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Generation Expansion Planning Considering Storage Systems and Inertia Constraints

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Abstract

Inertia issues due to the increased use of inertia-less renewable generation technologies (RGTs), such as photovoltaic and wind generation have gained increased attention during the last years. Their negative effects on frequency stability have already been experienced in some countries. To prevent these situations and ensure a secure integration of RGTs, apart from the natural inertial response of synchronous generators, there are basically two ways to improve the inertial response of a power system: by means of energy storage systems and by implementing virtual inertial response in RGTs through de-loaded operation. In this work, a modified swing equation is implemented in a 100% renewable generation expansion planning tool to demonstrate the importance of considering inertial constraints in the planning of future power systems. Our findings underline the necessity of taking into account the lack of inertia due to the increment of RGT's in the system and the necessity of storage investment due the lack of primary resource in some operating points to fulfill the demand requirement.

Keywords: optimization, BESS, frequency stability, inertial response, stability assessment.

1. Introduction

In order to reduce greenhouse gas emissions and stop global warming, many countries have committed to a transformation of their electricity systems into ones based on renewable energies. The large-scale incorporation of renewables generation technologies (RGTs) in power systems can not only help mitigating climate change, but can also provide wider benefits such as reducing overall power system operating costs and achieving independence of volatile fuel prices. This global drive towards renewable energies has already brought some concrete results. For example, 7% of China's total electricity demand in 2015 was supplied by renewable energies. According to IRENA (2018) this share could increase to 67% by 2050. In India, 36% of the total final energy use was also covered by renewable energies in 2015. This country has also the capability of increasing this share to 73% by 2050 (IRENA, 2018). The European Union has also achieved important results: together, their countries nearly doubled the share of renewable energies in the gross final energy consumption from 9% in 2005 to 17% in 2015 (IRENA, 2018). However, to meet long-term decarbonisation commitments the region would need to increase this share to 70% by 2050 (IRENA, 2018).

The transition of power systems from conventional ones dominated by synchronous generators (SGs) to future systems based on RGTs has still ongoing challenges in power system operation and control, especially from a frequency stability viewpoint (Tielens and Van Hertem, 2016). Frequency stability refers to the ability of a power system to maintain steady frequency following a severe disturbance between generation and load (IEEE/CIGRE Joint Task Force, 2004). Historically, frequency stability has been successfully sustained during major power imbalances through the inertial response of synchronous generators (SGs) and the control actions performed by their prime movers. In power systems dominated by SGs, the natural inertia of the rotating masses determines the immediate system frequency response during major power imbalances: the higher the system inertia, the slower the system frequency will vary (Rahmann and Castillo, 2014). This initial system response defines the rate of change of frequency (RoCoF) of the system, thus directly affecting the frequency performance. The system inertia has been therefore one of the key system parameters upon which the synchronized operation of power systems is based. However, this paradigm may no longer be sustained in modern power systems with high shares of RGTs connected through power converters due to their lack of inertial response (Rahmann and Castillo, 2014), (Tielens and Van Hertem, 2016). While photovoltaic (PV) power plants have no rotating parts to contribute with inertial

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response, variable speed wind generators are connected to the grid through power converters which decouple their mechanical response from the grid. Consequently, higher levels of inertia-less RGTs lead to a reduction of the overall inertia of the system, thereby affecting the frequency stability of the system.

In order to counteract the negative effects of low system inertia and thus improve power system frequency stability in modern power systems, a sound strategy is to allow RGTs and energy storage to provide virtual inertial response during the occurrence of a contingency (Tielens and Van Hertem, 2016). The concept of virtual inertia is to use the system frequency as input to the controllers and mimic the power response of the SGs. Allowing RGTs and energy storages to contribute with virtual inertial response during contingencies may be a key factor for ensuring frequency stability in 100% renewable power systems.

Based on the aforementioned context, in this work we investigate the optimal design of the Chilean power system in 2050 based on 100% renewable energies considering frequency stability constraints. To this end, we developed a generation expansion planning (GEP) tool that estimates the RoCoF of the system following a contingency and limits its value for ensuring frequency stability. While the natural system inertia is provided by existing hydropower plants, we allow RGTs and energy storages to contribute with virtual inertial response thus counteracting the effects of low natural system inertia. The remainder of this article is organized as follow. Section 2 presents the GEP model and Section 3 the study case. The results are presented in Section 4. Finally, section 5 concludes and lines out the future work.

2. Optimization model

2.1. Introduction to the GEP model

The GEP model presented in this work is based on the model of Haas et al. (2018). The objective of the model is to minimize the investment and operational costs of the system for a specific year in the future (static generation planning). The model finds the optimal mix (size and location) of storage and generation technologies, taking into account the existing hydropower plants (including flow routing). The transmission system is modeled with linear losses and it is assumed that all lines have enough capacity to prevent congestions. More details on the model can be found in Haas et al. (2018).

Our approach considers a one-year modeling horizon with hourly resolution (i.e. 8760 sequential time steps). We focus on 100% renewable systems, e.g. there are no fossil generators in our model, and neglect the unit commitment constraints. The model is able to consider different energy storage technologies, but in this case, we only consider Li-ion battery system as storage device due their excellent projection in the electrical market.

2.2. Frequency stability constraints

In the context of an electrical power system dominated by RGTs, we assume that these technologies have the capacity to deliver virtual inertial response by operating below their maximum capacity (e.g. in de-loaded mode) to keep a certain level of reserve in case of contingencies. This implies spilling (curtailing) power, and prescribes the maximum to-be-offered frequency stability constraints, as follows:

$$p_{r,z,t} + p_{r,z,t}^{spilled} = P_{r,z}^{ins} \cdot Profile_{r,z,t} \quad \forall r,z,t \qquad \text{(eq. 1)}$$

$$fRes_{r,z,t}^{R} \leq p_{r,z,t}^{spilled} \quad \forall r,z,t \qquad \text{(eq. 2)}$$

where $p_{r,z,t}$, $P_{r,z}^{ins}$ and $p_{r,z,t}^{spilled}$ represent the power output, the capacity installed and the power spilled for every renewable r in zone z in every time step t. $fRes_{r,z,t}^{R}$ and $Profile_{r,z,t}$ represent the reserve for inertial response and the renewable profile for every renewable r in zone z in every time step t.

In the case of BESS technology, its charge and discharge power together with the virtual inertial response reserves are limited by the installed power as well as the energy capacity. These variables must fulfill:

$$p_{s,z,t}^{discharge} + fRes_{s,z,t}^{S} \leq P_{s,z}^{ins} \quad \forall s,z,t \qquad \text{(eq. 3)}$$

$$p_{s,z,t}^{charge} \leq P_{s,z}^{ins} \quad \forall s,z,t \qquad \text{(eq. 4)}$$

$$\left(p_{s,z,t}^{discharge} + fRes_{s,z,t}^{S}\right) \cdot \Delta t \leq stored_{t,s} \quad \forall s,z,t \qquad \text{(eq. 5)}$$

where $p_{s,z,t}^{discharge}$, $p_{s,z,t}^{charge}$, $P_{s,z}^{ins}$ and $fRes_{s,z,t}^{S}$ represent the power discharge and charge, the capacity installed and the reserve for inertial response for every storage s in zone z in every time step t.

2.3. Inertial response constraint

Considering a scenario with high levels of RGTs, it can be assumed that virtual inertial response will be required by different grid codes in order to ensure system frequency stability. In this context, several countries have already introduced different RoCoF requirements. For example, United Kingdom have imposed a limit of 0,125 [Hz/seg] (Hung et al. 2010). The Nordic System and Ireland have imposed a limit of 0,5 [Hz/seg] (Díaz-González et al. 2014 and Bomer et al. 2010). Thus, in order to propose a frequency constraint that considers the contribution of BESS and RGTs, we start with the swing equation as a base:

$$\frac{df}{dt} = \frac{f_0}{2H_{sys}}(\Delta P_m - \Delta P_e) \qquad \text{(eq. 6)}$$

Variables ΔP_m and ΔP_e represent the deviation in the total mechanical and electrical power, respectively. In this case, since we are not considering the primary frequency control, ΔP_m is 0. H_{sys} represents the total system inertia given by the synchronous machines and can be calculated as:

$$H_{sys} = \frac{\sum_{i=1}^{N} H_i \cdot S_i}{S_b} \qquad \text{(eq. 7)}$$

where H_i and S_i represent the inertia constant and the nominal power of every synchronous machine. S_b is the chosen common base of the system.

Given that RGTs and BESS cannot contribute to physical inertia, their virtual inertial support is used to counteract the electrical unbalance ΔP_e. In this sense, equation 6 can be expanded by incorporating the contribution of BESS and RGTs as follows:

$$\frac{df}{dt} = \frac{f_0}{2H_{sys}}\left(-\Delta P_e + \sum_{z_i,s} fRes_{t,z_i,s}^{S} + \sum_{z_i,r} fRes_{t,z_i,r}^{R}\right) \geq -0.125 \text{ [Hz/seg]} \qquad \text{(eq. 8)}$$

where ΔP_e is the power imbalance following an outage in the largest generator of the system (hydropower in our case, equal to 689 MW) and f_0 represents the nominal frequency of the system. Eq. 8 restricts the maximum permitted RoCoF value to 0.125 [Hz/seg].

3. Case study

We design Chile’s power system for the year 2050, where the model uses four representative zones to characterize Chile (Fig. 1): south, center, northern center and north. Each zone includes three profiles for both wind and solar technologies which are extracted from wind power explorer (2012) and solar energy explorer (2012). Only zones 1 and 2 have installed hydro technology. From figure 1 it can be seen that zones 3 and 4 have an outstanding solar profile, and zones 1 and 3 an outstanding wind profile. The yearly load profiles (with hourly resolution) of each zone are based on data of the National electrical coordinator of Chile and Alvarez et al. (2017). These are then projected to 2050 using the growth rates given by Chile’s National Energy Commission. This results in a total average demand of 23 GW and a total peak load of 29 GW. Table 1 summarizes the costs and lifetime used for BESS and RGTs.

Tab. 1: Costs and lifetime used for ESS and RGTs

Technology	Investment costs [k€/MW]/[k€/MWh]	Lifetime [Years]
Wind	900	25
PV	330	40
BESS	25/71	10

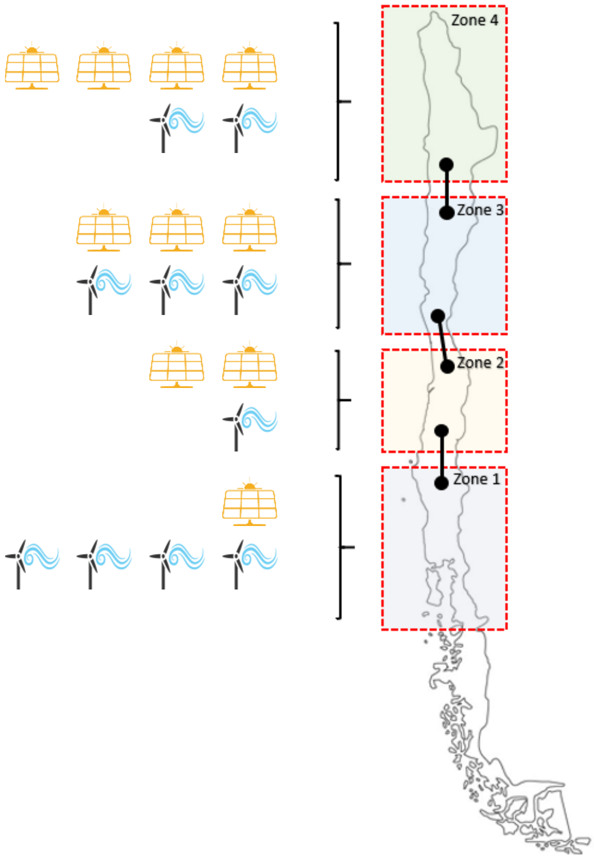

Fig. 1: Division of the Chilean electrical power system and their corresponding levels of renewable source.

To evaluate the influence of including inertial response constraints in the GEP problem for different cases of natural system inertia, we considered 4 scenarios of hydropower capacity in Chile for the year 2050. The base case assumes 6 GW of hydropower, which corresponds to the current hydropower capacity. The other scenarios consider 12 GW, 18 GW, and 24 GW of hydropower, respectively. These scenarios represent different levels of synchronous generation and are used to evaluate how the change in the system natural inertia can affect the stability of the system due the massive integration of RGTs. For each of these scenarios, we solved the GEP optimization problem for 5 different cases regarding the implementation of the swing equation in the GEP: i) without the swing equation (NS) –which serves as base case-, ii) with swing equation but without inertia contribution from BESS or renewables (WS) –as a way for evaluating a worst-case regarding the system frequency response-, iii) with swing equation considering only the inertia contribution of BESS (WS-B) –to assess an upper bound of the role of storage technologies-, iv) with swing equation considering only the inertia contribution from renewables (WS-R) –similar to iii–, and v) with swing equation considering both inertia contribution from renewable and BESS (WS-A) –which we think is going to be the most likely case in the future. Additionally, all those cases are analyzed when the projected costs of the PV and wind technologies changes. Figure 2 resume all the scenarios under study.

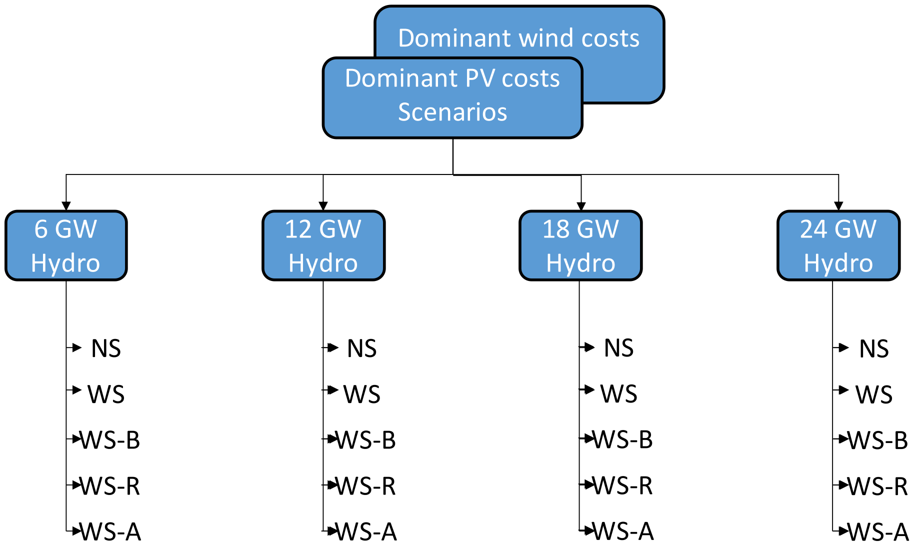

Fig. 2: Resume of all scenarios under study.

4. Results

4.1. PV as a dominant technology: Storage requirement

The total installed capacity of the projected system at the year 2050 for each hydropower scenario and each case of implementation of the swing equation (cases i to v), where the projected costs of the PV technology are lower than wind technology are shown in Figure 3. From the results it can be seen that if the total hydropower installed capacity of the system is less than 18 GW, the projected system is unable to comply with the inertia constraint if only synchronous machines contribute with inertial response during contingencies (case WS for 6 GW and 12 GW hydropower installed capacity). This implies that, in case of power systems with low inertia-levels (low level of synchronous generation and high RGTs penetration), the inertia contribution of BESS and/or renewables is mandatory to keep the RoCoF within acceptable limits. Otherwise, contingencies involving major power imbalances may lead to the activation of under-frequency load shedding schemes with inherent cost consequences. In these cases of low natural system inertia, allowing BESS to contribute with inertial response (cases WS-B and WS-A) results in a reduction of the total system generation capacity, compared to the case where only RGTs can contribute to the inertial response (case WS-R). The reason for this is that, in scenarios of high levels of RGTs, a significant amount of BESS is needed to fulfill the energy demand, especially in hours with a low solar generation profile. Thus, in the case where only RGTs are allowed to contribute with virtual inertial response (case WS-R), a significant amount of RGTs generating capacity is needed to cover the inertial constraint.

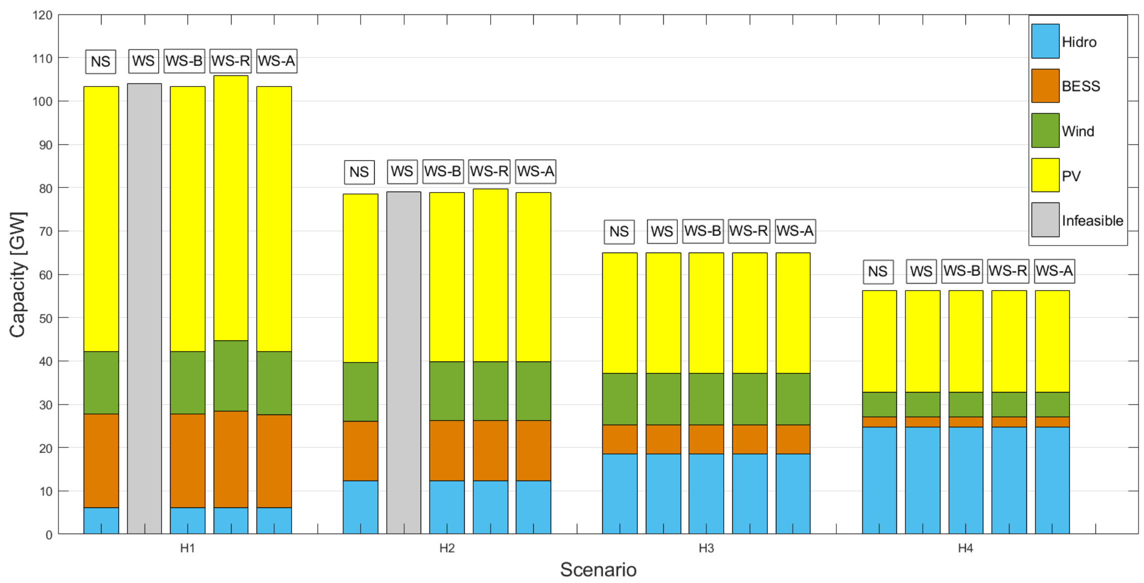

Fig. 3: Installed capacity of technology for all submodels and hydro scenarios.

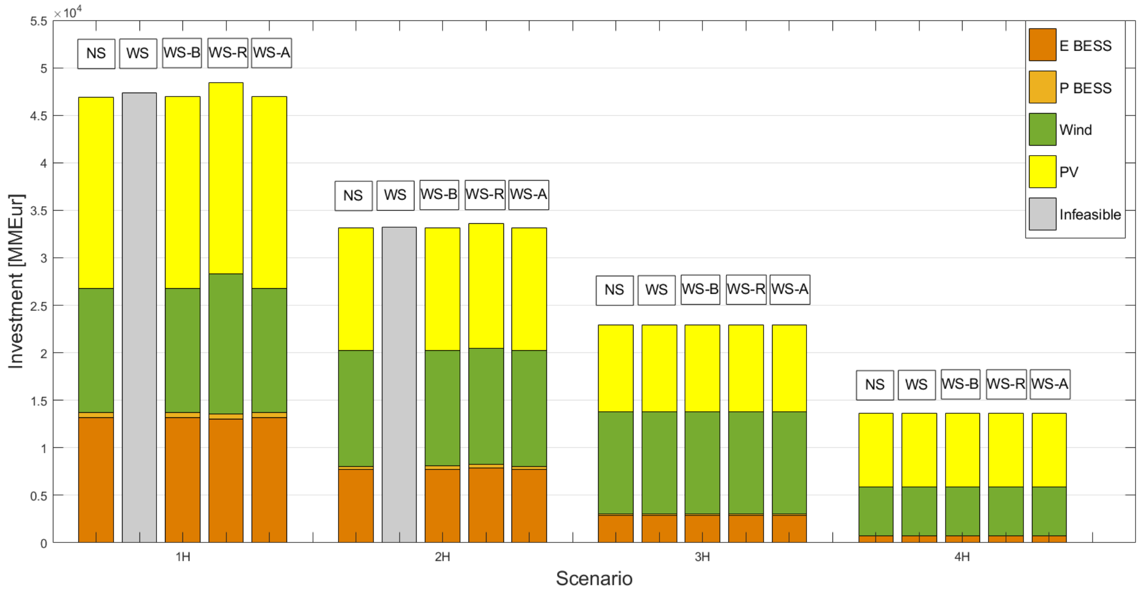

Fig. 4: Investment per technology for all submodels and hydro scenarios.

For scenarios with high levels of inertia (18 GW and 24 GW hydropower installed capacity), including the inertia constraint has a marginal effect on the optimal generation expansion planning solution. The reason for this is that the system inertia in these cases is enough to keep the RoCoF within acceptable limits.

Finally, when BESS are allowed to provide virtual inertial response, the difference in BESS technology investments among different sub-scenarios is only marginal. The reason is that the BESS capacity needed for balancing the net energy is also sufficient to provide the required inertial response. This allows BESS devices to maintain enough reserves to provide inertial responses if is needed. Consequently, no additional BESS and RGTs investments are needed to fulfill the frequency stability constraints.

4.2. Wind as a dominant technology: Less total investment

Figure 5 shows the total installed capacity of the projected system at the year 2050 for each hydropower scenario and each case of implementation of the swing equation (cases i to v), where the projected costs of the wind technology are lower than the PV technology. From this figure and Fig. 3 it can be seen that both study cases have the same behavior in terms of capacity, where a higher investment is required when only RGTs provide virtual inertial response. In scenarios with high natural system inertia (16 GW and 24 GW hydropower installed capacity), the frequency constraints do not change the optimal installed capacity. However, in scenarios with low systemic inertia level (6 GW and 12 GW hydropower installed capacity), the solution envisages lower investments in BESS technology (5 GW and 3 GW respectively) compared with the previous study case (Fig. 3 vs Fig. 5).

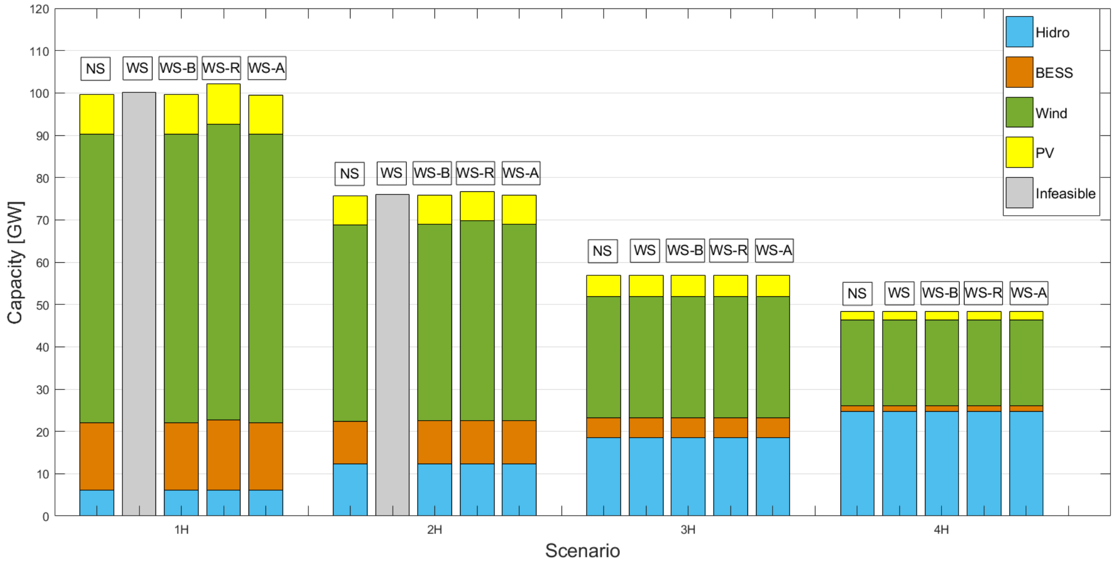

Fig. 5: Installed capacity of technology for all submodels and hydro scenarios.

The reason why a future scenario with lower wind costs than solar requires less investment of RGTs and BESS is due to the requirement to supply the electrical demand of the system, especially during night hours. In previous study case (PV as dominant technology) large amounts of energy storage are required to supply the electrical demand due to the lack of solar energy during the night (no sun). This results in higher investment costs, compared to the case where Wind is a dominant technology (see figures 4 and 6).

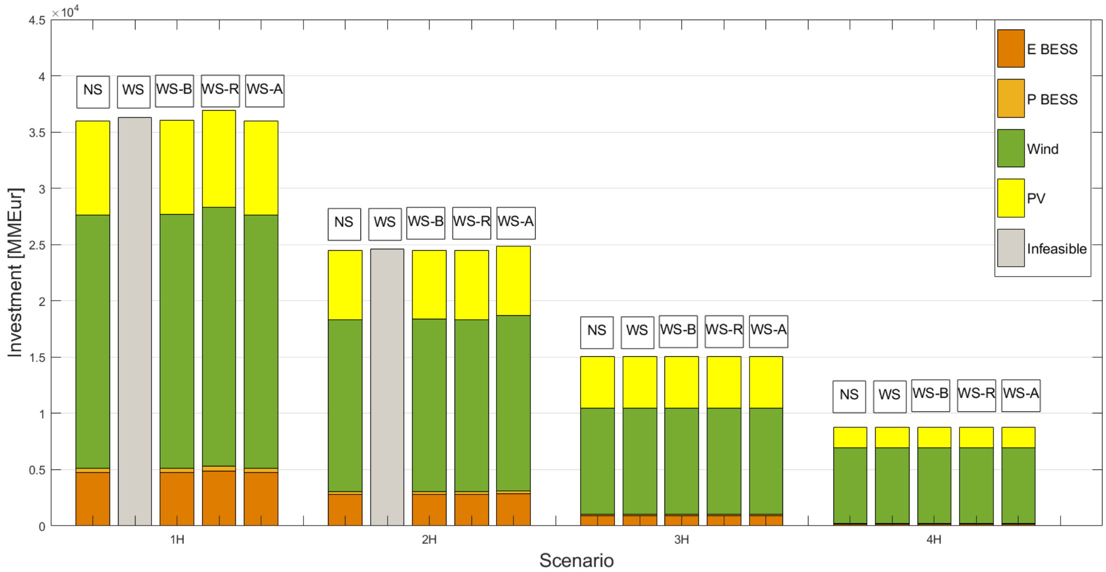

Fig. 6: Investment per technology for all submodels and hydro scenarios.

4.3. Discussion

The results obtained show the importance of both: considering frequency stability constraints in the design of future power systems based on 100% renewable energies, and to find proper strategies to counteract the negative effects of low system inertia and thus improve power system frequency stability. Indeed, in all scenarios of low natural system inertia that were analyzed, the resulting system was unable to comply with the inertia constraint if only synchronous machines contribute with inertial response during contingencies. This situation can be avoided with little additional costs by allowing RGTs and/or energy storages to contribute with virtual inertial response. Moreover, the results indicate that the most cost-efficient strategy is to allow energy storages to contribute with virtual inertial response, since the BESS capacity needed for balancing the net energy is also sufficient to provide the required inertial response. However, for RGTs and energy storages to contribute with virtual inertial response in future power systems, a proper regulatory framework and market design are needed. For this purpose, our proposed model can be used by energy regulators to analyze the impact of low system inertia and quantify its requirements, thus contributing to the cost-efficient and secure integration of renewable energies.

5. Conclusions

This work presents the optimal design of the Chilean power system in 2050 based on 100% renewable energies considering frequency stability constraints. We show that in power systems with low inertia levels, allowing BESS and/or RGTs to contribute with inertial response after the occurrence of a contingency it is mandatory to keep the RoCoF within acceptable limits and thus ensure system frequency stability. We also show that allowing BESS to contribute with virtual inertial response may lead to more economic system designs, compared to the cases where only renewables deliver inertial response. The reason is that the optimal BESS capacity needed to fulfill the energy balance throughout the year is enough to keep the RoCoF within the acceptable limits.

The results obtained for two different cost projections regarding wind and solar technologies show that, if PV becomes the dominant technology in terms of investment costs, more capacity of BESS and RGTs is required, which leads to higher overall system costs. The main reason is the fact that the primary resource of PV technology is distributed over certain periods of time (day hours). Consequently, more amounts of BESS investment is required to supply the electricity demand during night hours. Although in this case allowing BESS to provide virtual inertial response is enough to fulfill inertia requirements, it is necessary to look for other alternatives to diversify the energy matrix and not be so dependent on a single energy source. This is proposed as future work to look new alternatives for a 100% renewable system.

The successful deployment of inertial response from storage devices and renewables in future power systems requires the corresponding definition of market rules related to ancillary services, in order to provide the necessary incentives to undergo this path. Understanding these market-related issues is proposed as future work.

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