Frequency control and synthetic inertia in energy systems modeling

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HIGHLIGHTS:

- Operating reserve and inertia constraints have been tested in wind and solar dominated systems
- Inertia and operating reserve constraints impact investments more than dispatch
- Batteries are the main source of reserves while wind power and batteries both give synthetic inertia
- Without synthetic inertia, investments in synchronous condensers cover the inertia demand
- The overall impact is largely predictable and has a very limited effect on energy generation

1 ABSTRACT

This study investigates how inclusion of frequency control constraints in electricity system modeling impacts the investment and dispatch in electricity generation and storage technologies for futures with high penetration of variable renewable energy. This is done using a linear cost-minimizing investment and dispatch model using historical load, wind and solar power conditions from Spain, Ireland, Sweden and Hungary for the year 2050. With an hourly time-resolution, constraints are added to ensure that, within each hour, sufficient inertial power and reserves are available to control the frequency. Comparing the results with and without these constraints show that nearly all impact on the results is in battery investments and operation. Furthermore, it is found that reserve requirements have a higher impact on system composition and operation than inertial power requirements.

2 INTRODUCTION

Variable renewable energy (VRE) sources such as wind and solar power are projected to provide a substantial part of our electricity if we are to meet climate targets. Due to the non-dispatchable nature of these energy sources, their increased deployment will also increase the need for variation management strategies (VMSs) for efficient integration of VRE, maintaining its value with increasing share. Examples of VMS are strategic use of batteries and hydrogen storage, power to heat by using controlled heat pumps and flexible thermal CHP plants (Göransson and Johnsson, 2018). However, the transition to VRE-dominated power systems also adversely affects the conventional way of controlling the frequency of the power grid. Conventional grid frequency 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 do not provide synchronous inertia. Hence, the transition to VRE raises the risk of insufficient synchronous inertia needed to secure frequency stability. In addition to reduced synchronous inertia, operating reserves (OR) can also be adversely affected when dispatchable power plants are replaced by VRE (Helistö, Kiviluoma, Holttinen, *et al.*, 2019).

Since both inertia and OR are vital to power system operation and will be adversely affected by a transition to VRE unless addressed, various power engineering tools simulating physical principles and relationships have been used to study how frequency deviations might be managed in future systems (Lidstrom and Wall, 2016; Teng and Strbac, 2016; Thiesen, Jauch and Gloe, 2016; Yu *et al.*, 2016; Ahmadyar *et al.*, 2018; Hadjikypris, Efthymiou and Georghiou, 2019 and more). However, the tools used to simulate frequency responses cannot, due to limitations in model complexity and purpose, also 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 detail in terms of temporal resolution and span, as well as operational constraints, geographical scale and technology representation (Loulou, Goldstein and Noble, 2004; Odenberger, Unger and Johnsson, 2009; Göransson *et al.*, 2017; Heuberger, Rubin, *et al.*, 2017; Wiese *et al.*, 2018; Helistö, Kiviluoma, Ikäheimo, *et al.*, 2019). Some of these have been used to study the system impact of constraints on reserve capacity (van Stiphout *et al.*, 2017; van Stiphout, De Vos and Deconinck, 2017) and inertia (Johnson *et al.*, 2019). Even more studies have included constraints on inertia or reserves but not explicitly studied them (Heuberger, Staffell, *et al.*, 2017; Heuberger, 2018; Helistö, Kiviluoma, Ikäheimo, *et al.*, 2019). However, there is a lack of studies investigating how inertia and reserves impact the cost-optimal system composition in future carbon-neutral electricity systems with high shares of VRE. In particular, there is a need to investigate to which extent strategies with the purpose of managing variability of wind and solar power can be deployed to provide frequency control and operating reserves. It is thus unclear what the cost will be of providing these services in future carbon-neutral systems, how they will be provided and how their provision will affect the cost-optimal system composition.

This study adds constraints on intra-hourly operational reserve and inertial power capacity to the electricity system model described in (Göransson *et al.*, 2017). The model minimizes total system cost through linear optimization of both investments and operation on an hourly time-scale with a horizon of one year. The combination of a full year and hourly resolution makes the model suitable to study the interaction between generation technologies and variation management strategies (VMSs) including strategies for short-term balancing of generation and load as well as options for multiday and seasonal storage. A list of included VMSs can be found in Table 2, and Table 3 gives a list of generation technologies included in modeling. The model, on a technology level, includes operational constraints such as ramping, part-load and start-up which all have been shown by van Stiphout *et al.* (2017) to be important when analyzing the requirement of 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, results are primarily relevant to understand the interaction between intra-regional electricity generation technologies and variation management strategies and not to suggest electricity system compositions for actual regions or countries.

This study aims to investigate how demands of inertia and operating reserve in various system contexts impacts 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 VMSs and the provision of ancillary services. In addition, the consequences of *not* allowing inverter-interfaced technologies to provide synthetic inertia is investigated.

3 METHODOLOGY

The modeling is applied to four cases, corresponding to four regions with distinctly different access to renewable resources and different load profiles: *Hydro+wind* which is based on southern Sweden with high hydropower and wind-power availability, *Wind* which is based on Ireland with very high wind-power availability, *Solar* from Spain with high solar availability and lastly *Inland* which is based on Hungary with low VRE resources. The cases are based on regional conditions in terms of load profiles and access to renewable resources. As indicated above, these regions are modelled in isolation without 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 reserves and inertia. Using this approach thus gives an 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 1) are investigated to isolate the impact of operating reserve, inertia and synthetic inertia. All five scenarios feature a carbon-neutral greenfield system for Year 2050 with only present levels of hydropower as pre-existing generation capacity. Additional scenarios are also implemented for in the Sensitivity Analysis section.

Table 1. The scenarios (excluding sensitivity analyses) and cases used as input to the modeling. Modelled cases are based on real regions in terms of load profiles and access to renewable resources.

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

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

Since the aim of this study is centered on inertia, operating reserves and VMSs in carbon-neutral energy systems, the available VMSs are listed in Table 2 below. Additionally, is available. A full list of 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.

Table 2. Storage and inertia technologies included in the modeling, as well as their investment costs and operational limitation. Note that additional O&M costs apply, and reservoir hydropower cannot be expanded beyond 2020 capacity. Costs for batteries, hydrogen storage and flywheels are based on (Danish Energy Agency and Energinet, 2018) while synchronous condenser costs are based on (Igbinovia *et al.*, 2016). Reservoir hydro power is shown without values since no investment decisions can be made for it.

		Costs	**Limitation**
Li-ion battery	Energy	79 €/kWh	100% (dis)charge per hour
	Power	68 €/kW	
	Energy (Cavern storage)	11 €/kWh	

Hydrogen storage	*Charge (Electrolyzer)*	395 €/kW	5% discharge per hour, 2.5 % charge per hour
	Discharge (Fuel cell)	841 €/kW	
Flywheels	Energy and power (E/P = 1/6) (OR and inertia only)	155 €/kW	100% (dis)charge per 10 minutes
Synchronous condensers	Power (inertial power only)	30 €/kW	Only for synchronous inertia
Reservoir hydro	-	-	-

3.1 Inertia

While conventionally expressed in terms of GWs or MWs (Ørum *et al.*, 2017), the inertia is, in this work, expressed in terms of power needed to cope with a dimensioning fault (N-1). This is to avoid inertia time constants (H) for technologies providing synthetic inertia, and for easier comparison to provision of fast frequency reserves (FFR). FFR is not explicitly studied in this work, but the synthetic inertia is implemented such that it can be considered FFR when delivered from batteries. The assumed H-values are based on Ørum *et al.* (2017) and can be found in Table 3 below along with the resulting increased power output during a dimensioning fault. The latter was calculated using Equation 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 constants, f the nominal frequency of the grid and ΔP the change in power output from the generator.

Table 3. Assumed inertia constants and resulting power response per technology type for synchronous generators. The power response is expressed as the increased output as 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

In addition to the generators shown in Table 3, batteries, flywheels and wind power are also 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 capacity allows, 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 findings by Imgart and Chen (2019)). Hydrogen storage systems are assumed to be too slow to provide power for inertia responses due to the nonsynchronous nature and need for mass transportation to function, but can provide reserve power.

For every timestep, the total available inertia response needs to at least cover the dimensioning fault (N-1). These values are listed in Table 4 and were calculated in two steps. First, initial values for reasonable largest power plant block sizes were chosen by looking at the technology mix in the base case for each region. It was then found that the proportion between the largest power block size and yearly electricity demand was similar for all regions (between 15 and 20 MW*yr/TWh) except for *Hydro+wind* where the ratio was about a third (6.5). Since the purpose of this study is to investigate the impact of inertia constraints in systems with different technology mixes, rather than systems with different sizes, the N-1 was adjusted to give the same ratio for each region investigated. For *Hydro+wind*, this N-1 value is similar to the currently dimensioning nuclear reactor in Sweden.

Table 4. Dimensioning fault (N-1) for the regional cases included in this work.

	Solar	*Inland*	*Wind*	*Hydro+wind*
N-1 [MW]	1 239	605	440	1 388

3.2 Operating Reserve

When there is an imbalance between electricity load and generation, some generation (or load) must be added or removed in order to restore balance and prevent the frequency from deviating further. Traditionally, this reserve generation has been categorized into primary, secondary and tertiary reserves, referring to the order in which they get activated following an imbalance. However, this categorization is based on traditional fuel-based systems and not necessarily suitable for future systems with high shares of VRE where different technical limitations to provide reserve capacity apply. Furthermore, the historic reserve levels may also be unsuitable as the share of VRE, electrified industries and 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 can not provide up-regulation without constantly curtailing some energy. It is thus assumed that down-regulation is significantly easier to handle than up-regulation in high-VRE systems and, thus, only up-regulation 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 seconds instead are covered by the inertia power response[1] and 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 each thermal unit can contribute with depends on whether the unit is online or offline and which interval is being considered. The fractions of rated capacity which can be added is given in Table 5, below. The ramp rates for online units are based on a study by Agora Energiewende (2017), and the start-up times are based on a study by Schröder *et al.* (2013). Furthermore, it is assumed that nuclear power in 2050 will be state-of-the-art in terms of ramping ability due to the system context they will be in.

Table 5. Fractions of rated capacity which can be ramped up for each intra-hourly reserve interval, O_o^{dur} (used in Equation 12). CC = combined-cycle, OC = open cycle, GT = gas turbine, ST = steam turbine, and CCS = carbon capture and storage.

	O_1^{dur}	O_2^{dur}	O_3^{dur}	O_4^{dur}	O_5^{dur}	O_6^{dur}	O_7^{dur}
	10–60 s	1–10 min	10-20 min	20-30 min	30-40 min	40-50 min	50-60 min
Energy storages							
Li-ion bat.	1	1	1	1	1	1	1

[1] In practice, the duration of inertial support or FFR may vary. However, the assumption of 10 seconds is reasonable from a modeling point-of-view due to the vast capacity for fast frequency control in the investigated scenarios. Further discussion on the topic can be found in Discussion.

Hydrogen	1	1	1	1	1	1	1
Flywheels	1	1	1	1	1	1	1
Hydro	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

The amount of required reserves is calculated as the sum of three sources: the dimensioning fault (N-1) as well as load variations and variations from VRE at an intra-hourly scale. The first two are exogenously given to the model[2], but the variations from VRE will increase as VRE investments increase. The N-1 size is assumed to be constant throughout the year (see previous section) while the reserve demand from load variations vary each day and the demand from VRE variations vary 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 was estimated using a heuristic formula, and parameters for continental Europe, from the UCTE Operation Handbook parameters:

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

Where R_i are the (secondary) reserves required for day i with daily max load $L_{i,max}$ and the parameters a and b are 10 and 150 MW, respectively.

3.3 Electricity system model

The model used in this study is a linear investment and dispatch electricity system model with time-resolution of 1 hour 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 assuming transmission within the region is without congestion (i.e. no interregional or intraregional transmission is modeled). Unit-commitment has been linearly approximated as in (Weber, 2005; Hua, Baldick and Wang, 2018). A mathematical formulation of the model can be found in Göransson *et al.* (2017), with additions regarding VMSs described in Johansson and Göransson (2020). This work has added several equations, variables and parameters in order to capture the demand and supply of OR and inertia. This section includes a basic mathematical description of the model followed by the

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

additions made in this work. All sets, variables and parameters used in the description of the modeling can be found in Table 6.

Table 6. Sets, variables and parameters used in the equations describing the modeling.

Sets

R	Regions, {1,..,4}
T	Timestep, {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 timestep *t* in region *r*	[GWh/h]
$s_{r,t,p}^{charge}$	Charging of storage *p* in region *r* at timestep *t*	[GWh/h]
$s_{r,t,p}^{discharge}$	Discharging of storage *p* in region *r* at timestep *t*	[GWh/h]
$as_{r,t,p}^{inertia}$	Available inertial power	[GW]
$as_{r,t,p,o}^{OR}$	Available operating reserves	[GW]

Parameters

η_p^{ESS}	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_p^{inv}	Investment cost for technology p	[k€/GW]
C_p^{OPEX}	Running cost (fuel and variable O&M) for technology p	[k€/GWh]
C_p^{start}	Start-up cost for technology p	[k€/GW]
C_p^{part}	Part-load cost	[k€/GW]
$I_{r,t}^{load}$	Power reserve demand due to intra-hourly load variations	[GW]
I_r^{N-1}	Power reserve demand to cover for worst single fault (N-1)	[GW]
I^{dur}	Duration of inertia power response (10 s)	[s]
I_p^{sync}	Inertial power response from synchronous generators (see Table 3)	[-]
$O_{p,o}^{on}$	Ability of technology *p* to increase output until reserve interval *o*	[-]
$O_{p,o}^{off}$	Ability of technology *p* to start up until reserve interval *o*	[-]
O_o^{dur}	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_p^{rate}	Storage (dis)charge rate as a fraction of storage per hour	[-]

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 (c^{tot}) 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 (g^{active}) and capacity being started up (g^{start}) as described in Weber (2005) and Hua, Baldick and Wang (2018). This means that generators can be run at part-load and be subjected to start-up costs and time. Equation 2, below, expresses the total system cost being minimized in the model.

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

As shown in Equation 3, the net electricity generation, considering storage charging and discharging, has to meet an exogenous demand, $D_{r,t}$, at each timestep. However, the generation is limited, for each technology, by the online capacity ($g_{r,t,p}^{active}$) which in turn is limited by the installed capacity in Equation 4. The right-hand-side in Equation 4 also contains the generation profile ($G_{r,t,p}$) which limits the hourly production for VRE technologies. For all non-thermal technologies, $g_{r,t,p}^{active}$ has no meaning and does not impact the operation. The operation of storage is limited by the state-of-charge according to Equation 5 and by the investments in power capacity according to Equation 6. In Equation 6, the p and q represent energy storage technologies and their respective power capacity investments for charging and discharging.

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

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

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

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

These equations make up the core of the model expanded upon in this work. A complete description including all equations can be found in Göransson *et al.* (2017) and Johansson and Göransson (2020). The remaining of this section will detail the additions to the model.

Similarly to production meeting the power demand, inertia power response, $as_{r,t,p}^{inertia}$, and OR, $as_{r,t,p}^{OR}$, also must meet a minimum level required to ensure sufficient frequency control as shown in Equations 7 and 8. In the equations below, $I_{r,t}^{load}$ refers to the intra-load variations described in section Operating Reserves, and I_r^{N-1} refers to the N-1 values in Table 4.

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

$$\sum_{p \in P} as_{r,o,t,p}^{OR} \geq I_{r,t}^{load} + I_r^{N-1} + \sum_{p \in P^{VRE}} i_{r,p} * max\left(\left|G_{r,t,p} - G_{r,t-1,p}\right|, \left|G_{r,t+1,p} - G_{r,t,p}\right|\right), \quad \forall r, o, t \in R, O, T \tag{8}$$

In Equation 8, $i_{r,p} * max\left(\left|G_{r,t,p} - G_{r,t-1,p}\right|, \left|G_{r,t+1,p} - G_{r,t,p}\right|\right)$ represents the hour-to-hour variations of VRE, i.e. how much the production may be ramped up/down during the timestep. The variable for spinning capacity, $g_{r,t,p}^{active}$, is further constrained to approximate start-up cost, start-up time, minimum load and part-load operation using continuous variables (the complete thermal cycling approximation can be found in Göransson *et al.* (2017)). Additionally, $g_{r,t,p}^{active}$ also determines how much inertia power response, $as_{r,t,p}{}^{inertia}$, and OR, $as_{r,t,p}^{OR}$, is available for synchronous technologies according to Equations 9-10.

$$as_{r,t,p}^{inertia} \leq g_{r,t,p}^{active} * I_p^{sync}, \qquad \forall r, t, p \in R, T, P^{inertia} \tag{9}$$

$$as_{r,t,p,o}^{OR} \leq (g_{r,t,p}^{active} - g_{r,t,p}) * O_{r,p,o}^{on} + (i_{r,p} - g_{r,t,p}^{active}) * O_{r,p,o}^{off}, \quad \forall r, t, p, o \in R, T, P^{OR} \tag{10}$$

The batteries and flywheels are also able to provide synthetic inertia (depending on the scenario) and reserves. The two factors limiting the ability of storages to provide this is (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 through Equations 11-12 below. The limitation from storage level (ii) is implemented according to Equation 13 for inertia, and according to Equation 14 for reserves:

$$as_{r,t,p}^{inertia} - s_{r,t,p}^{charge} + s_{r,t,p}^{discharge} \leq i_{r,q} \leq \ i_{r,p} * R_p^{discharge}, \ \ \forall r, t, (p, q) \in R, T, Q \tag{11}$$

$$as_{r,t,p,o}^{OR} - s_{r,t,p}^{charge} + s_{r,t,p}^{discharge} \leq i_{r,q} \leq \ i_{r,p} * R_p^{discharge}, \ \ \forall r, t, (p, q) \in R, T, Q \tag{12}$$

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

$$\sum_{o \in O} as_{r,t,p,o}^{OR} * \frac{O_o^{dur}}{3600} \leq g_{r,t,p} * \eta_t^{ESS} + s_{r,t,p}^{charge} - s_{r,t,p}^{discharge}, \qquad \forall r,t,p \in R,T,P^{ESS} \tag{14}$$

I^{dur} and O_o^{dur} are the lengths of each commitment and sum to 3600 seconds (1 hour) such that when inertia and all reserve intervals *o* are satisfied, the whole hourly timestep 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 discussed in section Discussion.

4 RESULTS

Figures 1 and 2 give the installed electricity generation, storage and synchronous condenser capacity for the five scenarios investigated for the *Inland* and *Wind* cases, respectively (corresponding results for *Solar* and *Hydro+wind* can be found in Appendix B). From the figures it can be observed that the installed capacity is very similar for all scenarios, indicating that requirements on capacity available for inertia and operating reserves have a small impact on the cost-optimal technology mix for electricity generation and storage. The most notable effect seen in terms of installed capacity happens in the scenarios with reserve requirements where more investments are made in battery storage and power.

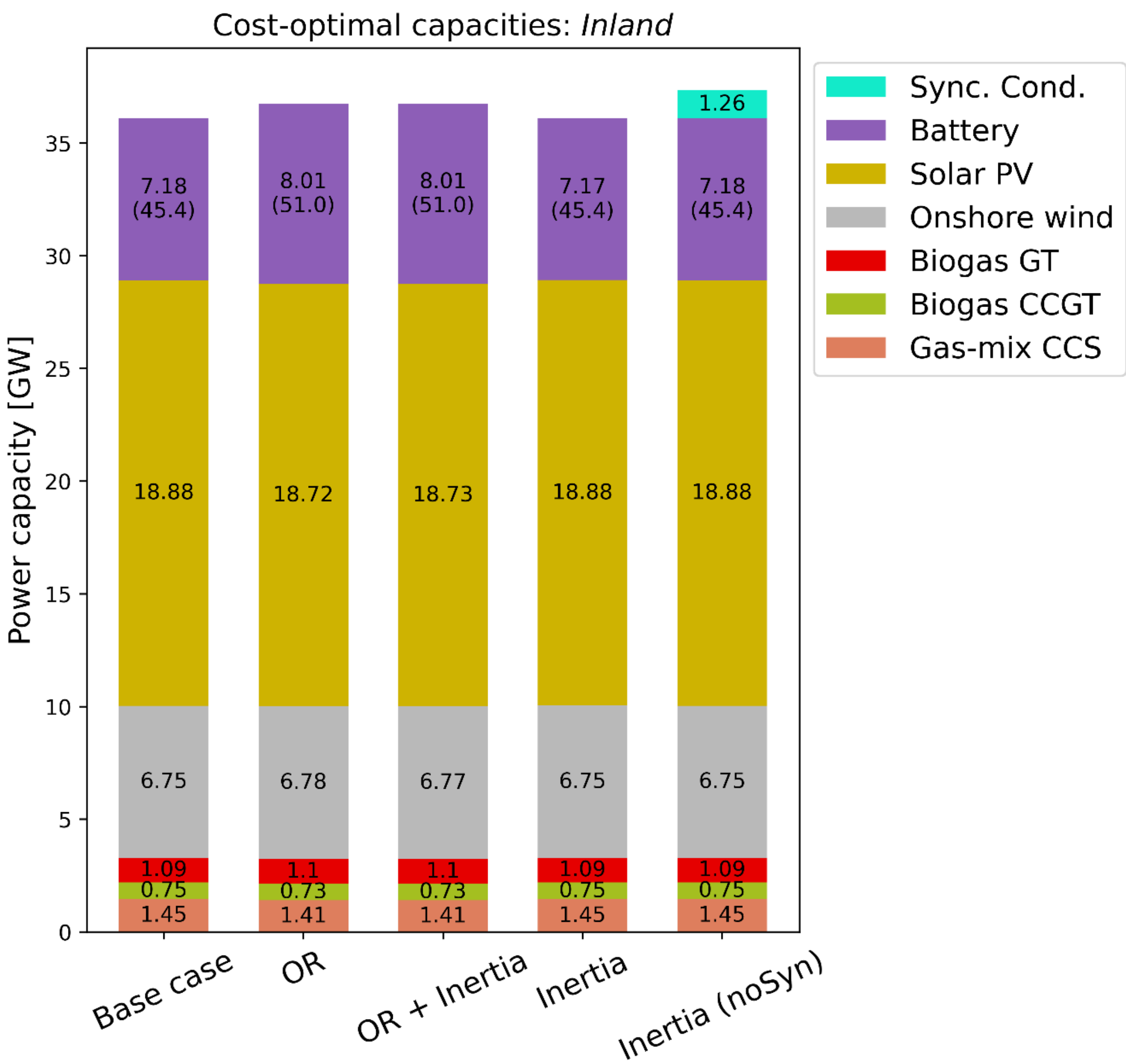

Figure 1. Cost-optimal installed capacity for *Inland* in all scenarios. Numbers displayed in parenthesis for batteries is the storage capacity in GWh.

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 inertia power response is even lower than the impact of requiring capacity for operating reserves since a higher amount is required for OR and the already installed battery and wind power capacity 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 to thermal options of inertia provision since it would be very costly for thermal plants to stay online some hours only to provide inertia.

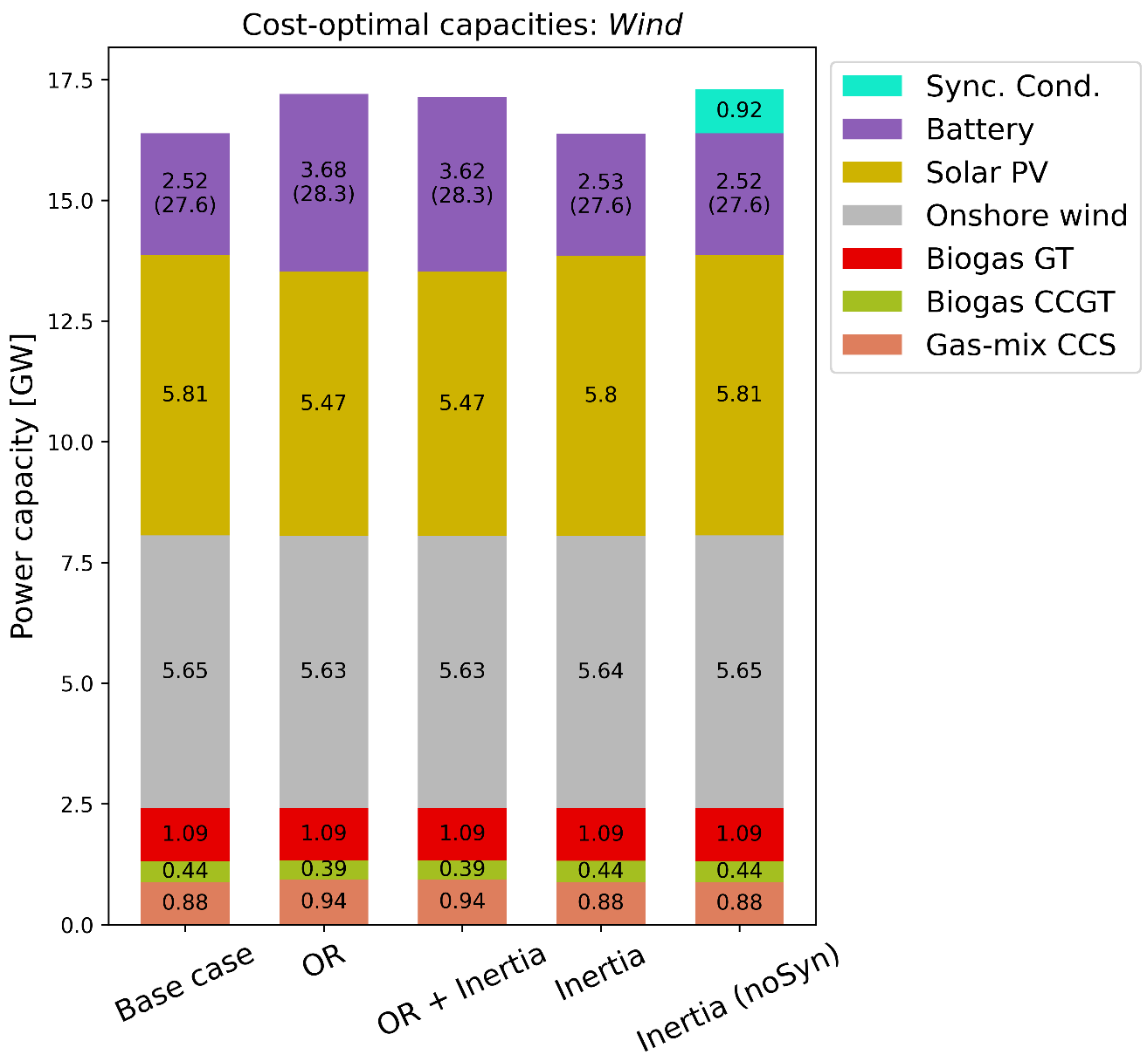

Figure 2. Cost-optimal installed capacity for *Wind* in all scenarios. The number displayed in parenthesis for batteries is the storage capacity in GWh.

Table 7 lists indicators for all scenarios and regional cases listed in the Methodology section. As can be seen, synchronous condenser and battery are the main providers of synchronous inertia and reserves, respectively. The low cost change shows that inertia constraints alone have almost no impact on the system when synthetic inertia is allowed. VRE share is separated into solar and wind share to show how the OR requirement causes a slight shift from solar to wind. The reason is that the reserve requirement is formulated to depend on hour-to-hour variations in VRE production. Thus, the required reserve amounts can be decreased by shifting investments away from solar PV which is especially variable.

Table 7. Summary of the scenarios by means of indicators. The main changes between the base case and each scenario are highlighted in bold text.

		System cost [G€/yr]	Cost change [-]	*Wind* share [-]	Solar share [-]	Curtailed energy [-]	Sync. Cond. 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
	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**
Inland	*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
	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**
Wind	*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
	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**
Hydro +wind	*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

Generally, an increase in battery storage capacity is the main change of investments in all regions when introducing OR constraints. While small changes in dispatch can be seen for some hours in *Hydro+wind*, the main source of reserves comes 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 *Hydro+wind* which has a large share of dispatchable generation and flexibility from reservoir hydropower). This benefit of double-use of the additional batteries can, in part, be found by comparing the investment and O&M costs imposed on the model from the battery investments with the difference in system cost. If the system cost increase 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 system cost is larger than the battery cost, then there must be other costs imposed from the OR requirements. The difference between these two costs are shown for the *Base* and OR case for all regions in Table 8 below.

Table 8. Comparison between the increased system cost and the battery cost for the OR scenario 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
Sys. cost incr. / Bat. cost	117 %	70 %	104 %	72 %

Table 8 shows that for *Inland* and *Hydro+wind*, there is double-use of the extra batteries since the system cost increase is smaller than the costs imposed from the extra battery capacity. However, in

Solar and *Wind*, 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 *Solar* comes from ramping solar PV output, imposing OR requirements causes a slight shift from solar PV to wind power (about 2 % of the yearly energy supply). This moves the system away from the cost-optimal energy mix and reduces the need for batteries as a VMS, hence the higher system cost increase for *Solar* in Table 8. While this shift also can be found in *Wind* and *Inland, Inland'*s poor wind and solar conditions lead to a higher benefit of extra batteries.

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

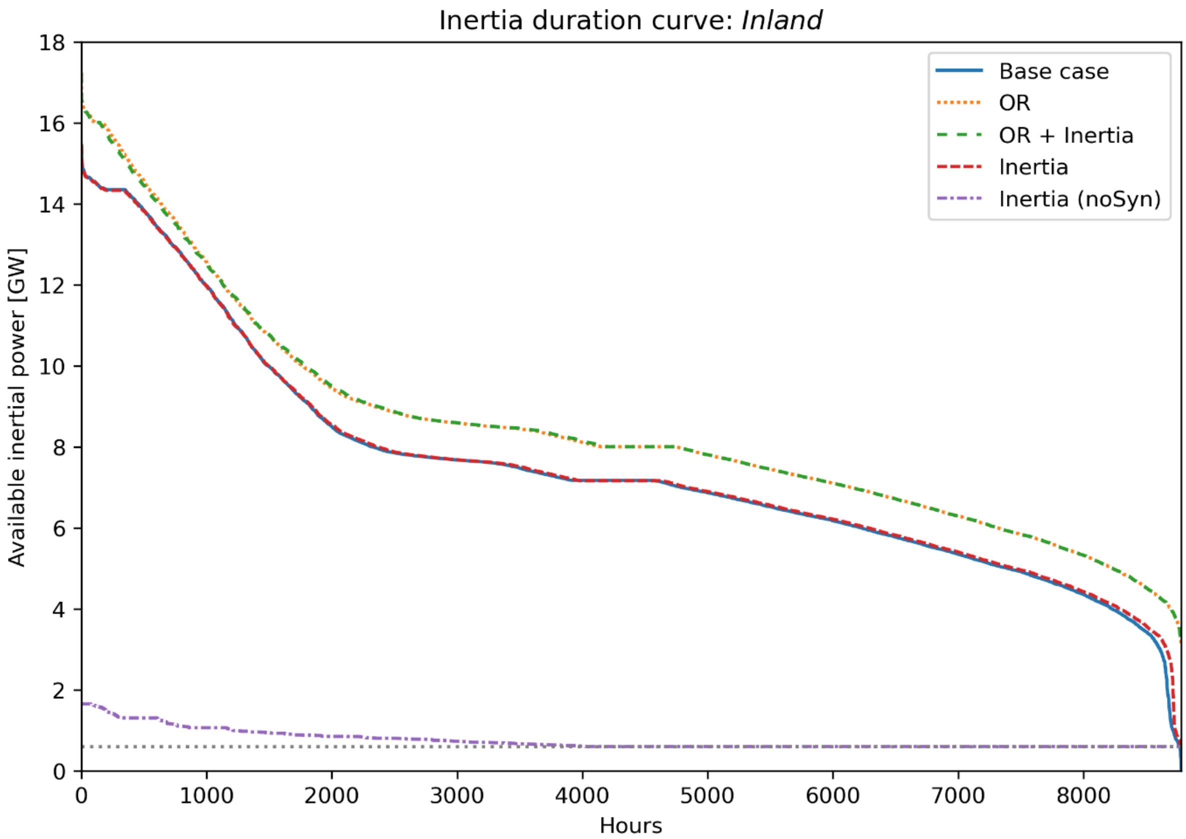

Figure 3. Duration curve showing available inertia in the *Base*, OR, *Inertia* and *Inertia (NoSyn)* scenarios for *Inland*. The dotted line shows the inertia requirement when applicable (605 MW).

Figure 4 shows generation, battery level (only usable battery portion) and available reserves for 2 days in *Solar* and 3 days in *Wind.* Comparing the operation and cause for insufficient reserves in *Wind* and *Solar* in Figure 4 highlights an important difference between wind- and solar dominated systems. In *Solar*, the lack of reserves happens during hours of empty battery storage as a consequence of discharging during a high net-load event (see hours 1735 and 1759, marked in red on the x-axis in Figure 4). However, in *Wind*, there is a lower battery power capacity since 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 hour 5972 and 6020 for *Wind* (marked in red on the x-axis). However, also in *Wind* occasions with insufficient reserves due to empty batteries occurs, as is shown during hour 6035.

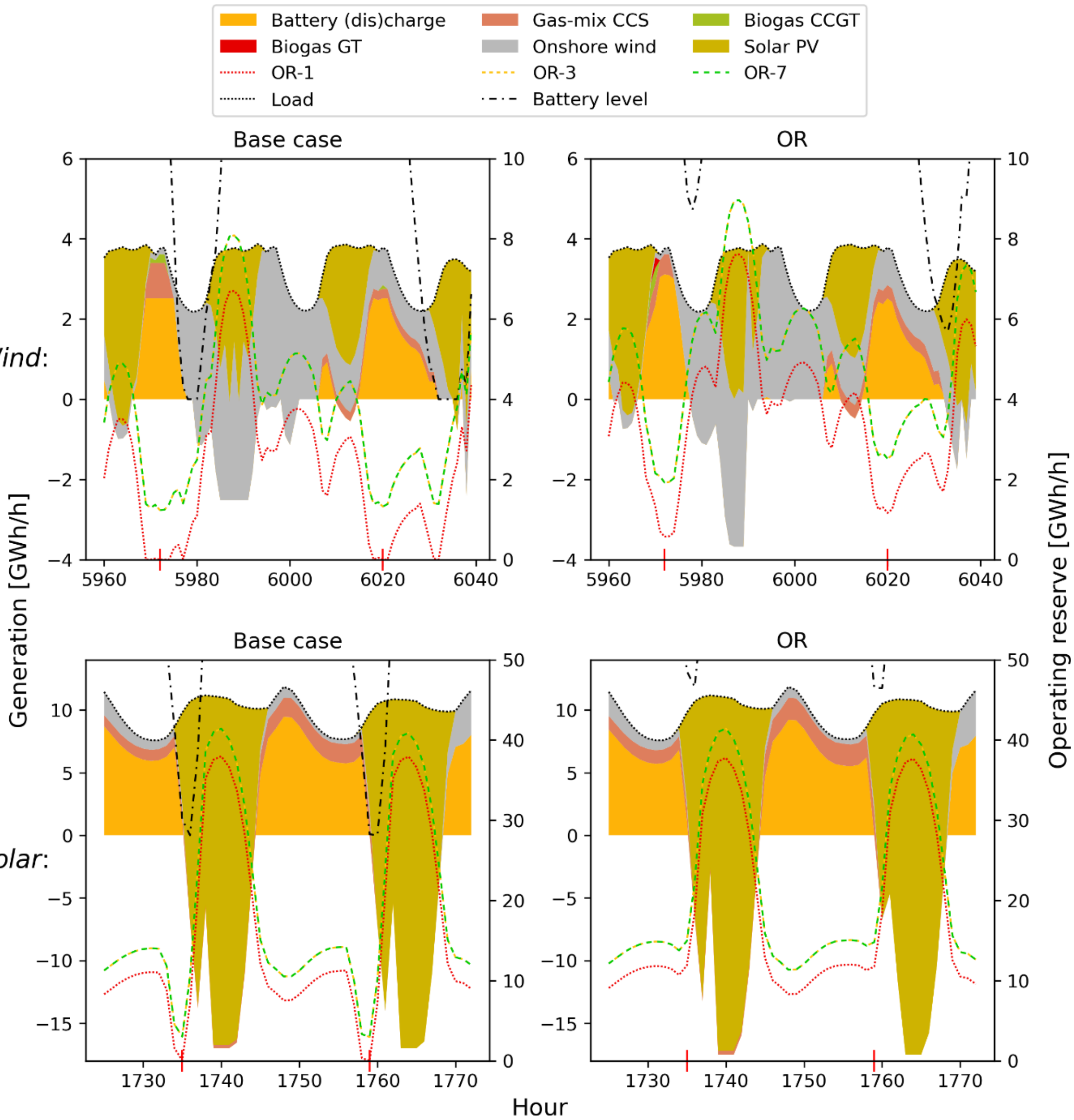

Figure 4. Generation, battery level (only usable battery portion) and available reserves for two days in *Solar* and 3 days in *Wind*. Note that generation below zero means batteries are being charged, and the state-of-charge continues above the border but has been cut off in the image.

Similar to the OR in Figure 4, the inertia in Figure 5 is not increased by a change in dispatch but rather from investments in batteries (as shown in Table 3). At hour 6368 (marked in red on the x-axis) the only difference between the *Base* and *Inertia* scenarios is that the increased battery capacity in *Inertia* allows the battery to still have about 1 GWh left at the nightly discharge cycle. It should be noted that changes in dispatch can be found, for example in *Solar* where thermals at one point replace battery discharge to allow batteries to provide fast reserves instead. In *Hydro+wind*, where there is both hydro reservoirs and batteries, there are also hours where the hydropower is discharging instead of batteries to increase inertia. Note that the large differences in timing for battery charging in Figure 5 (compare, for example, hour 6420 for *Inertia* and *Inertia (NoSyn)*) is caused by the excess curtailment enabling several same-cost solutions.

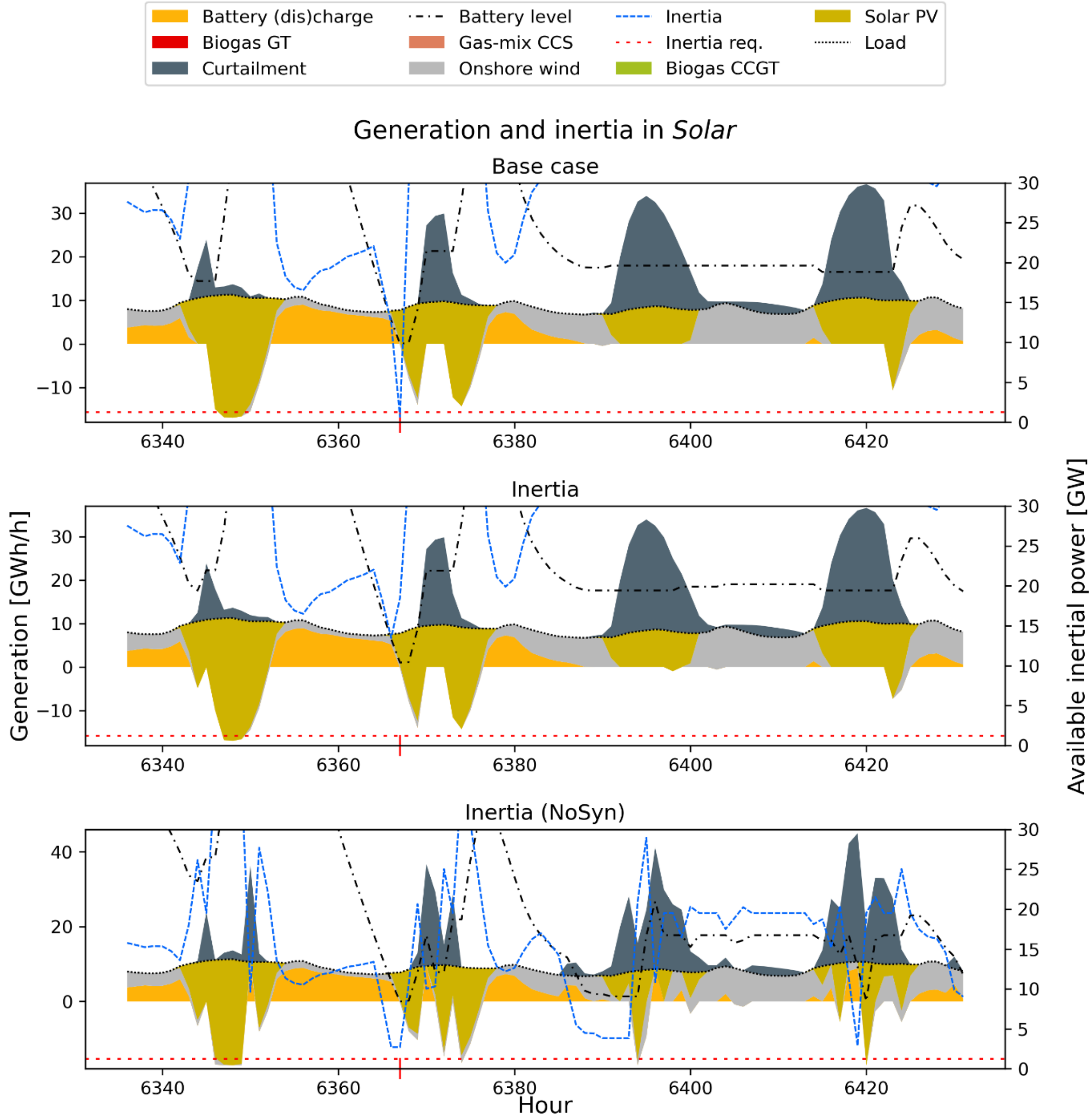

Figure 5. Generation, battery level and available inertia for a week in *Solar*. Note that generation below zero means batteries are being charged, and some lines continue above the boarder but have been cut off for visibility.

4.1 Sensitivity analysis

The results presented are not sensitive to synchronous condenser cost, as both a halving and a 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 *Wind, Solar,* and *Inland,* where their absence leads to a large replacement by synchronous condensers. In *Hydro+wind,* inertia from wind power plays a larger role than batteries but the absence of either leads to replacement by synchronous condensers.

Increasing battery investment costs affects the results by shifting all solutions away from batteries and VRE, towards thermal generation of electricity. However, an increased battery cost has little effect on the impact of adding inertia and OR constraints. When adding OR constraints, a higher battery cost slightly *increases* the additional battery investments since there is less preexisting 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 *Solar.*

5 DISCUSSION

Since the model used in this 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. On the other hand, the batteries are also never charged during intra-hourly periods of excess generation. It is assumed that the combined effect of these two factors is close to zero on the scale of several hours whereas the fastest storage cycles in the results are once per day (in *Solar*).

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 done 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 *Wind, Inland, Solar* and *Hydro+Wind,* respectively). When borne by the consumers, this cost corresponds to roughly 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 impacts the battery investments, especially in *Hydro+wind* and *Wind* 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 underestimated 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* cases.

The results from this work point to OR constraints being more influential than inertia when modeling high-VRE electricity systems. While it can be argued that the inertia constraint using a 10 second timeframe is too long, this would only be true if the inertial response primarily was supplied by synchronous machines. The *Inertia* scenarios show that all regions have battery capacity which can be made available for synchronous inertia supply. Hence, 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 a question of how and when to transition from thermal plant-based OR, which cannot be answered with the greenfield-model used in this study. Thus, it should be important to investigate this by means of further studies into 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.

6 CONCLUSION

Using a combined investment and dispatch model with high time-resolution, it is shown that requirements on inertial power and operating reserves have a very limited impact on system cost (0.5 to 1.6% change), composition and dispatch. Furthermore, investments play a significantly larger role than changes in dispatch. While this suggests that dispatch-only models are insufficient to capture reserve services on their own, this would only be true in the cost-optimal sense and in scenarios with high levels of VRE, curtailment and batteries. However, the investments are largely isolated to batteries and specifically focused on battery power capacity in wind-dominated systems and battery storage capacity in solar-dominated systems. Furthermore, the capacity to provide inertia during all hours of the year was found to already exist (mostly in the form of synthetic inertia) from energy purpose optimization. If synchronous inertia is mandated, all investigated regional cases invested in synchronous condensers with virtually no other change to the system. This suggests that inertia-requirements in electricity system modeling may be unnecessary unless explicitly studied.

To conclude, this work indicates that batteries combined with wind power are cost-efficient ways of providing reserves and inertia in future high-VRE energy systems.

7 ACKNOWLEDGEMENTS

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9 APPENDIX A

Table A1 shows economic and technical data used in the model. Wind and solar PV, as well as hydrogen and battery storage system data are based on Danish Energy Agency and Energinet (2017) while thermal and nuclear plant data are based on International Energy Agency (2016).

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

	Inv. cost [€/kW]	Fix 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

10 APPENDIX B

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

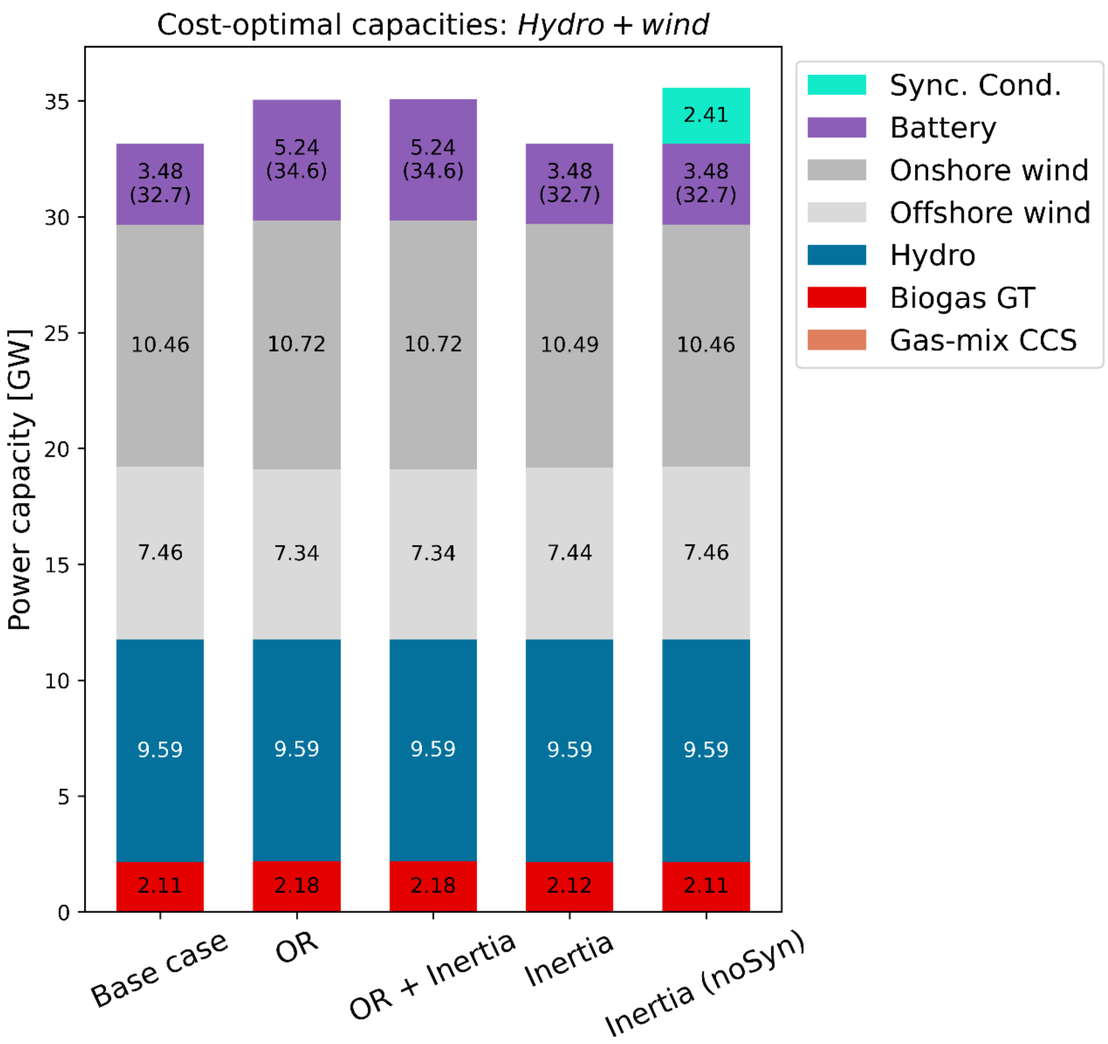

Figure B1, Cost-optimal installed capacity for *Hydro+wind* in all scenarios. Numbers displayed in parenthesis for batteries is the storage capacity in GWh.

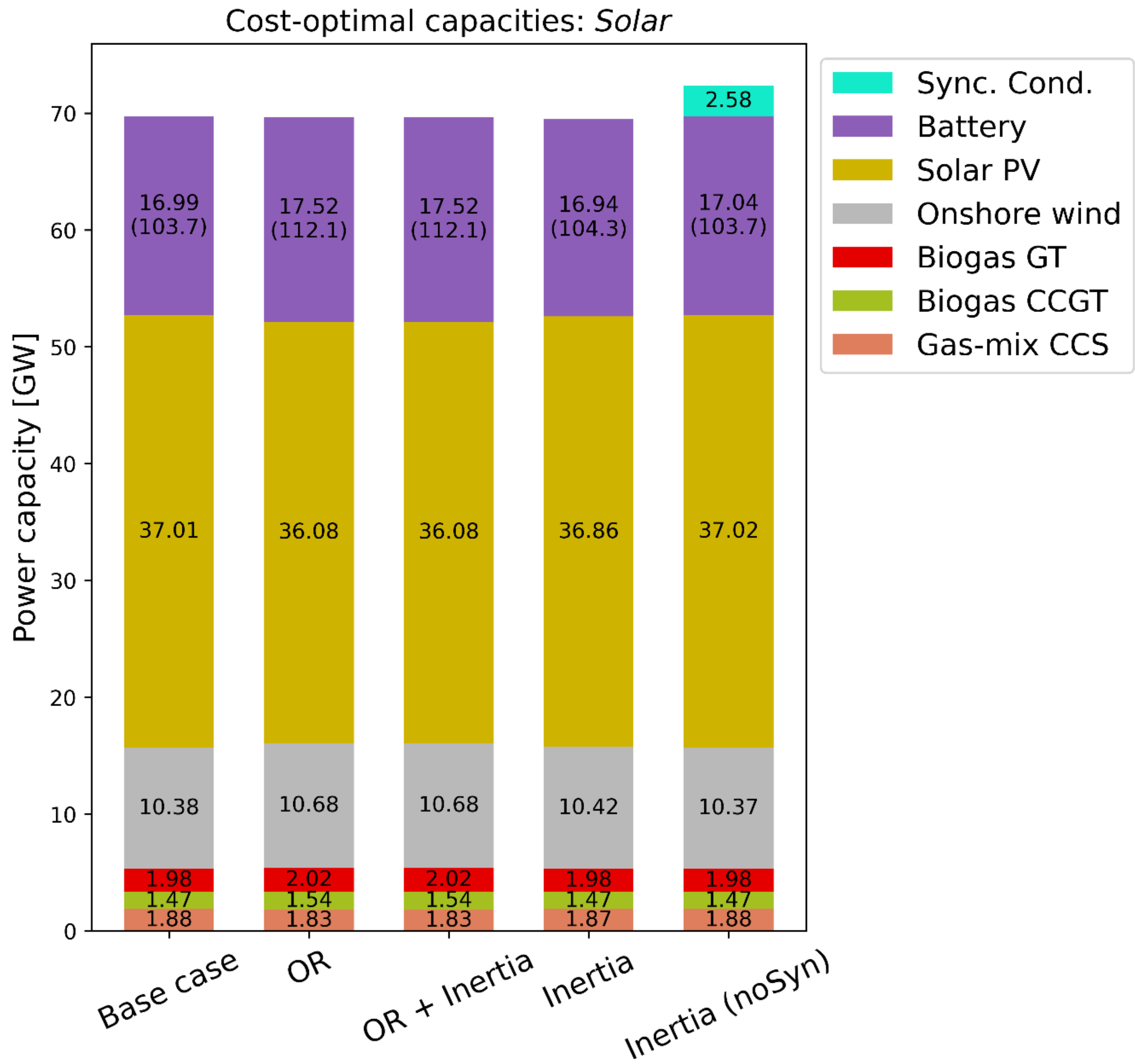

Figure B2, Cost-optimal installed capacity for *Solar* in all scenarios. Numbers displayed in parenthesis for batteries is the storage capacity in GWh.