Cost Allocation in Ancillary Service Markets

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***Abstract*—Market designs for reserve capacity in power systems face new challenges in terms of demand side participation (DSP) and renewable energy in-feed. In order to enhance power system flexibility and to reduce the amounts required of reserve capacity two key issues have to be tackled: First, financial incentives for DSP to participate in Ancillary Service markets. Second, incentives for intermittent sources and demand to adhere to their forecasted in-feed schedule. Therefore, we consider the public good aspect of reliable electricity supply and treat deviations from the schedule in in-feed or consumption as negative externalities in electricity market operation. Our contributions are twofold: First, we present a novel methodology which incorporates the individual evaluation of reserves via a suitable cost allocation framework and therefore enhances DSP to ensure operational security. Second, we provide a framework to establish market-based adaptive in-feed premiums for renewable energy sources and to assess investments in DSP and distributed storage in order to reduce the amount of reserve capacity procured by the System Operator. A simulation study shows that our approach leads to a Pareto-efficient reduction in the amount of procured reserves and hence social costs.**

***Index Terms*—Electricity Markets, Ancillary Service Market design, Pareto Efficiency, Public Good Economics.**

I. Introduction

Ancillary Service (AS) markets contribute via one-sided auctions for reserve capacity to the reliability of the system, essentially at whatever costs. AS-market designs gain importance for two reasons: First, fluctuating energy in-feed in large scale will increase balancing requirements [1], [2]. Second, fluctuating energy in-feed in remote areas, in addition to market-based energy flows, may increase the occurrence of contingency conditions.

The definitions of ancillary service products differ across AS-markets (see also [3] and [4]). Throughout the paper, we use the terminology of non-event driven and event-driven reserve capacity. Non-event driven reserve capacity, i.e. regulating reserves and ramping services, ensures frequency containment in normal operation. Event-driven reserve capacity, i.e. contingency reserves, compensates power plant outages or line outages and contribute to frequency restoration in case of major disruptions.

However, even though the requirements on event and non-event driven reserves will increase, the costs of procured reserves and renewable energy in-feed are allocated merely on administrative rules, i.e. system-wide socialization. This decreases financial incentives for demand response programs and market-based integration of renewable energy in-feed. Economic theory suggests to price contingency services like reliable electricity supply based on the individual valuation of it. Further, the allocation of costs of procured non-event driven services is in general not based on costs-by-cause principles. Currently some market participants have few or no obligations to satisfy an announced schedule. Costs of holding reserve capacity caused by these market participants due to balancing requirements are then socialized.

The main objective of this paper is to propose an AS-market framework which comprises:

1) A market-based allocation of the procurement costs for event-driven reserves. For this purpose, we assume the existence of an elastic demand curves for event-driven reserves (see also [5] and [6]) and the incorporation of locational prices (see also [7]). The elasticity of demand for reserve capacity represents an individual valuation of reliable electricity supply. The auction design for event-driven reserves requires a special economic methodology since reliability in power systems can be seen as a kind of public good with aspects of non-rivalry and non-excludeability (see also [8]).
2) An efficient procurement and cost allocation of non-event driven reserves via the assessment of the systemwide costs that are incured by holding reserves versus the costs of avoiding reserve requirements. This approach is similar to the economic theory of pricing the economic activity of one market participant who negatively influences the economic goals of another one and therefore distorts the market outcome (see also [9]). We assume that distorting market participants are primarily characterized by fluctuating in-feed or demand.

According to the rules by European Network of Transmission System Operators for Electricity (ENTSO-E), the demand for non-event driven and event driven reserves depends on the forecasted load level or the largest blocks in operation in the control areas [10]. Some European system operators also consider load uncertainty and renewable in-feed deviations via fixed quantiles from an empiric distribution function derived from historic forecast errors for non-event reserve capacity determination [11]. However, the reserve demand determined is inelastic, and the procurement costs do not refer to the individual valuation of it, or to the degree of utilization of the

978-1-4799-2504-9/14 $31.00 © 2014 IEEE
DOI 10.1109/HICSS.2014.289

grid. For example, ref. [12], [13], [14] determine an elastic demand for spinning reserves via a cost/benefit analysis. All approaches did no analysis about the proper cost allocation of procured reserve capacity Ref. [15] and [16] address the allocation of costs for procured event and non-event driven reserves. The established metric for cost assignment is based on the analysis of historic data. Ref. [17] determines the system costs of adding wind generation whereby the results show that the benefits are highly sensitive to how much of the inherent variability of wind generation is mitigated.

Our contributions are twofold: First, we provide a methodology to procure event-driven reserves and allocate the costs according to the individual valuation of it. The market framework may serve as a basis for further development of financial incentives and contract designs. Second, we provide a methodology to allocate the costs of non-event driven reserve capacity. This approach also enhances the development of respective DSP programs and the market-based implementation of renewable energy in-feed. We assess in a simulation study our market framework in terms of the procured amounts of reserves, costs imposed on market participants and the effect of strategic behavior of generators.

The structure of the paper is as follows: In Section II, we highlight the model which comprises the clearing for event-driven reserves and non-event driven reserves. In Section III we highlight special issues with regards to the implementation of the model. In Section IV we present the simulation framework. In Section V we proceed with results of a simulation study. In Section VI we conclude and give a future outlook.

II. Market-Based Procurement and Cost Allocation of Reserve Capacity

Fig. (1) shows the setup of the proposed framework. Similar to [12], we proceed first with a unit commitment with flexible demand and without reserve power considerations. Through the unit commitment we achieve the locational marginal prices or energy traded and are able to calculate the lost opportunity costs of reserve provision in the course of the co-optimization. Subsequent, a co-optimization of energy and reserve capacity is done. The rewards may be further used as a feedback to simulate strategic behavior of market participants.

A. Unit Commitment with Elastic Demand

We model DSP of consumer j and time instant t, by using a constant elasticity of demand function with of the form,

$$Q^{j,t} = A^{j,t}(p^{j,t})^{\epsilon^{j,t}}, \tag{1}$$

where $Q^{j,t}$ is the procured quantity, $A^{j,t}$ represents an operating point, $p^{j,t}$ is the price of electricity and $\epsilon^{j,t}$ is the elasticity of demand, which is defined by:

$$\epsilon = \frac{dQ^{j,t}}{dp^{j,t}} \frac{p^{j,t}}{Q^{j,t}}. \tag{2}$$

We solve the fitting problem for a piecewise linear representation of a nonlinear data curve with a variable partition space by applying an approach proposed by [18]. The energy market is

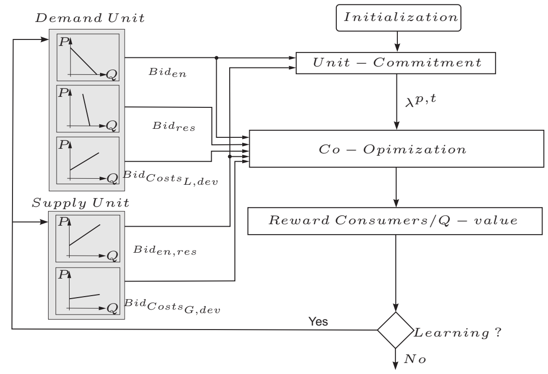


Fig. 1: Proposed framework: Demand units have beside their energy bids (Bid_{en}) also the opportunity to bid a demand for reliable electricity supply (Bid_{res}). Further, they announce their costs of reducing non-event based imbalances ($Bid_{Costs_{L,dev}}$). Conventional generation units bid energy and reserve capacity ($Bid_{en,res}$). Intermittent energy sources announce their costs of keeping the forecasted schedule ($Bid_{Costs_{G,dev}}$). The unit commitment gives nodal prices $\lambda^{p,t}$ to assess the lost opportunity costs of reserve provision in the co-optimization.

modeled by a unit-commitment problem with piecewise-linear offer-curves from the generators (see also [19] and [20]):

$$\begin{aligned} \max. \sum_{t=1}^{T} \Bigg\{ &- \sum_{i=1}^{N_G} (u^{i,t} C^{i,t}_{noload} + C^{i,t}_{Start}) + \\ \sum_{j=1}^{N_L} \sum_{k=1}^{K} MB^{j,k,t}_{En,seg} P^{j,k,t}_{En,seg} &- \sum_{i=1}^{N_G} \sum_{s=1}^{S} MC^{i,s,t}_{En,seg} P^{i,s,t}_{En,seg}) \Bigg\} \end{aligned} \tag{3}$$

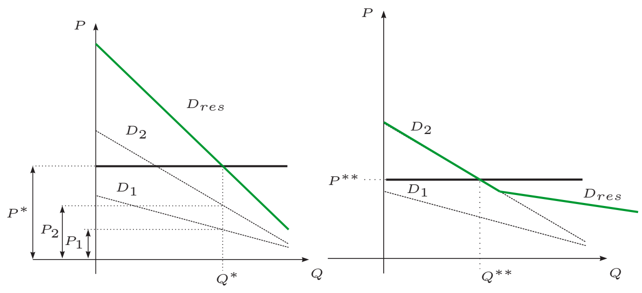
subject to

$$\begin{aligned} \boldsymbol{g(x,u)} &= \boldsymbol{0}, \\ \boldsymbol{h(x,u)} &\leq \boldsymbol{0}, \end{aligned} \tag{4}$$

where i,s,t denotes segment s of generator i at time t, and j,k,t denotes segment k of load j at time t. C^{i}_{noload} are the costs of insufficient loading of a power plant and $C^{i,t}_{Start}$ are the start-up costs. $P^{j,k,t}_{En,seg}$ and $P^{i,s,t}_{En,seg}$ are the demand and generation in line segment k and s respectively. $MB^{j,k,t}_{En,seg}$ and $MC^{i,s,t}_{En,seg}$ are the segment-wise marginal benefit/cost of consuming/producing electric energy at the line segment respectively. $\boldsymbol{g(x,u)}$ and $\boldsymbol{h(x,u)}$ are constraints, which are necessary to fulfill energy balance, start-up and shut-down times of generators, ramping limits of generators, and limits in terms of generation and demand capacity. $\boldsymbol{x}$ and $\boldsymbol{u}$ denote additional continuous and binary variables.

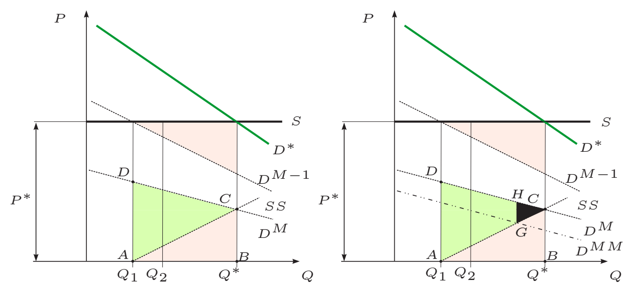
B. Event-driven Reserve Demand and Cost Allocation

1) Elastic Event-driven Reserve Demand: The individual demand for event-based reserves is decoupled from the amount of energy consumed (see also [21]). Elastic demand curves for non-event driven reserves have also already been derived by [12], [13], [14] and [22]. For example, Ref. [12] established a demand curve for spinning reserves via the concept of Expected Energy not Served (EENS) and a constant Value of Lost Load (VOLL). The EENS results from the generation schedule with the corresponding Capacity Outage Probability



(a) (b)

Fig. 2: Market clearing for public and private goods and constant marginal costs of supply: (a) Public good clearing: The demand curves D_1 and D_2 are added vertically (D^*_{res}) to achieve a Lindahl equlibrium (P^*,Q^*). The individual cost shares are P_1 and P_2, (b) Private Good Market Clearing: The demand curves D_1 and D_2 are added horizontally (D^{**}_{res}) to achieve an equilibrium (P^{**},Q^{**}).



(a) (b)

Fig. 3: Preference revelation via Clarke-Groves-Mechanism: (a) Starting from the case of no preference for the public good Q_1, the individual consumer has to pay the marginal compensation of $\int_{Q1}^{Q^*} SS = ABC$ for the provision of the public good. The welfare is marked by ACD. (b) In case of mispresentation of preferences the consumer looses welfare of GCH.

Table (COPT) [23]. Ref. [13] established an elastic demand curve by taking into account the probabilistic nature of contingencies and their impact with regards to different cost factors, i.e. costs of frequency deviations, costs associated to automatic load shedding and the costs associated with deviations over the scheduled power exchange.

For the application in our approach, the analysis done in these works has to be adapted to represent locational demand (node or area-wise) for event-driven reserves based on the generation schedule achieved from the unit commitment problem, which is out of the scope of this paper and part of future research. Instead, we assume that the demand functions are similar to equation (1). The operating points and the elasticities of the demand curves are subject to the effort of the system operator or utility to arrange interruptible load contracts (see also [24]), the flexibility of industrial processes etc..

2) Cost Allocation of Procured Reserves: We aggregate the individual demand curves for reserves as shown in Fig. (2a), which differs from the known market aggregated demand (Fig. (2b)) for private goods like energy. The established market clearing for event-based reserves is called *Lindahl equilibrium*, contains a Pareto efficient cost allocation in case of linear costs for procured ancillary services, and has a Nash-equlibrium (see also [8] and [25]). The Lindahl equilibrium is used to establish prices for the generation units. However, there exist incentives for a mispresentation of event-driven reserve requirements by the demand side in order save costs. This gaming behavior may lead to operational security problem, as insufficient reserves are procured. Therefore, we propose a separate market clearing mechanism for the demand side based on the Clarke-Groves mechanism [26], which is illustrated in Fig. (3a) and (3b): Assume the demand curves for event-driven reserves of M individuals are aggregated to D^*. The demand curve D^{M-1} represents the sum of demand curves excluding individual M with demand D^M. If individual M has no preferences for reserve capacity he would have to pay no price and stays at point A. If the individual demands a certain amount of reserve capacity, e.g. $Q1Q2$, then he has to pay a marginal compensation of $\int_{Q1}^{Q2} SS$ for the additional costs he causes to the other individuals. The largest possible surplus for the individual comprises the area ACD. In Fig. (3b) it is shown that the individual loses the surplus GCH in case of stating a too low demand for event-driven reserves, D^{MM}. In total we solve $M+1$ optimization problems in order to establish market clearing prices for the generators to engage loads to reveal their reliability preferences truthfully.

The mechanism guarantees an efficient allocation according to the Samuelson rule [27], but no overall efficient allocation. Demand units may pay more for procured reserves than necessary. This excess has to be redistributed again, which probably lowers the efficiency of the algorithm in terms of preference revelation. An appropriate redistribution algorithm is beyond the scope of this paper. However, this approach may serve as a market-based alternative compared with cost socialization.

C. Non-event Reserve Requirements and Cost Allocation

1) Chance Constrained Determination of Non-event Reserve Requirements: The sources of non-event driven reserve requirements are fluctuating energy in-feed (W) and demand units (L). Therefore, the total production/demand $P^{L,W}_{total}$ can be decomposed into,

$$P^{L,W,t}_{total} = P^{L,W,t}_{f} + \tilde{P}^{L,W,t} \tag{5}$$

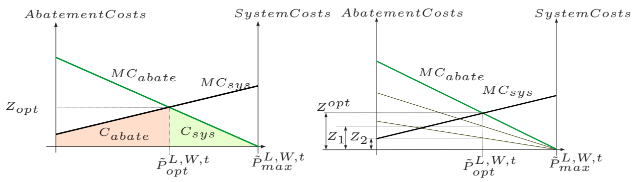
where $P^{L,W,t}_{f}$ is the hourly forecasted production and $\tilde{P}^{L,W,t}$ is a random deviation from it, which varies between zero and $\tilde{P}^{L,W,t}_{max}$ depending on the effort of the producer W or consumer L to reduce fluctuations at time t. We use chance-constraints to determine probabilistic up and down reserve power levels $\tilde{R}^{Up,t}_{req}$ and $\tilde{R}^{Dn,t}_{req}$, which guarantee the netting of the negative imbalances ($x^t_{neg} \doteq \tilde{P}^{L,W,t} < 0$) and positive imbalances ($x^t_{pos} \doteq \tilde{P}^{L,W,t} > 0$) of wind in-feed and demand at every time instant t with a probability $1-\gamma$:

$$\mathbb{P}(x^t_{neg} \leq \tilde{R}^{Up,t}_{req}) \geq (1-\gamma), \tag{6}$$

$$\mathbb{P}(x^t_{pos} \leq \tilde{R}^{Dn,t}_{req}) \geq (1-\gamma),. \tag{7}$$

Further, we assume a symmetric band for up and down non-event reserve capacity $\tilde{R}^t_{req}$, which is determined by

$$\tilde{R}^{t}_{req} = [\tilde{R}^{Up}_{req,t}, \tilde{R}^{Dn}_{req,t}]^{+}. \tag{8}$$



(a) (b)

Fig. 4: Cost allocation for non-event driven reserves: (a) In case of an equilibrium point ($Z_{opt}, \tilde{P}_{opt}^{L,W,t}$) and competitive market conditions, the total cost $TC = C_{abate} + C_{sys}$ is a minimum. In case of competitive markets, the producer will reveal his true marginal costs. (b) In case several producers of externalities (wind in-feed and demand) which influence the amount of non-event driven reserves, Z^{opt} is shared according to the stated marginal abatement curves (Z_1 and Z_2). Therefore preference revelation incentives will be necessary.

2) Cost Allocation: The output of fluctuating power can be reduced to a social optimal outcome if the marginal costs of avoiding imbalances are equal to the marginal system costs of balancing them (Fig. (4a), see also [9]). The system costs, C_{sys} of non-event based reserve capacity, are the costs of reserves procured by the system operator. These costs are in contrast to the costs that a fluctuating in-feed facility/demand unit has, C_{abate}, if they would try to abate random deviations from the schedule. In equilibrium the sum of these costs,

$$TC = C_{abate} + C_{sys}, \tag{9}$$

is minimized. The "clearing price", Z^{opt}, may be interpreted as a tax on fluctuating in-feed/demand. We assume that the marginal costs for avoiding imbalances from the schedule are of the form:

$$MC_{abate}^{w/d,t} = \left(\frac{P_{abate}^{w/d,t}}{B^{w/d,t}}\right)^{\frac{1}{\eta^{w/d,t}}}, \tag{10}$$

where $B^{w/d,t}$ is a positive factor and $\eta^{w/d,t}$ is the elasticity of supply for abating deviations and $P_{abate}^{w/d,t}$ is the abated amount of fluctuating in-feed source w, and demand unit d at time instant t.

Clearly, only the resulting fluctuations of several injections are relevant for the deployment of reserve energy. We therefore propose as shown in Fig. (4b) an extension to the concept presented in Fig. (4a). Similar to the concept of the Lindahl equilibrium, this framework requires truthful revelation of the abatement costs. In case of renewable energy in-feed, the cost share resulting from the proposed cost allocation mechanism may be used to transform in-feed tariffs into in-feed premiums. These premiums give renewable energy-in feed units the incentive to invest in measures which reduce deviations from the schedule. In case of demand units, the cost share may be used to adapt grid tariffs and to establish financial incentives for demand side participation.

Finally, the proposed framework may not only be valid for e.g. regulation reserves, but can be expanded for the determination of the social optimal ramping of demand and renewable in-feed, which is part of future research.

D. Energy and Reserve Co-Optimization

Co-optimization is proven to be the most efficient form of energy and reserve power scheduling (see also [28], [29]). The objective function includes start-up and no-loading costs of a power plant, the market clearing for energy, event-driven up and down reserves, the minimization of Lost Opportunity Costs of the generators, the minimization of procurement costs of non-event driven reserves and the minimization of the costs to abate fluctuations.

$$\begin{aligned}
&\max . \sum_{t=1}^{T} \Bigg\{ -\sum_{i=1}^{N_G} (u^{i,t} C_{noload}^{i} + C_{Start}^{i,t}) \\
&\sum_{j=1}^{N_L}\sum_{k=1}^{K} MB_{En,seg}^{j,k,t} P_{En,seg}^{L,j,k,t} - \sum_{i=1}^{N_G}\sum_{s=1}^{S} MC_{En,seg}^{i,s,t} P_{En,seg}^{i,s,t} + \\
&\sum_{z=1}^{Z} MB_{evt_{up,seg}}^{z,t} P_{evt_{up,seg}}^{z,t} - \sum_{i=1}^{N_G}\sum_{s=1}^{S} MC_{evt_{up,seg}}^{i,s,t} P_{evt_{up,seg}}^{i,s,t} - \\
&\sum_{y=1}^{Y} MB_{evt_{dn,seg}}^{y,t} P_{evt_{dn,seg}}^{w,t} - \sum_{i=1}^{N_G}\sum_{s=1}^{S} MC_{evt_{dn,seg}}^{i,s,t} P_{evt_{dn,seg}}^{i,s,t} - \\
&\sum_{i=1}^{N_G} LOC_{evt,up,}^{i,t} - \sum_{i=1}^{N_G} LOC_{noevt,up}^{i,t} - \\
&\sum_{i=1}^{N_G}\sum_{s=1}^{S} MC_{noevt_{up,seg}}^{i,s,t} P_{noevt_{up,seg}}^{i,s,t} - \\
&\sum_{i=1}^{N_G}\sum_{s=1}^{S} MC_{noevt_{dn,seg}}^{i,s,t} P_{noevt_{dn,seg}}^{i,s,t} - \\
&\sum_{w=1}^{N_W}\sum_{q=1}^{Q} MC_{abate_{seg}}^{w,q,t} P_{abate_{seg}}^{w,q,t} - \sum_{d=1}^{N_D}\sum_{r=1}^{R} MC_{abate_{seg}}^{d,r,t} P_{abate_{seg}}^{d,r,t} \Bigg\}
\end{aligned} \tag{11}$$

subject to

$$\begin{aligned}
\boldsymbol{g}(\boldsymbol{x},\boldsymbol{u}) &= \boldsymbol{0}, \\
\boldsymbol{h}(\boldsymbol{x},\boldsymbol{u}) &\leq \boldsymbol{0},
\end{aligned} \tag{12}$$

where i,s,t denotes segment s of generator i at time t, and j,k,t denotes segment k of load j at time t. $MB_{En,seg}^{j,k,t}$, $MB_{(non)evt_{up/dn,seg}}^{z,t}$ are the marginal benefit function for energy and (non-)event driven up/down-reserves. $MC_{En,seg}^{i,s,t}$, $MC_{(non)evt_{up/dn,seg}}^{i,s,t}$ are the marginal costs of providing energy and (non-)event driven up/down-reserves respectively. $LOC_{evt,up,}^{i,t}$ and $LOC_{nonevt,up,}^{i,t}$ are the lost opportunity costs of generators in case of provision of event-driven or non-event driven reserve capacity. $MC_{abate}^{L,j,r,t}$ are the marginal costs of avoiding non-event driven imbalances. z, w, r and q refer to the segments of the respective cost/benefit function. $P_{En,seg}^{i,s,t}$, $P_{evt_{up,seg}}^{z,t}$, $P_{evt_{dn,seg}}^{y,t}$ and $P_{abate,seg}^{w/d,q/r,t}$ state the energy production of generators, demand for event-driven up and down reserves, and the avoided amounts of fluctuating consumption/in-feed by the respective producers or load serving entities. The constraints $\boldsymbol{g}(\boldsymbol{x},\boldsymbol{u})$ and $\boldsymbol{h}(\boldsymbol{x},\boldsymbol{u})$ represent energy balance, start-up and shut down times, ramping limits of generators and capacity limits of generators and demand. $\boldsymbol{x}$ and $\boldsymbol{u}$ denote additional continuous and binary variables. A complete formulation of the constraints and the nomenclature is given in the appendix. The shown formulation has to

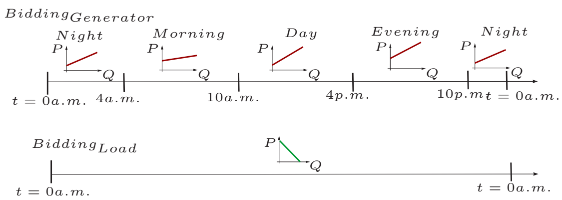


Fig. 5: Bidding Setup for Loads and Generators for a 24h Period. The intercept and slopes are only schematic and point out the varying elasticity of demand over the time horizon. The considered time periods τ are $Night$, $Morning$, Day, $Evening$.

be adapted for the Groves-Clarke mechanism accordingly. For non-event driven reserves we assume that the marginal costs for reducing deviations from the schedule are revealed truthfully.

III. Implementation of Strategic Behavior and Chance-Constrained Optimization

A. Strategic Behavior of Market Participants

The last part of the assessment is done with regards to the influence of strategic behavior by the market participants. The generation units aim to maximize profits and may exploit market power either through low liquidity in the auction for reserves or through highly loaded and congested networks via a markup on the stated marginal cost curves. We incorporate these behavior in the model via an approximate dynamic programming approach: Q-learning. The Q-learning algorithm is a mapping of the reward/cost gained from a specific action and is used in a proper exploration/exploitation strategy to minimize reward of an action through a learning process. The rule for the update process of the Q-value is [30], [31]:

$$Q_a^\tau(k+1) - Q_a^\tau(k) = \alpha(r_a^\tau(k+1) - Q_a^\tau(k)), \tag{13}$$

where a refers to the action chosen, r_a^τ to the resulting cost/reward and k to the learning round per time period τ. The considered time periods are shown in Fig. (5).. As a variant of this approach we use continuous Q-learning [32] and implement a separate learning sequence for every decision variable. Generators influence the markup on the marginal cost bids for energy, event-driven and non-event driven reserves.

B. Solving Chance Constraints

The chance constraints are implemented with the scenario approach of [33] using the Markov-Chain-Monte-Carlo scenario generation of [34]. The main idea of [33] is to consider only a finite number of instances (scenarios) of the uncertain parameter, and then solve a corresponding linear program. Ref. [33] provides a lower bound for the number of scenarios that should be extracted to provide the desired probabilistic guarantees with high confidence. Following [35] the number of samples that one needs to generate is $N_s \geq \frac{2}{\epsilon}\big(N_d + \log\frac{1}{\beta} + 1\big)$, where $\epsilon \in (0,1)$ is a violation parameter, $\beta \in (0,1)$ is a confidence level, and N_d is the number of decision variables. By generating then N_s samples, the solution of the corresponding problem will violate the chance constraint with probability at most ϵ, with confidence at least $1-\beta$. The considered approach assumes as an approximation that the considered time periods do not have correlation in the uncertainty.

IV. Test System and Simulation Framework

A. Test-System

In the simulation study we compare three different *market designs*:

1) M_{A1}: The market clearing for event-based reserves is done via an elastic demand curve. The demand of non-event based reserves is inelastic and fixed, but the determination is done via chance-constrained optimization.
2) M_{A2}: The market clearing for event-based reserves is done via an elastic demand curve. The market clearing for non-event based reserves is done based on the cost comparison proposed in Section II-C2.
3) M_B: The scheduled amount of reserves is based on functions similar to current market operations. The amount of non-event reserve demand is based on the ENTSOE-Formular [10]:

$$P_{nonev} = \sqrt{a \cdot P_{max}^{en} + b^2} - b, \tag{14}$$

whereby $a = 10$ are $b = 150$ predefined parameters and P_{max}^{en} is the scheduled peak demand. Additionally, we assumed that 20% of the hourly wind forecast are hedged by non-event driven reserves. The amount of event-driven reserves is based on the largest unit online at a certain time instant.

We modified the IEEE-RTS Test system [36], [37]. For computational reasons, we aggregated similar generators at the same node and the same cost characteristic. For the simulation study we used two *system settings*:

- Sim_{strat}: We assume no grid and a small number of demand units. The generation units may act strategically. In case of strategic behavior, the node-wise grouped generators further aggregated in terms of the technical/economic characteristics to reduce the computational effort. The total number of strategically acting generators is seven. The time horizon for the simulations is 24 hours.
- $Sim_{nostrat}$: We incorporate a grid and assume no separate loads at the busses 2, 3, 4, 5 and 16. However, the demand of these loads is distributed over the other busses. Due to computational effort we reduced the time horizon to 18 hours. We added a wind-powered generation unit at bus 16.

The model data for the elasticity of demand for energy and reliability are shown in the appendix as well as the assumed possible changes for the elasticity of supply through strategic behavior of the generators. Fig. (6) shows the considered aggregated load profile and wind-infeed scenario. In case of simulation framework Sim_1 we assumed the in-feed scenario $Wind_1$. In case of simulation framework Sim_2 we assumed the in-feed scenario $Wind_2$. Uncertainty in demand is modeled via a zero-mean gaussian distribution function and standard deviation of 2% of the hourly load. We used real-world data for the short-term uncertainty of wind-energy infeed.

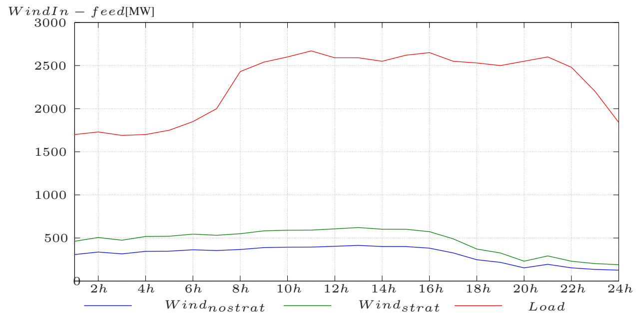


Fig. 6: Considered wind scenarios and load profile. Due to computational issues we assumed different wind scenarios. $Wind_{strat/nostrat}$ refers to the assumed wind scenario in the system framework $Sim_{strat/nostrat}$.

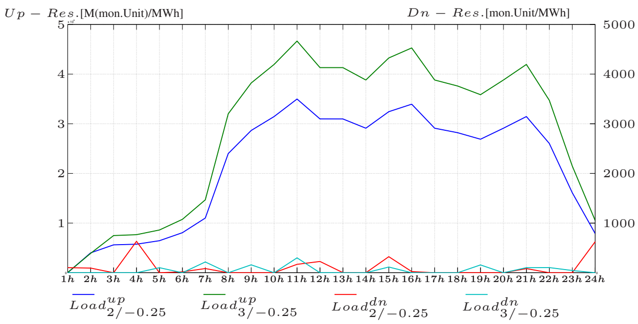


Fig. 7: Payments by the demand side due to the Groves-Clarke mechanism in case of low elasticity of demand for event-driven reserves. $Load^{up}_{2/-0.25}$ refers to the payment in case of 2 loads and an assumed elasticity of demand for non-event up-reserves of -0.25 (other variables correspond respectively). The payments decrease with the number of participants. Payments for up-reserves are substantially higher than for down reserves.

V. Simulation Results

A. Groves-Clarke Tax for Valuing the Demand of Reliability

We assume market design M_{A2} and the simulation model Sim_{strat}. Generators do not act strategically and we share the total demand equally between two and three demand units. Further, we assume different elasticities of demand for event-based reserve capacity. Fig. (7) and (8) show the payments based on the proposed Groves-Clarke mechanism in case of two and three demand units respectively. Clearly the individual's cost share decreases with the number of market participants. This also indicates to a known problem of the mechanism with regards incentive compatibility in case of a large number of consumers. However, the payments may also only attribute to aggregated load serving entities. Fig. (8) highlights the impact of increased elasticity of demand for event-driven reserves. Further, in case of down-reserves the payments mainly occurs at times of low demand.

B. Price and Quantity Impact of Proposed Frameworks in Competitive Market Environment

1) Effect of Elasticity of Event-based Reserve Demand Curve: In this simulation study we assess the market designs M_{A1} and M_{A2} and assume the simulation framework $Sim_{nostrat}$. Fig. (9) shows the averaged market clearing prices

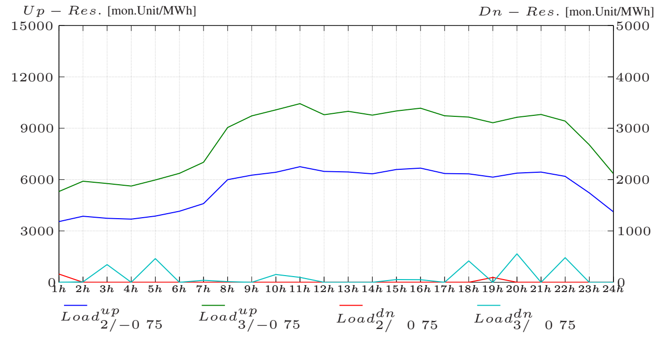


Fig. 8: Payments by the demand side due to the Groves-Clarke mechanism in case of high elasticity of demand for event-driven reserves. $Load^{up}_{2/-0.75}$ refers to the payment in case of 2 loads and an assumed elasticity of demand for non-event up-reserves of -0.75 (other variables correspond respectively). The payments decrease with the number of participants. Payments for up-reserves are substantially higher than for down reserves.

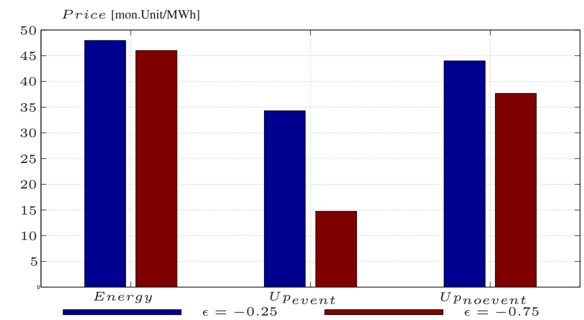


Fig. 9: Average prices [mon.Unit/MWh] for energy ($Energy$), event-driven up-reserves (Up_{event}) and non-event driven up-reserves ($Up_{noevent}$) assuming market design M_{A1} and system setup $Sim_{nostrat}$. Higher elasticity of demand leads to a price reduction for all products.

for energy, event driven up reserves and non-event driven up-reserves in case of M_{A1}. A higher elasticity of demand for event-driven reserves reduces significantly the price for it and hence also for energy and non-event driven reserves through higher spare capacity.

Fig. (10) and (11) compare the market designs $Design\ A1$ and $Design\ A2$ in terms of procured amounts of event-based and non-event driven reserves also in case of higher and lower elasticity of demand for event-based reserves. Due to the assumed data for demand and supply, the procured amounts of non-event-based reserves is higher in both market design. This may change likely assuming a low valuation of event-driven reserves, which is justified through it's very low probabilities of occurrence and the inability of the customer to deal with rare events. However, we find that if fluctuating in-feed or demand units have higher balance responsibility as in M_{A2}, the amount of procured non-event based reserves decreases.

2) Effect of Elasticity of Supply Curve to avoid Imbalances: We assess different elasticities in the supply of deviation abatement by fixing the demand curve for event-based reserves. We change the elasticities for loads or wind in-feed separately. As shown in Fig. (12), we find in our simulation study that investments or adaptive in-feed premiums which enhance balancing effort for renewable in-feed have a higher impact than similar measures on the demand side. For a

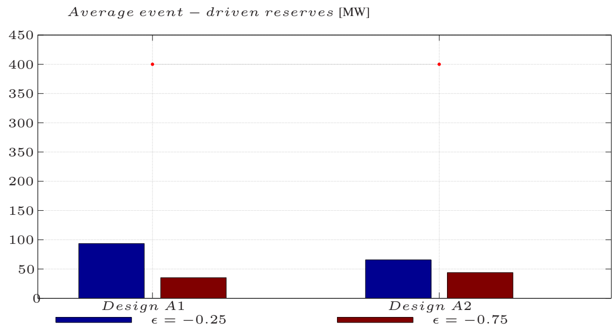


Fig. 10: Average scheduled amounts of event-driven up-reserves in case of M_{A1} and M_{A2} and system setup $Sim_{nostrat}$. Red dots refer to amount of reserves scheduled with regards to M_B.

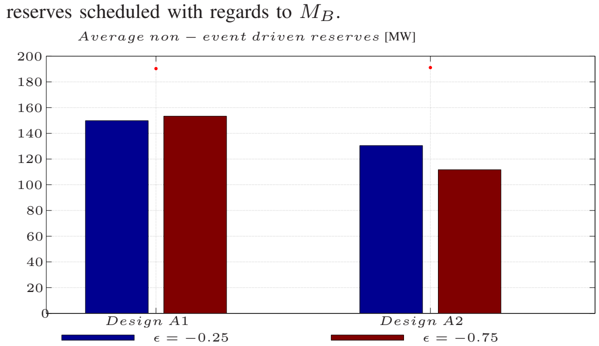


Fig. 11: Average scheduled amounts of non-event driven up-reserves in case of M_{A1} and M_{A2} and system setup $Sim_{nostrat}$. Red dots refer to amount of reserves scheduled with regards to M_B.

comprehensive analysis the specific abatement cost curves have to be known.

C. Social Welfare Impact of the Proposed Framework in Presence of Strategic Behavior of Generators

In this part of the study we assumed that the system is aggregated to one load and there exist no grid constraints. We test the effectiveness of demand side elasticity for event-driven reserves in terms of average bidding markup for reserve capacity (including event-driven and non-event driven reserves). The results in Fig. (13) show that (a) the bidding markup is generally higher in times of low demand, (b) the markup decreased with the introduction of elastic event-driven demand and (c) the markup may further decreases through the introduction of a Pareto-efficient clearing for non-event reserve capacity.

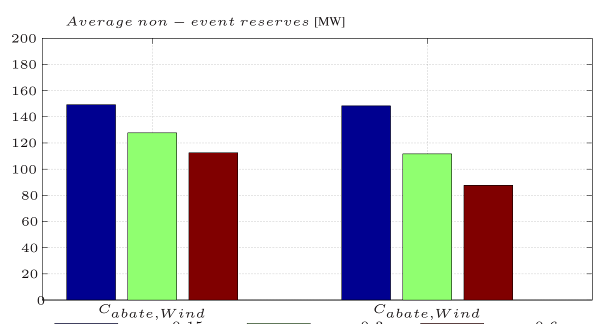


Fig. 12: Average scheduled amounts of non-event driven up-reserves ($Up_{noevent}$) in case of M_{A2} and system setup $Sim_{nostrat}$. Higher abatement costs for wind $C_{abate,Wind}$ and load $C_{abate,Load}$ lead to a higher procurement of reserves in order to ensure Pareto-efficiency in the cost allocation.

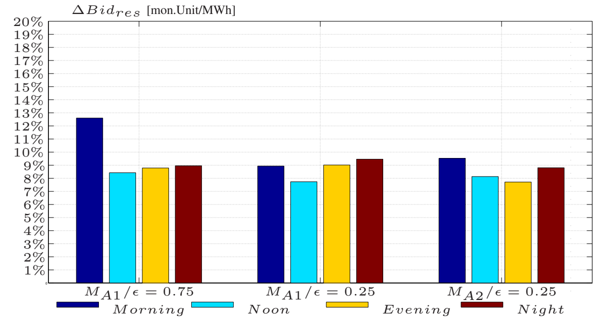


Fig. 13: Bidding Markup for reserves capacity (ΔBid_{res}) considering M_{A1} and M_{A2} and different elasticities of demand for event-driven reserves.

VI. Conclusion and Future Work

In this paper we have presented a methodology to integrate renewable energy in-feed and DSP on market-based principles. We have shown that one of the key factors is the cost allocation of event-driven and non-event driven reserves based on economic principles, either through the consideration of the value of reliable of electricity supply for the customer, or via the cost allocation based on cost-by-cause principles.

First, we find that the introduction of elastic demand for event-based reserves can reduce market power and leads to an amount of procured reserves which is economically efficient. Costs incured on consumers are efficiently distributed according to the Samuelson rule. However, since power system's are clearly an critical infrastructure, security margins may be involved. How these security margins offset market-based decision processes on the value of reliable electricity supply is point of future research.

Second, we find with regards to non-event reserve requirements that a determination of the requirements based on the proposed cost analysis leads to a reduction of required reserves. Further, financial incentives for renewable-energy in-feed and demand units to adhere to the forecasted schedule are created.

Future research includes the determination of the demand and supply curves with respect to event-based reserve requirement and the avoidance of non-event based imbalances. Further, the proposed market design framework will be more elaborated, especially the costs allocation of non-event based reserves requirements. Finally, the impact of dispersed renewable energy in-feed versus the concentrated in-feed in our study has to be assessed. This study may then be augmented with transmission security consideration.

VII. Acknowledgment

Research was supported by the European Commission under project MoVeS, FP7-ICT-257005.

APPENDIX

A. Definition of Optimization Constraints

Numbers and Indices

N_G, N_L, N_W	Number of generators, loads, and wind farms
N_{Br}, N_B, N_D	Number of lines, nodes, supply curves of loads to abate deviations
S, K, Z, Y, Q, R	Number of segments of piecewise linear cost/benefit curve for generators, loads, event-based up reserves, event-based down reserves, wind farms (abating deviations) and loads (abating deviations),
i, j, s, k, z, y	Indices for generators, loads, segments of marginal cost curve of generator, marginal benefit curves of energy, event-driven up-reserves, event-driven down reserves,
w, d, q, r	Indices for supply curves for deviation abatement of wind farms/demand units, segment of supply curves for deviation abatement of wind farms/demand units.
M_G, M_L, M_W	Generator, Load, wind farm connectivity matrix ("1" where it's connected, $[N_B \times N_G/N_L/N_W]$),

Parameters

$C_{start}^{i,t}/C_{noLoad}^{i,t}$	Start-up costs / No load costs of generation unit i at time t [mon.Unit/MW],
$R_{req}^{\tilde{t}}$	Required amount of non-event driven reserve capacity [MW],
M	Large constant,
$P_f^{w,t}$	Forcasted wind in-feed of unit w at time t,
$P_{max}^{i,t}/P_{min}^{i,t}$	Max./Minimal generation of unit i at time t,
$P_{En,max}^{j,t}/P_{En,min}^{j,t}$	Max./Minimal consumption of load j at time t,
$P_{Rup/Rdn,max}^{i,t}$	Maximal ramping up/down [MW/h] of unit i at time t,
$MC_{En,seg}^{i,s,t}$	Marginal cost of energy production of generator i in segm. s at time t,
$MB_{En,seg}^{j,k,t}$	Marginal benefit of energy consumption of demand j in segm. k at time t,
$MC_{evt_{up/dn},seg}^{i,s,t}$	Marginal cost of event-driven reserve production of generator i in segm. s at time t,
$MC_{nonevt_{up/dn},seg}^{i,s,t}$	Marginal cost of non-event driven production of generator i in segm. s at time t,
$MB_{evt_{up/dn},seg}^{j,z/y,t}$	Marginal benefit of event-driven reserves for demand j in segm. k at time t,
$MC_{abate,seg}^{w,q,t}$	Marginal cost of supplying abatement of deviations of in-feed w in segm. q at time t,
$MC_{abate,seg}^{d,r,t}$	Marginal cost of supplying abatement of deviations of demand d in segm. r at time t,
$PTDF_l^p$	Power Transfer Distribution Factor Matrix for lines l by power injection at nodes p,
f_l^{max}	Maximal loading of line l.
$\lambda^{p,t}$	Price at node p at time t (derived from unit commitment problem),

Variables

$P_{En}^{i,t}$	Energy generation [MW] of generation unit i at time t,
$P_{En}^{i,s,t}$	Energy generation [MW] in segment s of generation unit i at time t,
$P_{En}^{j,t}$	Energy demand [MW] by cons. j at time t,
$P_{En}^{j,k,t}$	Energy demand [MW] in segment k by consumer j at time t,
$P_{evt_{up/dn}}^{i,t}$	Scheduled up/down event-driven reserve capacity [MW] of unit i at time t,
$P_{evt_{up/dn}}^{i,s,t}$	Scheduled up/down event-driven reserve capacity [MW] in segm. s of unit i at time t,
$P_{evt_{up/dn}}^{t}$	Scheduled demand for up/down event-driven reserve capacity [MW] at time t,
$P_{evt_{up/dn}}^{z,t}$	Scheduled demand for up/down event-driven reserve capacity [MW] in segm. z at time t,
$P_{nonevt_{up/dn}}^{i,t}$	Scheduled up/down non-event driven reserve capacity [MW] of unit i at time t,
$P_{nonevt_{up/dn}}^{i,s,t}$	Scheduled up/down non-event driven reserve capacity [MW] in segm. s of unit i at time t,
$P_{abate}^{w,t}$	Scheduled amount of abated fluctuations [MW] of wind unit w at time t,
$P_{abate}^{w,q,t}$	Scheduled amount of abated fluctuations [MW] in segm. q of wind unit w at time t,
$P_{abate}^{d,t}$	Scheduled amount of abated fluctuations [MW] of demand unit d at time t,
$P_{abate}^{d,r,t}$	Scheduled amount of abated fluctuations [MW] in segm. r of demand unit d at time t,
$\tilde{R}_{reqrelax}^{t}$	Relaxed required amount of non-event driven reserve capacity [MW],
$u^{i,t}$	ON/OFF variable of generator i at time t,
$v^{j,t}$	Accepted bid of demand unit j at time t,
$u_{evt_{up/dn}}^{i,t}$	Binary variable of generator i at time t to provide event driven reserves,
$u_{nonevt_{up/dn}}^{i,t}$	Binary variable of generator i at time t to provide non-event driven reserves,
$E_G^{i,s,t}$	Bound of segment s of generator i at time t,
$E_L^{j,k,t}$	Bound of segment k of load j at time t,
$H_{up/dn}^{i,s,t}$	Spare capacity for event-driven reserves capacity of segment s, generator i at unit t,
$V_{up/dn}^{i,s,t}$	Spare capacity for non-event driven reserves capacity of segment s, generator i at unit t,
$LOC_{evt/nonevt}^{i,t}$	Lost opportunity costs of gen. i at time t for event-driven/non-event driven reserves,
$LOC_{evt/nonevt}^{i,s,t}$	Segment s of lost opportunity costs of gen. i at time t.

The shown constraints are partially based on the work of [19] and [38]. The system balance equations for energy and up/down event-driven reserves are given by:

$$\sum_{i=1}^{N_G} P_{En}^{i,t} - \sum_{j=1}^{N_L} P_{En}^{j,t} + \sum_{w=1}^{N_W} P_f^{w,t} = 0, \tag{15}$$

$$\sum_{i=1}^{N_G} P_{evt_{up/dn}}^{i,t} - P_{evt_{up/dn}}^{t} = 0, \tag{16}$$

The power balance for non-event driven reserve capacity is given by:

$$\tilde{R}_{req}^{t} - \sum_{w=1}^{N_W} P_{abate}^{w,t} - \sum_{d=1}^{N_D} P_{abate}^{d,t} = \tilde{R}_{reqrelax}^{t}, \tag{17}$$

$$\tilde{R}_{reqrelax}^{t} - \sum_{i=1}^{N_G} P_{nonevt_{up/dn}}^{i,t} = 0, \tag{18}$$

Constraints (19)-(21) state the capacity limits of generators and demand:

$$P_{En}^{G,i,t} + P_{evt_{up}}^{i,t} + P_{nonevt_{up}}^{i,t} \leq u^{i,t} P_{max}^{i,t}, \tag{19}$$

$$-P_{En_{seg}}^{i,1,t} + P_{evt_{dn,seg}}^{i,1,t} + P_{nonevt_{dn,seg}}^{i,1,t} \leq -u^{i,t} P_{min}^{i,t}, \tag{20}$$

$$v^{L,j,t}P_{En,min}^{j,t} \leq P_{En}^{L,j,t} \leq v^{L,j,t}P_{En,max}^{j,t}, \quad (21)$$

where $P_{En,min}^{L,j,t} = P_{En,max}^{L,j,t}$. Constraints (22)-(23) ensure that the sum of segmentwise power production and consumption equals the overall generation/consumption:

$$P_{En/(non)evt_{up/dn}}^{i,t} - \sum_{s=1}^{S} P_{En/(non)evt_{seg}}^{i,s,t} = 0, \quad (22)$$

$$P_{En/(non)evt_{up/dn}}^{j/1/1,t} - \sum_{k/z/y=1}^{K/Z/Y} P_{En/(non)evt_{up/dn}}^{j/1/1,k/z/y,t} = 0, \quad (23)$$

Constraints (24)-(26) are further segment-wise constraints for generation and demand:

$$P_{En_{seg}}^{i,s,t} + P_{evt_{up,seg}}^{i,s,t} + P_{nonevt_{up,seg}}^{i,s,t} \leq u^{i,t}[E_G^{i,s} - E_G^{i,(s-1)}], \quad (24)$$

$$v^{j,t}[E_L^{j,k} - E_L^{j,(k-1)}] \geq P_{En_{seg}}^{j,k,t}, \quad (25)$$

$$E_L^{j,0} = 0, \quad (26)$$

Constraints (27)-(34) are necessary to achieve a correct bidding for non-event driven reserves capacity (see also [19])

$$u_{evt/nonevt_{up}}^{i,s,t} \geq u_{evt/nonevt_{up}}^{i,(s+1),t}, \quad (27)$$

$$M \cdot MC_{evt/nonevt_{up,segm}}^{j,s,t} \geq u_{evt/nonevt_{up}}^{i,s,t}, \quad (28)$$

$$M \cdot u_{evt/nonevt_{up}}^{i,s,t} \geq MC_{evt/nonevt_{up,segm}}^{j,s,t}, \quad (29)$$

$$M \cdot [1 - u_{evt_{up}}^{i,(s+1),t}] - H_{up}^{i,s,t} \geq 0, \quad (30)$$

$$M \cdot [1 - u_{nonevt_{up}}^{i,(s+1),t}] - V_{up}^{i,s,t} \geq 0, \quad (31)$$

for $s = 1, ...(N_{G,segm} - 1)$ where,

$$H_{up}^{i,s,t} = [E_G^{i,s} - E_G^{i,(s-1)}] - P_{En_{seg}}^{i,s,t} - P_{evt_{up,seg}}^{i,s,t}, \quad (32)$$

$$V_{up}^{i,s,t} = \quad (33)$$

$$[E_G^{i,s} - E_G^{i,(s-1)}] - P_{En_{seg}}^{i,s,t} - P_{evt_{up,seg}}^{i,s,t} - P_{nonevt_{up,seg}}^{i,s,t}. \quad (34)$$

Note that if,

$$H_{up}^{i,s,t} \begin{cases} > 0 & \text{then } u_{evt_{up}}^{i,(s+1),t}, \\ = 0 & \text{then } u_{evt_{up}}^{i,(s+1),t}, \end{cases}$$

for $s = 1, ...(N_{G,segm} - 1)$, and if

$$V_{up}^{i,s,t} \begin{cases} > 0 & \text{then } u_{nonevt_{up}}^{i,(s+1),t}, \\ = 0 & \text{then } u_{nonevt_{up}}^{i,(s+1),t}, \end{cases}$$

for $s = 1, ...(N_{G,segm} - 1)$. The piecewise linear dn-reserve offer is given by constraints

$$u_{evt/nonevt_{dn}}^{G,i,s,t} \geq u_{evt/nonevt_{dn}}^{i,(s-1),t}, \quad (35)$$

$$M \cdot [1 - u_{evt_{dn}}^{i,(s-1),t}] - H_{dn}^{i,s,t} \geq 0, \quad (36)$$

$$M \cdot [1 - u_{nonevt_{dn}}^{i,(s-1),t}] - V_{dn}^{i,s,t} \geq 0, \quad (37)$$

$$M \cdot Bid_{evt/nonevt_{dn,segm}}^{j,s,t} \geq u_{evt/nonevt_{dn}}^{i,s,t}, \quad (38)$$

$$Bid_{evt/nonevt_{dn,segm}}^{j,s,t} \leq M \cdot u_{evt/nonevt_{dn}}^{i,s,t}, \quad (39)$$

for $s = 1, ...(N_{G,segm} - 1)$, where

$$H_{dn}^{i,s,t} = P_{En_{seg}}^{i,s,t} - P_{evt_{dn,seg}}^{i,s,t}, \quad (40)$$

$$V_{dn}^{i,s,t} = P_{En_{seg}}^{i,s,t} - P_{evt_{dn,seg}}^{i,s,t} - P_{nonevt_{dn,seg}}^{i,s,t}. \quad (41)$$

Note that if,

$$H_{dn}^{i,s,t} \begin{cases} > 0 & \text{then } u_{evt_{dn}}^{i,(s-1),t}, \\ = 0 & \text{then } u_{evt_{dn}}^{i,(s-1),t}, \end{cases}$$

and

$$V_{dn}^{i,s,t} \begin{cases} > 0 & \text{then } u_{nonevt_{dn}}^{i,(s-1),t}, \\ = 0 & \text{then } u_{nonevt_{dn}}^{i,(s-1),t}, \end{cases}$$

for $s = 1, ...(N_{G,segm} - 1)$.
The lost opportunity costs for event-driven and non-event driven reserves are given by constraints (42)-(45).

$$LOC_{evt/nonevt_{seg}}^{i,t} - \sum_{s=1}^{S} LOC_{evt/nonevt_{seg}}^{i,s,t} = 0, \quad (42)$$

$$LOC_{evt/nonevt_{seg}}^{i,s,t} = \quad (43)$$

$$M'_G[\lambda^{p,t} M_G P_{evt/nonevt_{seg}}^{i,s,t} - M_G Bid_{En,seg}^{i,s,t} P_{evt/nonevt_{seg}}^{i,s,t}], \quad (44)$$

$$LOC_{evt/nonevt_{seg}}^{i,s,t} \geq 0. \quad (45)$$

The up and down time limits for a generator are given by (46)-(50):

$$u_{it} = \begin{cases} 1 & \text{if } t' \leq t_i^{up} - u_{i0} \text{ and } t_i^{up} \geq u_{i0} \geq 0, \\ 0 & \text{if } t' \leq t_i^{dn} + u_{i0} \text{ and } -t_i^{dn} \leq u_{i0} \leq 0, \end{cases} \quad (46)$$

with

$$u^{i,t} - u^{i,(t-1)} \leq u^{G,i,t''}, \quad (47)$$

$$u^{i,(t-1)} - u^{i,t} \leq u^{G,i,t'''}, \quad (48)$$

$$t + 1 \leq t'' \leq t + t_i^{up} - 1 \text{ and } t = 2...T, \quad (49)$$

$$t + 1 \leq t''' \leq t + t_i^{dn} - 1 \text{ and } t = 2...T, \quad (50)$$

The ramping limits of a generator are given by equations (51)-(56)

$$P_{En}^{i,t} - P_{En}^{i,(t-1)} \leq \max[P_{Rup,max}^{i,t}, P_{min}^{i,t}], \quad (51)$$

$$P_{En}^{i,(t-1)} - P_{En}^{i,t} \leq \max[P_{Rdn,max}^{i,t}, P_{min}^{i,t}], \quad (52)$$

$$1 - u^{i,t} + u^{i,(t-1)} \leq M[1 - aux^{i,t,1}], \quad (53)$$

$$P_{En}^{i,t} - P_{En}^{i,(t-1)} - P_{Rup,max}^{i,t} \leq Maux^{i,t,1}, \quad (54)$$

$$1 + u^{i,t} - u^{i,(t-1)} \leq M[1 - aux^{i,t,2}], \quad (55)$$

$$-P_{En}^{i,t} + P_{En}^{i,(t-1)} - P_{Rdn,max}^{i,t} \leq Maux^{i,t,2} \quad (56)$$

$$\sum_{i=1}^{N_G} \min .[P_{max}^{i,t}, P_{En}^{i,t} + P_{Rup,max}^{i,t}] \geq \sum_{j=1}^{N_L} P_{En}^{j,t} - \sum_{w=1}^{N_W} P_f^{w,t} + P_{evt_{up}}^t + \tilde{R}_{reqrelax}^t, \quad (57)$$

$$\sum_{i=1}^{N_G} \min .[P_{min}^{i,t}, P_{En}^{i,t} - P_{Rdn,max}^{i,t}] \geq \sum_{j=1}^{N_L} P_{En}^{j,t} - \sum_{w=1}^{N_W} P_f^{w,t} - P_{evt_{dn}}^t - \tilde{R}_{reqrelax}^t, \tag{58}$$

The transmission constraints are modeled as,

$$-f_l^{max} \leq PTDF_l^p(M_G \cdot P_{En}^{i,t} - M_L \cdot P_{En}^{j,t}) \leq f_l^{max}. \tag{59}$$

B. Additional Model Parameters

Table I shows additional parameters used for the respective simulations.

TABLE I: Additional simulation parameters

Parameter/Time Period	1 - 24		1 - 24
ϵ_{en}	-0.25	$\eta^{W,w,t}$	0.15/0.3/0.6
$\epsilon_{evt\ res}$	$[-0.25, -0.75]$	$\eta^{L,d,t}$	0.15/0.3/0.6
$A_{en}^{j,t}$	$2 \cdot \sum_{j \in N_L} P_{En}^{j,t}$	$B^{W,w,t}$	5
$A_{evt\ res}^{j,t}$	$\frac{1}{2} \cdot \sum_{j \in N_L} P_{En}^{j,t}$	$B^{L,d,t}$	5
$Bid\ Markup$	[0%, 20%]	γ	[20%]

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