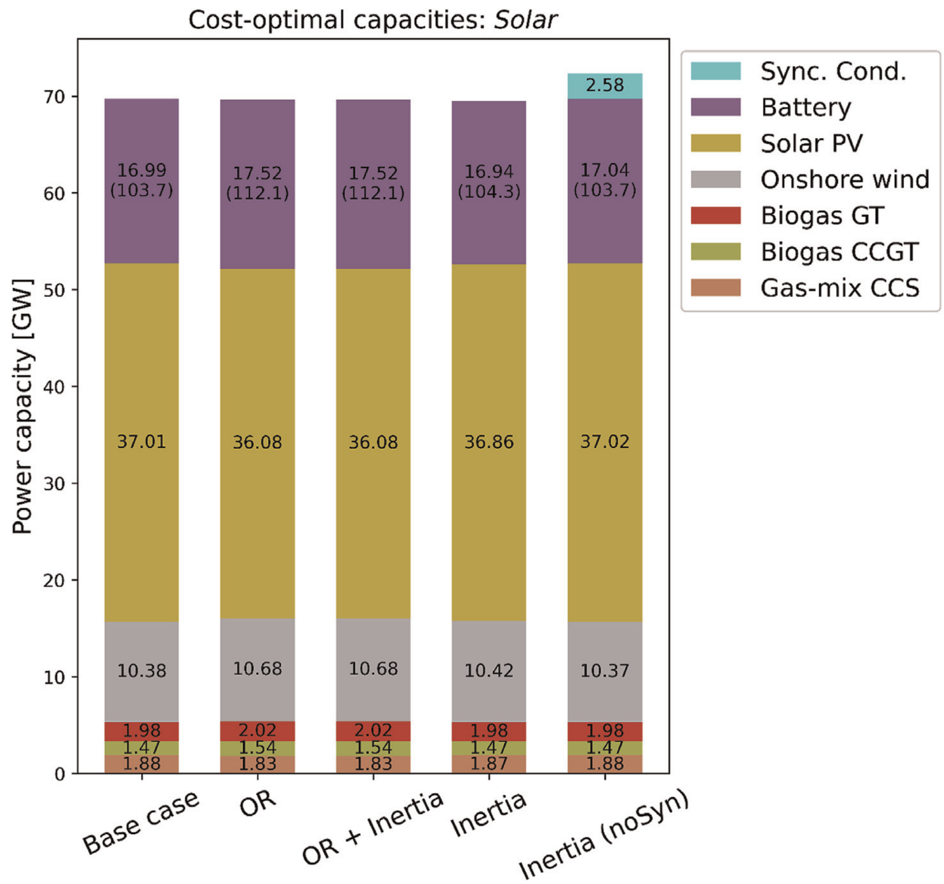

Fig. B2. Cost-optimal installed capacities for all scenarios in the *Solar* case. The numbers in parentheses for batteries represent the storage capacities in GWh. Sync. Cond.: synchronous condensers.

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