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Author(s):
Lütolf, Philipp; Scherer, Marc; Mégel, Olivier; Geidl, Martin; Vrettos, Evangelos

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Rebound Effects of Demand-Response Management for Frequency Restoration

Philipp Lütolf
ETH Zürich
Switzerland
pluetolf@ethz.ch

Marc Scherer, Olivier Mégel, Martin Geidl
Swisscom Energy Solutions Ltd
Switzerland
{ marc.scherer, olivier.megel, martin.geidl }@swisscom.com

Evangelos Vrettos
Lawrence Berkeley National Laboratory
USA
evrettos@lbl.gov

***Abstract*—This paper analyzes how demand-response aggregators, which provide active power reserves, affect frequency control. A rebound effect can occur when the modulation of energy consumption leads to an increased consumption after activation of the reserve. The technical basics are presented together with a model incorporating Continental European control structures including demand-response aggregation, both implemented in SIMULINK. The focus is placed on thermostatically controlled loads, which are typical for real-life demand-response aggregation for the provision of ancillary services. We investigate scenarios with forced outages, ramping behavior, and historical reserve activations. The results imply a negligible impact of the rebound effect in normal operation. Under worst-case assumptions, however, the rebound effect causes power oscillations leading to instabilities in the entire power system.**

***Index Terms*—Automatic generation control, demand-response aggregation, frequency control, rebound effects.**

I. INTRODUCTION

Nowadays, national system operators are responsible for frequency control either as Independent System Operators (ISOs), who merely operate the system, or as Transmission System Operators (TSOs), who operate and own the transmission system. Active power reserves for frequency restoration are assessed and dimensioned in line with international standards and minimum requirements [1]–[3]. Several studies have been carried out comparing regional ancillary service markets, their reserve deployment, and control structures [4], [5]. An overview of European control parameters is given in [6] and a discussion of different providers and activation schemes for Automatic Generation Control (AGC) in [7] and [8]. Reduced power systems models for capturing frequency control and market participant behavior showed good performance and results of high practical relevance [9]. The legacy of demand-response concepts is comprehensive [10]; however, their use to provide ancillary services is rather recent, and practical projects in demand-response aggregation often are a matter of economic viability [11]. Demand management for the provision of ancillary services usually requires a more complex IT infrastructure than the provision of services from conventional power plants [12]–[14]. Geidl et al. [15] presented a real-life implementation of 10000 aggregated electric heating devices for the provision of active power reserves in the Swiss ancillary service market.

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Our focus is on modeling the impact of rebound effects of demand-response services used for frequency restoration in a liberalized market. In this context, the contribution of this paper is twofold: Modeling the impact of demand-response aggregation and assessing rebound effects. We rely on a reduced power system model which captures the frequency control structure and reserve activation logic of Continental Europe.

This paper is organized as follows: Section II elaborates the frequency control basics for investigating the impact of demand-response services on frequency restoration. Section III presents the simulations and results for Continental Europe. Finally, Section IV is devoted to findings and perspectives.

II. METHODS AND MODELING

A. European Frequency Control Structures

In most interconnected power systems, frequency control is a three-tiered approach which involves frequency containment (“primary control”), frequency restoration (“secondary control”), and reserve replacement (“tertiary control”). The associated capacities are referred to as active power reserves or control reserves.

Frequency Containment Reserves (FCR) for frequency-response are the joint responsibility of all TSOs in a synchronous area. Frequency Restoration Reserves (FRR) imply a local responsibility of each TSO for the imbalance in its control area. In Continental Europe, automatic frequency restoration is performed by AGC, which is also referred to as Load-Frequency Control (LFC). The AGC principles are based on the fact that the quasi-steady state frequency is the same in the entire synchronous area; therefore, decentralized feedback implemented by each control area for responding to a local imbalance contributes to the overall balance in the system. The Area Control Error ACE is the sum of the weighted frequency deviation and the deviations of the net tie-line flow between the control area and its neighbors. The ACE is the control error for a PI controller with anti-windup. If the frequency bias factor B is chosen appropriately, a control area will only compensate for its imbalance, and it will neither counteract its frequency containment contribution nor its share of self-regulation; vice versa, AGC will compensate for a non-delivery of FCR in the respective area. This principle is referred to as non-interactive control [1], [2].

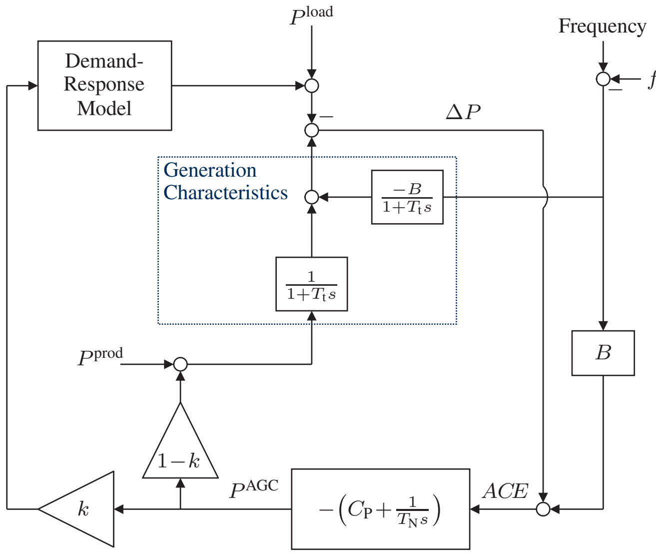


Fig. 1: Overview of the dynamic frequency model used for frequency restoration analysis.

Parameter	**Variable**	**Value**	**Unit**
Nominal frequency	f_N	50	Hz
Bias factor	B	350	$\frac{\text{MW}}{\text{Hz}}$
Generation time constant	T_t	4	s
AGC gain	C_p	0.17	–
AGC integration	T_N	120	s

TABLE I: Control structure parameters.

The control structure used in this paper is shown in Figure 1. The system in the model resembles the Swiss power system located in the middle of Continental Europe featuring 42 tie-lines. Since short-term phenomena, such as power plant dynamics and small-signal frequency swings, are not of importance for AGC, the modeled power system shares one common frequency and employs only first-order delays as conventional power plant models [16].

Disturbances in the system can be caused by an imbalance in either load (P^{load}) or production (P^{prod}). Load dynamics are not modeled: Typical values for the parametrization of dynamic loads are highly dependent on the structure of the load, vary over time, and the contribution made by dynamic load is small anyway. Furthermore, load dynamics help to stabilize the system in case of disturbances. Disregarding them helps focus on the main goal of this paper, namely investigating the impact of the rebound effect on frequency restoration. The AGC control signal P^{AGC} is sent to reserve providing units which deploy the respective amount of active power reserves, i.e. automatic FRR. The factor k describes which fraction is covered by the demand-response aggregation and which fraction by conventional active power reserve providers. The parameters used in the model are summarized in Table I.

B. Demand-Response Aggregation

A demand-response aggregator is a reserve providing group of thermostatically controlled loads. It modulates the consumption of individual loads such that the aggregated consumption follows the AGC activation. The aggregator groups its loads according to the baseline p (average consumption). The dimension of the baseline is chosen such that a typical AGC signal can be followed in an identical way for each load group. The aggregator can force load groups only to decrease, but not to increase consumption: It can only send off-signals because we use relays/disconnectors of the loads' power supply for the control instead of having access to the internal controller thermostat. To be able to provide not only upward but also downward regulation, the load groups are split into two pools. The control signal is tracked by dynamically sending activation signals to load groups in either the so-called available pool or the dark pool.

Load groups from the available pool are used for upward regulation of the total consumption and have a baseline consumption p. Upward regulation is done by sending off-signals to all devices inside a load group. To reduce the impact on the end-use performance of the loads, a maximum lifetime T is defined. This maximum lifetime describes the longest period for which a load group can be switched off. The maximum lifetime is based on the state of the thermostatically controlled load. When a switched-off load group reaches its maximum lifetime, it is released and replaced by a new load group. If a switched-off load group is released because of a change in the AGC, the demand-response aggregator releases the load group which has been switched off the longest. When a load group from the available pool is released from its switched-off state, either because it reached its maximum lifetime or because of a change in the AGC signal, it has a period of increased power consumption before returning to its baseline p. This is the rebound effect further described in Section II-C. When a load group returns to its baseline, it is again a load group in the available pool. This means that the number of load groups in the available pool is kept constant.

Load groups from the dark pool are used for downward regulation of the total consumption. These load groups have the same baseline p as load groups from the available pool, but are in a lower energy state. To push a load group into the dark pool, the loads inside a load group receive off-signals until the load group reaches the desired energy deficit. To keep a load group in the dark pool, the loads periodically receive off-signals so that the average consumption of the load group is p. When the loads inside a load group no longer receive off-signals, the load group has an increased consumption to compensate for the energy deficit. The downward regulation of the total consumption is done by way of this increased consumption. The time it takes for a load group to eliminate the energy deficit is again the maximum lifetime T. When a load group reaches its maximum lifetime, another load group from the dark pool starts to compensate for its energy deficit and a new load group is pushed into the dark pool. When a load group which is compensating its energy deficit is not needed anymore, it is pushed back into the dark pool and the loads within the load group receive off-signals to restore the energy deficit.

A similar effect to the rebound of load groups from the available pool is defined for load groups from the dark pool. After the period of increased consumption, the same load group or a new load group is pushed into the dark pool to keep the number of load groups in the dark pool constant. When a load group is pushed into the dark pool, it has a period of reduced consumption. This period of reduced consumption is defined as the rebound of load groups in the dark pool. The rebound characteristics for load groups from both pools are explained below.

C. Rebound Characteristics

The rebound of a load group from the dark pool is defined as the decrease in power consumption which pushes a load group into the dark pool. The process of putting a load into the dark pool is done by sending off-signals to devices within a load group. By controlling the frequency of these off-signals, we can spread the rebound over time. The rebound of a load group from the dark pool is defined as having the same shape as the rebound of a load group from the available pool, but it is less apparent because the process of putting a load into the dark pool is deliberately spread over time.

There are three important parameters that define a rebound: The maximum lifetime T, the reserve power of a load group p, and the recovered energy ratio Rec. The Rec of a load group in the available pool and the dark pool is defined in Equation 1 and Equation 2, respectively.

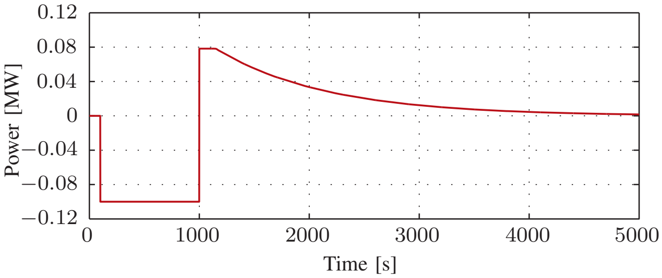
$$Rec_{\mathrm{a}} = \frac{\text{Recovered energy during rebound}}{\text{Lost energy during switched-off time}} \tag{1}$$

$$Rec_{\mathrm{d}} = \frac{\text{Lost energy during rebound}}{\text{Recovered energy deficit}} \tag{2}$$

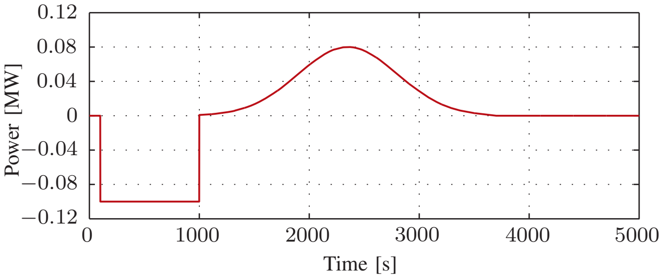
The rebound of a load group in the available pool can be shaped in various ways as summarized in Figure 2. Due to its similarity to a cold load pickup, an exponential decay rebound is an obvious choice (see Figure 2a). However, this rebound is considered worst case [17]. More common approaches are to rely on a normally distributed (see Figure 2b) and a lognormally distributed rebound (see Figure 2c). Both are based on practical experience gathered in demand-response management projects [15].

D. Model Parametrization and Case Studies

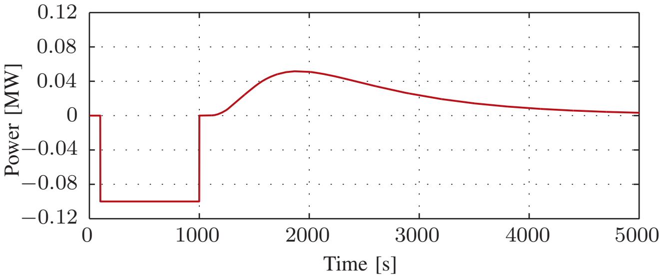
Four factors of the rebound effect shape the impact on the ACE: Rec, rebound type, k, and randomness. The factor k describes how much of the AGC signal is covered by the demand-response aggregator and the factor Rec denotes the recovered energy ratio. The randomness describes the maximum switched-off time periods of load groups. In case of a random, uniformly distributed number, the switched-off load groups show a high variety of maximum switch-off time periods implying a high randomness. To investigate these factors, two case studies have been defined:



(a) An exponential decay rebound.



(b) Normally distributed rebound.

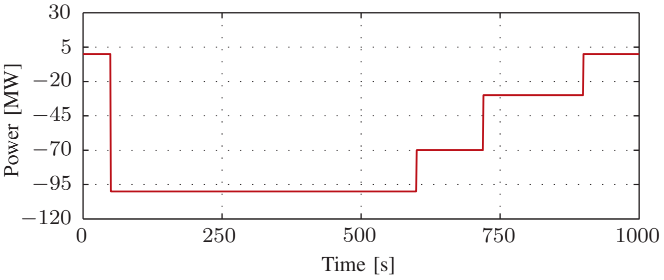


(c) A lognormally distributed rebound.

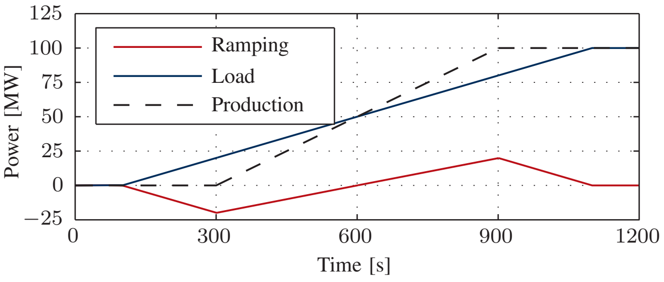
Fig. 2: Different rebound power characteristics of an activated load group from the available pool with $Rec = 1$, $T = 900\,\mathrm{s}$, and $p = 0.1\,\mathrm{MW}$.

- In the normal-case scenario, all three rebound types occur in the load groups and the maximum lifetime is random, uniformly distributed with $T \in [600\,\mathrm{s}, 2400\,\mathrm{s}]$. The rebound type of a load group is randomly chosen with the same probability for all three rebound types.
- In the worst-case scenario, the load groups all feature an exponential decay rebound with the same maximum lifetime of $T = 900\,\mathrm{s}$.

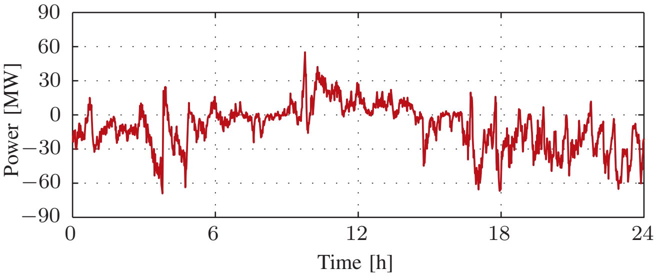
The two case studies are investigated using multiple simulations and varying k and Rec. The ranges are $k \in [0, 1]$ (no demand response, only demand response) and $Rec \in [0, 1.2]$ (no rebound, heavy rebound). To study the influence of the rebound effect on the ACE, the three case studies shown in Figure 3 are investigated. All three represent typical situations in daily operation. The first case study depicted in Figure 3a is a situation where active power reserves are triggered after an outage of a generating unit. The second case study illustrated in Figure 3b describes generation and load ramping in the mor-



(a) A forced outage; after 600 s manual reserves are deployed.

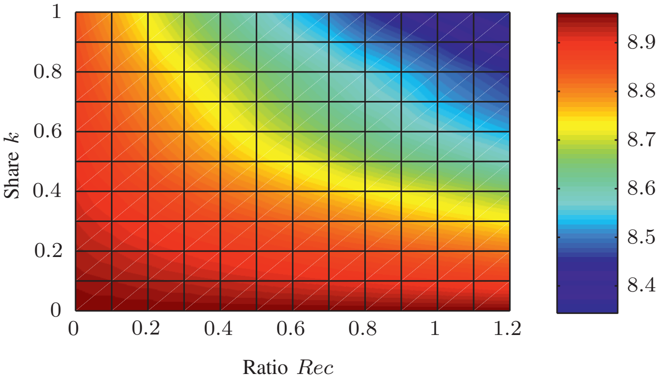


(b) Ramping as the difference between load and production.

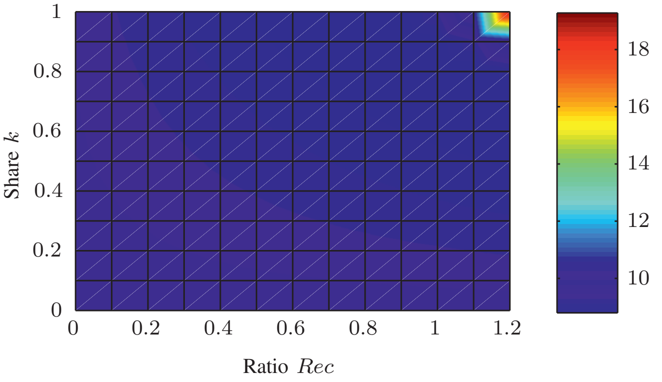


(c) Historical AGC activation over a typical working day.

Fig. 3: Different case studies.



(a) ACE RMS (normal-case scenario).



(b) ACE RMS (worst-case scenario).

Fig. 4: Summary of an RMS analysis for a forced unit outage.

ning and evening. In the third scenario shown in Figure 3c, the performance of the model is assessed using a historical AGC activation (real data from transmission system operation).

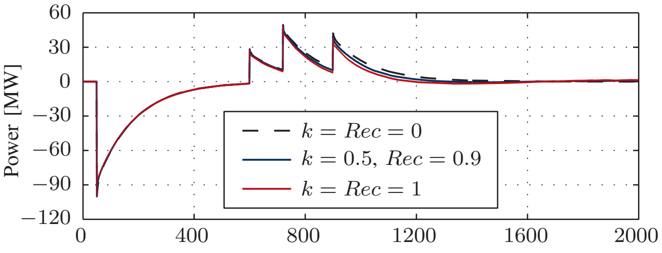
III. SIMULATIONS AND RESULTS

A. *Forced Unit Outage*

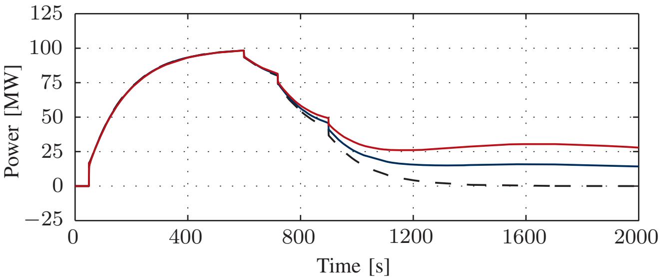
Figure 4 summarizes a sensitivity analysis by showing the Root Mean Square (RMS) of the ACE as a function of k and Rec. The RMS slightly decreases with increasing k and Rec in the normal-case scenario (see Figure 4a). The same effect occurs in the worst-case scenario, but not as clearly as in the normal-case scenario. The RMS increases sharply in the worst-case scenario with $k > 0.8$ and $Rec > 1$ (see Figure 4b).

The results in Figure 5 show that the rebound has no significant impact on the ACE: In Figure 5a, the ACE is shown for three normal-case scenarios. The plots show a typical PI controller response to a forced generator outage at $t = 50\,\mathrm{s}$. The ACE recovers almost to zero before the first block of manual reserves is deployed at $t = 600\,\mathrm{s}$. The activation of the second and third block of manual reserves is also clearly visible. Reserves provided by demand-response aggregation even have a small positive influence on the ACE. This effect is not obvious at first glance since an increase in the factors Rec and k leads to a higher rebound RMS. But it is exactly this rebound that helps to reduce the ACE, as the rebound starts to build up when the AGC activation decreases and the first load groups are released. This moment is at $t = 600\,\mathrm{s}$ when the first block of manual reserves is deployed. The sudden increase in generated power is partly consumed by the rebound. The same effect happens when a second and third block of manual reserves are connected. Therefore, the rebound helps to reduce the RMS in this scenario. This positive influence is independent of time and applies to manual reserve activations.

In worst-case scenarios with $k > 0.8$ and $Rec > 1$, rebound effects lead to severe instabilities. Figure 6 shows the ACE plot for a worst-case scenario with $k = 1$ and $Rec = 1.2$. With these parameters, the ACE starts oscillating and the oscillations are non-decreasing. The system becomes unstable, but the parameters which lead to this behavior are unlikely. A $k \geq 0.8$ means that at least $80\,\%$ of the automatic FRR are provided by demand-response aggregation. This is an unrealistically high number compared to the current almost negligible share: In Switzerland, less than $2\,\%$ of the reserves are provided by demand-response services [15]. Moreover, the Rec is highly dependent on the type of thermostatic control: For loads with



(a) *ACE* behavior.



(b) AGC activation (same legend as in Figure 5a).

Fig. 5: Forced unit outage in the normal-case scenario.

variable efficiency and complex local controllers, the Rec can be higher than 1. However, thermostatically controlled loads with constant efficiency and simple local controllers are rather common, i.e. $Rec < 1$.

The rebound has an increasingly adverse effect on frequency restoration in case of the higher k and Rec: There is a long-lasting AGC activation in case of large-scale demand-response aggregation. This lasting value increases the higher the rebound. It is the cause for the increase in the RMS observed for higher k and Rec. This means that not all switched-off load groups are released from their switched-off state. In other words, a certain amount of load groups must stay switched-off to compensate for the rebound. This is illustrated by a persisting AGC activation after the ACE is back to zero as illustrated in Figure 5b. This AGC activation slowly decreases and eventually reaches zero. The higher k and Rec are, the longer it takes for the AGC activation to return to zero, and if $k = Rec = 1$, the signal does not decrease to zero at all. For $Rec < 1$, the need to compensate for the rebound declines over time and the AGC activation decreases. The reason for this is that the number of new load groups which are switched off to compensate for the rebound is smaller than the number of load groups responsible for the rebound. The same effect is observed for $k < 1$, where a part of the rebound is always covered by reserves provided by generators without rebound. Therefore, the need to compensate decreases over time. For $k = Rec = 1$, the size of the rebound always stays the same and the lasting AGC signal remains. It is notable that the RMS of the difference between the AGC activation with and without demand-response aggregation, which is the rebound RMS, increases the higher k and Rec are.

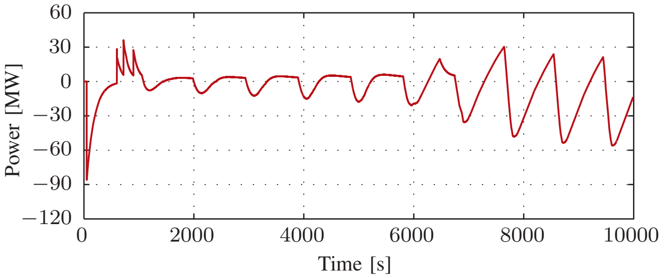


Fig. 6: ACE behavior after a unit outage in the worst-case scenario with $k = 1$ and $Rec = 1.2$.

B. Ramping

The ACE RMS of the normal-case scenario decreases with increasing k and Rec. In the worst-case scenario, the same effect can be observed, but with the difference that the ACE RMS significantly increases for $k > 0.8$ and $Rec > 1$. The rebound effect has a positive impact on the ACE RMS. The only exception where the rebound effect leads to an increase in the ACE is in the worst-case scenario with unlikely values of $k > 0.8$ and $Rec > 1$. However, even in this worst-case scenario, a severe instability was not observed. The positive impact can be explained by Figure 7: The rebound builds up in the first few minutes when the AGC signal decreases, but helps to reduce the ACE later (see Figure 7a). Obviously, the AGC signal is also positively influenced by the rebound (except at very high values of k and Rec). The reason for the rebound effect's positive impact on frequency restoration is the same as explained in Section III-A. After some time, the rebound reduces the need for AGC, as the lower AGC signal shows (see Figure 7b).

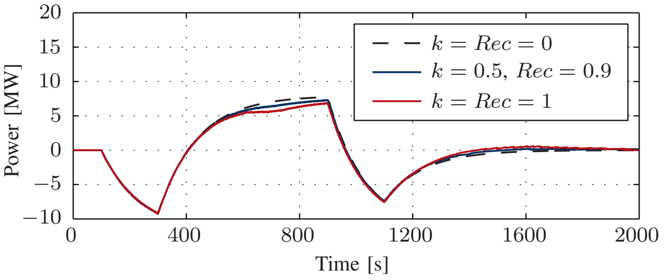
C. Historical AGC Activation

In the following, the response of a demand-response aggregator to a historical AGC signal, which forms the input for Figure 1, is analyzed. The rebound RMS increases with higher k and Rec. From the results of the forced outage study, we know the value of the rebound RMS (see Section III-A). The maximum AGC RMS deviation from the AGC signal without demand-response aggregation participation is 20 MW for unlikely values of $k = 1$ and $Rec = 1.2$. Figure 8 shows the difference between AGC activation and delivery in three normal-case scenarios: With an AGC signal of up to 70 MW (see Figure 3c), the rebound stays within ±15 MW (±30 MW) for $Rec = 0.9$ and $k = 0.5$ ($k = Rec = 1$).

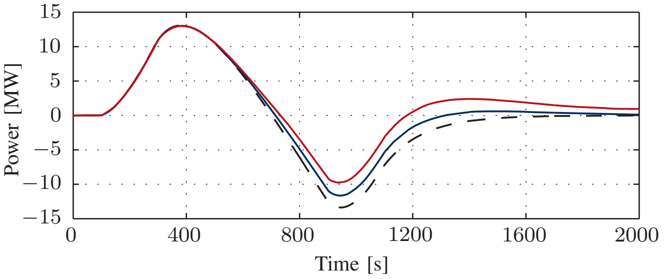
IV. CLOSING REMARKS

A. Conclusion

We analyzed the impact of rebound effects of demand-response services used for frequency restoration. The results of our studies showed that, in some circumstances, the rebound effect has a positive impact on the ACE. In an extreme case, rebound effects can lead to severe, non-decreasing power oscillations in the power system. However, the parameters



(a) *ACE* behavior.



(b) AGC activation (same legend as in Figure 7a).

Fig. 7: Ramping in three normal-case scenarios.

which lead to this worst-case situation are unrealistic in daily operation. In terms of AGC activation, the impact of the rebound effect is two-sided. In case of ramping, the rebound effect has a positive impact, whereas in case of a forced unit outage, it has a negative impact. In any case, demand-response aggregation with a rebound implies shifting consumption: Without additional energy-balancing actions, more AGC resources must be activated. As a result, demand-response management can be regarded as an energy shifter rather than a conventional reserve service altering the net energy level.

B. Outlook

Our investigations in this paper are based on current frequency control structures: The bulk of active power reserve providers are conventional power plants; they neither have significant rebound effects nor limited energy reservoirs. To gain more insights into future ancillary service provider setups, real-life data and load loss incidents need to be included. Furthermore, a long-term evaluation should analyze the behavior of the dark pool.

Nowadays, rebound characteristics usually are neither documented during pre-qualification, nor considered in real-time for AGC activation. Including individual characteristics of providers into the design and operation of control loops would allow making use of their positive effects and mitigate negative ones. Corresponding standard ancillary service products and payment in the form of performance-based remuneration for the reserve energy deployed could address these issues by providing a market-based solution.

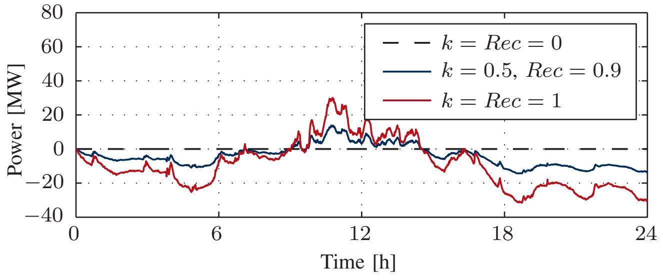


Fig. 8: Rebound in three normal-case scenarios over a typical working day.

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