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Variable Energy Resource Induced Power System Imbalances: Mitigation by Increased System Flexibility, Spinning Reserves and Regulation

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***Abstract*—The impact of variable energy resources (VER) on power system reserve and regulation requirements has been a subject of extensive research in recent years. However, the conclusions about the scale of the impact diverge, since most of the results are obtained from specific case studies. This paper proposes a generalized approach to the assessment of power system reserve and regulation requirements. It uses a power system enterprise model that consists of three layers: the physical grid, resource scheduling and balancing operations. Resource scheduling is modeled as a security-constrained unit-commitment (SCUC) problem. The balancing layer consists of three components, namely the regulation service, the real-time market and operator manual actions. The real-time market is implemented as a security-constrained economic dispatch (SCED) problem. The IEEE RTS96 reliability test system is used for the physical layer. Three main resources contributing to the balancing of power system are studied: reserves, regulation and generator ramping rates. Their impacts on power system imbalance mitigation in the presence of VER is studied.**

***Index Terms*—Power system imbalances, wind integration**

I. Introduction

The impact of variable energy resource (VER) penetration on power system operations and planning has been the subject of extensive research in recent years [1], [2]. Here, significant wind and solar penetration adds new levels of variability and uncertainty to power systems; thus impeding balanced operations as defined by the North American Electric Reliability Corporation (NERC)’s control performance standards (CPS). The main conclusion of such studies is that renewable energy integration increases power system reserves and regulation requirements. However, most of these results are based on specific case studies that commedsafnt on the sufficiency of a power system’s flexibility in relation to VER penetration [3], [4], thus limiting their generalizability [5]. Consequently, a recent review has motivated the need for holistic assessment methods [6].

To that effect, this paper seeks to develop a methodology of power system imbalance mitigation characterization in the case of VER penetration. It draws as inspiration the concept of integrated enterprise control in which both physical as well as enterprise processes are modeled to gain an understanding of the holistic system behavior [7]. In such a way, the variability of renewable energy resources can be viewed as an input disturbance which the (enterprise) power system systematically manages to deliver attenuated power system imbalances. The power system is modeled in terms of its key characteristics: flexibility (ramping capabilities of conventional generation units), power spinning reserve and regulation capacity. Furthermore, the enterprise power system modeling includes three layers, namely resource scheduling, balancing actions, and a physical layer which represents the buses, transmission lines, loads and generators. While it is not possible within the scope of this paper to model all enterprise power system processes, the ones most relevant to power system imbalances are captured: unit commitment, regulation service, real-time market, and operator manual actions.

This paper is the second of two to systematically study power system imbalances. The first paper [8] addresses the development of an assessment methodology for power system imbalances. Such an approach facilitates making case-independent conclusions. This paper focuses on assessing a power system’s imbalance mitigation capabilities based upon their physical as well as enterprise control characteristics. Imbalances are presented in terms of the corresponding levels of CPS compliance.

II. Background

A. Power System Imbalances

Power system reliable operations require the balance of generation and consumption. The mismatch between generation and consumption also creates a mismatch between mechanical and electrical torques applied on generators. If generation exceeds consumption, generators accelerate, and the system frequency increases. Likewise, if consumption exceeds generation, generators decelerate, and the system frequency decreases. Deviations of the system frequency from the rated value may have a damaging effect on power system equipment, that is designed for working at a specific frequency.

The instantaneous power balance in the system with ΔF frequency deviation is given by the following equation [9]:

$$\Delta P_m - \Delta P_D = D_F \Delta F + \frac{dW_k}{dt} \tag{1}$$

where ΔP_m and ΔP_D are changes in mechanical power and electrical power demand correspondingly, D_F is the aggregated damping parameter of generators, and dW_k/dt is the rate of change in kinetic energy.

For a specific control area power generation and consumption imbalance is called area control error (ACE). ACE is a crucial parameter of power system imbalance monitoring and performance assessment. For steady-state simulations, dW_k/dt is zero, and Equation (1) takes the following form:

$$ACE = D_F \Delta F \tag{2}$$

Equation (2) is used to measure ACE in real power systems. First, the deviation of the system frequency from rated value is measured, then ACE is calculated from (2).

B. Imbalance Mitigation

Power systems always experience imbalances due to forecasting uncertainties, generator outages, equipment failures and other contingencies. Any imbalance triggers a counter action from the power system to mitigate it. Traditionally, the power system dynamics are classified as a hierarchy of dynamics: primary, secondary and tertiary [**?**]. Primary dynamics and control address transient stability phenomena in the range of 10-0.1Hz [**?**]. These represents the inertial response of generators and loads and may be controlled by generator output adjustments implemented by automatic generation control and automatic voltage control [9]. Secondary and tertiary control are managed by independent system operators and balancing authorities and are the main focus of this work. Detailed descriptions of these techniques are presented in the next section.

C. Control Performance Standards

Implementation of all balancing actions, however, does not eliminate imbalances completely. As a matter of fact, ideal generation and consumption balance is not required. The North American Electric Reliability Corporation (NERC) defines the requirements of imbalance mitigation, called control performance standard (CPS) [10]. According to *Standard BAL-001-0.1a*, each balancing authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit L_{10}. The value of L_{10} is obtained from the system properties. Thus, this standard provides a tool for balancing performance assessment.

III. Methodology and Simulation Setup

The power system enterprise model, used in this study, is comprised of three interconnected layers: the physical grid, resource scheduling and balancing actions. The conceptual diagram of the model is presented in Fig. 1.

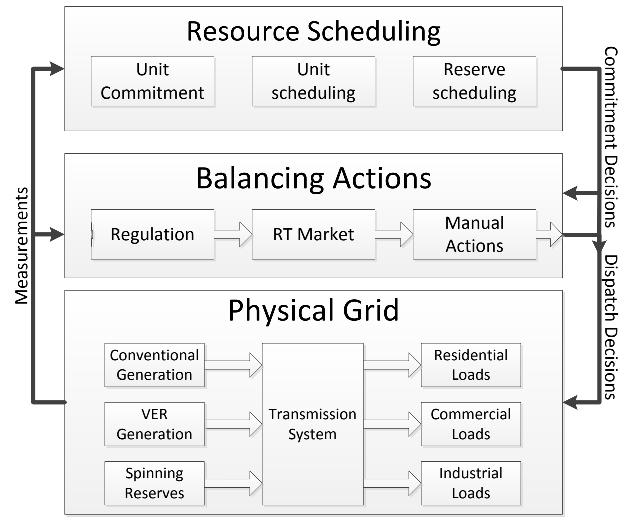

Fig. 1. Conceptual model of power system operations

Resource scheduling occurs prior to the operating day. At this point, the optimal set of generation units for the operating day is defined, along with their schedules. Also, during the resource scheduling, the required reserve amount is scheduled. The scheduled resources are then managed in the real-time to maintain power system balance. Three balancing actions, namely regulation, real-time market and operator manual actions, contribute to the balancing of the system. Separate components of the model are described in detail in the following subsections.

A. Resources Scheduling

Reliable operations of the power system start one day prior the operating day with the scheduling of necessary resources. According to Fig. 1, it accomplishes three parallel actions, namely: unit commitment, unit scheduling and reserve scheduling.

1) Generation Commitment and Scheduling: The ultimate goal of the scheduling layer is to choose the right set of generation units, that are able to meet real-time demand requirements with minimum cost, and define their schedules. This procedure is implemented via a software-based optimization tool, called Security-Constrained Unit commitment (SCUC), which has a mathematical formulation in the form of a linear mixed-integer program [11]:

$$\min \quad \sum_{t=1}^{24} \sum_{i=1}^{N_G} (w_{i,t} C_i^F + C_i^G P_{i,t}^G + w_{i,t}^u C_i^U + w_{i,t}^d C_i^D) \tag{3}$$

$$\text{s.t.} \quad \sum_{i=1}^{N_G} P_{i,t}^G = P_t^D \tag{4}$$

$$-R_i^{G,max} \Delta T \leq P_{i,t}^G - P_{i,t-1}^G \leq R_i^{G,max} \Delta T \tag{5}$$

$$w_{i,t} P_i^{G,min} \leq P_{i,t}^G \leq w_{i,t} P_i^{G,max} \tag{6}$$

$$w_{i,t} = w_{i,t-1} + w_{i,t}^u - w_{i,t}^d \tag{7}$$

$$\sum_{i=1}^{N_G} w_{i,t} \left(P_i^{G,max} - P_{i,t}^G \right) \geq P_{res} \tag{8}$$

where the following notations are used:

$C_i^F, C_i^G, C_i^U, C_i^D$	fixed, generation (fuel), startup and shutdown costs of generator i
$P_{i,t}^G$	power output of generator i at time t
P_t^D	total demand at time t
$P_i^{G,max}, P_i^{G,min}$	max/min power limits of generator i
$R_i^{G,max}$	maximum ramping rate of generator i
ΔT	scheduling time step, normally, 1 hour
N_G	number of generators
$w_{i,t}$	ON/OFF state of the generator i
$w_{i,t}^u, w_{i,t}^d$	startup/shutdown indicators of generator i
P^{res}	system reserve requirements

The objective of this model is to find the optimal set of generators and their schedules, that will meet the demand with minimal total operating cost of the system. Constraint (4) is the power balance equation, required to keep the system balanced. The other two constraints, (5) and (6), are the physical limitations on generators' ramping rates and power outputs respectively. The solution to this mathematical program yields optimal $w_{i,t}$ commitment and $P_{i,t}^G$ generation schedules for each generator.

2) Adequacy of the Scheduled Generation: The unit commitment model takes power system characteristics, such as generation levels, ramping limits, and demand forecasts as inputs. Later, the scheduling of resources is performed to satisfy those requirements. However, the scheduled resources rarely match the real-time requirements due to a series of objective limitations. Three main factors can be distinguished as potentially causing this mismatch.

First, the information about real-time power demand is limited to the day-ahead demand forecast. Even the best possible forecasting techniques are able to provide the demand forecast with limited accuracy.. The resulting forecast error is the power mismatch that emerges during real-time operations.

The second factor is the difference between resource scheduling and real-time balancing time steps. Normally, the unit commitment model schedules resources with a 1 hour time resolution. During these 1 hour intervals, the generation schedules does not change, which makes it practically impossible to match the scheduled generation to the variations of the load. Ideally, the presence of a perfect forecast may only guarantee matching the scheduled generation and the average demand for 1 hour intervals. The deviations of the actual demand from its average value on 1 hour intervals are referred to as intra-hour variations.

The third factor is lossless transmission assumption reflected in constraint (4). Generally, as a direct consequence of the power flow equations, the power balance consists of three components, namely generation, demand and transmission line losses [12]:

$$\sum_{i=1}^{N_G} P_{i,t}^G = P_t^D + P_t^{LOSS} \tag{9}$$

where P_t^{LOSS} is the total transmission loss in the system. Exclusion of the loss component is necessary to maintain a linear SCUC model. As a result, some portion of the scheduled generation is *'consumed'* by transmission lines and does not fill the demand.

3) Reserve Scheduling: The discussion of the previous section establishes the objective limitations that make matching the scheduled generation and the actual demand impossible. Normally, this issue is easily solved by the procurement of reserve generation in addition to the scheduled generation. The reserve requirements are settled based on the existing standards and the experience of power system operators. Constraint (8) in the unit commitment model reflects the reserve procurement, where P_{res} is the reserve requirement.

One important fact is neglected in the formulation of the unit commitment problem, however. Generally, the scheduling process has two components. The scheduling of generation and the scheduling of the necessary ramping capabilities are reflected in the constraints (4) and (5) respectively. The symmetry of these two components becomes more obvious if constraint (5) is split into two separate constraints as follows:

$$R_{i,t}^G = \left(P_{i,t}^G - P_{i,t-1}^G \right) / \Delta T \tag{10}$$

$$R_i^{G,min} \leq R_{i,t}^G \leq R_i^{G,max} \tag{11}$$

where $R_{i,t}^G$ is the difference between consecutive values of scheduled generation and can be referred to as scheduled ramping. As a result, the differences between day-ahead generation scheduling and real-time requirements are also reflected in the ramping domain. Real-time ramping requirements tend to be always different from the day-ahead scheduled value. However, the provision of ramping reserves is not included in the unit commitment model.

In the case of ramping scheduling, it is assumed that the committed generation units have enough ramping capabilities to follow variations of the load. This assumption is valid for traditional power systems with slowly changing load. However, the integration of VER is likely to increase the variability of the net load. As a result, the system may chronically suffer from not enough ramping capabilities.

To overcome this problem, the provision of ramping reserves is incorporated into an enhanced unit commitment model for use in this study. After the proposed modifications, the unit commitment model transforms into the following form:

$$\min \quad \sum_{t=1}^{24}\sum_{i=1}^{N_G}\left(w_{i,t}C_i^F + C_i^G P_{i,t}^G + w_{i,t}^u C_i^U + w_{i,t}^d C_i^D\right) \tag{12}$$

$$\text{s.t.} \quad \sum_{i=1}^{N_G} P_{i,t}^G = P_t^D \tag{13}$$

$$R_{i,t}^G = \left(P_{i,t}^G - P_{i,t-1}^G\right)/\Delta T \tag{14}$$

$$w_{i,t}P_i^{G,min} \le P_{i,t}^G \le w_{i,t}P_i^{G,max} \tag{15}$$

$$-R_i^{G,max} \le R_{i,t}^G \le R_i^{G,max} \tag{16}$$

$$w_{i,t} = w_{i,t-1} + w_{i,t}^u - w_{i,t}^d \tag{17}$$

$$\sum_{i=1}^{N_G} w_{i,t}\left(P_i^{G,max} - P_{i,t}^G\right) \ge P_{res} \tag{18}$$

$$\sum_{i=1}^{N_G} w_{i,t}\left(P_{i,t}^G - P_i^{G,min}\right) \ge P_{res} \tag{19}$$

$$\sum_{i=1}^{N_G} w_{i,t}\left(R_i^{G,max} - R_{i,t}^G\right) \ge R_{res} \tag{20}$$

$$\sum_{i=1}^{N_G} w_{i,t}\left(R_i^{G,max} + R_{i,t}^G\right) \ge R_{res} \tag{21}$$

where constraints (20) and (21) are for ramping up and ramping down reserves respectively. Also, the introduction of ramping reserve requirements gives a lever by which to vary the flexibility of the system. This is important for testing the impact of system flexibility on imbalance mitigation.

4) Reserve Requirements and Scheduled Reserves: The reserve procurement via constraint (8) in the unit commitment guarantees that the actual amount of reserves is greater or equal to the reserve requirement P_{res}. The left-hand-side is the difference between the maximum available generation capacity and the total scheduled generation, which is, by definition, the actual amount of available reserves.

Since the left-hand-side of constraint (8) can only change discretely with the commitment of new generation units, the actual reserves usually exceed the minimum required amount. The difference between the available reserves and the minimum requirement depends on different factors, such as the generation portfolio of the system, the demand level, etc. Generally, this difference may have any value in a range from 0 to the largest generation unit capacity.

This kind of situation may significantly affect the results of VER integration studies. For example, in power systems with mostly large generation units, available reserve capacity is likely to exceed minimum reserve requirement significantly. This creates the possibility of VER integration into the power system without any additional requirements. As a result, one may conclude, that the integration of VERs into the system brings no additional requirements on reserves, which is not generally true.

To increase generalization capabilities of the results in the current study, it is assumed that the actually available reserves and the minimum requirements always match. In other words, there is no extra reserve capacity in addition to the requirement. Obviously, this is the worst case scenario, that shows how big the imbalances can be and how low CPS can drop. This approach reduces the case-dependency of results.

The quantity of actual reserves is limited by manipulating the maximum generation levels of scheduled generators after the SCUC program has completed. First, the scaling factor is defined as a ratio of the required reserve to the actually scheduled reserves:

$$\alpha_t^P = \frac{P_{res}}{\sum\limits_{i=1}^{N_G} w_{i,t}\left(P_i^{G,max} - P_{i,t}^G\right)} \tag{22}$$

Equation (22) shows that the scaling factor depends on time. This is because the unit commitment schedules a different amount of reserves for different time intervals. The scaling factor is then used to change the maximum output of generators, so that the available reserves equal the reserve requirements:

$$P_{i,t}^{G,max} = P_{i,t}^G + \alpha_t^P \cdot \left(P_i^{G,max} - P_{i,t}^G\right) \tag{23}$$

Note, that the maximum outputs of generators $P_{i,t}^{G,max}$ used in the real-time market change over time. While this is a non-physical situation, it is required to demonstrate the impact of increased reserves on the system imbalances. Failing to do so would cause the quantity of actual reserves depending on the inequality in the SCUC program.

The same reasoning applies to the scheduling of ramping reserves. The scaling factor for ramping reserves is defined similar to generation reserves:

$$\alpha_t^R = \frac{R_{res}}{\sum\limits_{i=1}^{N_G} w_{i,t}\left(R_i^{G,max} - R_{i,t}^G\right)} \tag{24}$$

Accordingly, the adjusted maximum ramping rates of the generators are given by the following equation:

$$R_{i,t}^{G,max} = R_{i,t}^G + \alpha_t^R \cdot \left(R_i^{G,max} - R_{i,t}^G\right) \tag{25}$$

Unlike generation and ramping reserves, the provision of regulation reserves is market based. The requirements are announced in the market, and the generators with the cheapest offers are chosen. As a result, the actually available regulation reserves always match the requirement.

B. Balancing Actions

Day-ahead resource scheduling defines the set of generators available for the operating day. During the operating day, scheduled resources are managed in real-time to ensure balancing of the system at any moment. Fig. 1 shows that balancing actions consist of three components operating at different timescales: regulation, real-time market and operator manual actions. Each component is described in detail in further subsections.

1) Measurement of the Power System State and Imbalances: Effective balancing of the power system requires up-to-date information about the system state. In real power systems, this function is carried out by the state estimator, which provides information about bus voltages and angles, generation and consumption levels, and the ACE.

Rather than introducing the complexity and errors associated with state estimation implementation, power flow analysis is used to "estimate" the state of the system. The values of bus voltages and angles are obtained at every simulation step for the given levels of generation and consumption. This approach is equivalent to perfect state estimation.

Referring to Equation 2, the ACE estimation requires measurement of the system frequency deviation. However, for steady-state simulation the concept of frequency is not applicable. Instead, a designated slack generator consumes the mismatch of generation and consumption to make steady-state power flow equations solvable. Therefore, for steady state simulations the power system imbalances are measured as the output slack generator [9].

2) Regulation Service: Generally, the regulation service is represented by a dynamic model [12]. However, for steady state simulations a simplified model is implemented. At a time scale slower than 1 minute, the effective transfer function simplifies to a gain with saturation limits. Thus, in the current study, the regulation is implemented as follows. At each simulation step, the regulation service responds to the imbalances by moving its output to the opposite direction. The regulation output changes until imbalance mitigation or regulation service saturation.

3) Real-Time Market: The real-time market operates in parallel to the regulation service to suppress imbalances, but in a slower time-scale. It moves available generator outputs to new setpoints in the most cost-efficient way. In its original formulation, generation re-dispatch is implemented as a non-linear optimization model, called AC optimal power flow (ACOPF) [13]. Due to problems with convergence and computational complexity [11], most of the US independent system operators (ISO) moved from ACOPF to linear optimization models. The most commonly used models is Security-Constrained Economic Dispatch (SCED), formulated as an incremental linear optimization program [14]:

$$\min \quad \sum_{i=1}^{N_G}(b_i \Delta P_{i,t}^G + 2c_i P_{i,t}^G \Delta P_{i,t}^G) \tag{26}$$

$$\text{s.t.} \quad \sum_{i=1}^{N_B}(1-\gamma_{i,t})(\Delta P_{i,t}^G - \Delta P_{i,t}^L) = 0 \tag{27}$$

$$\sum_{i=1}^{N_B} a_{l,i,t}(\Delta P_{i,t}^G - \Delta P_{i,t}^L) \leq F_l^{max} - F_{l,t} \tag{28}$$

$$-R_i^G \Delta t \leq \Delta P_{i,t}^G \leq R_i^G \Delta t \tag{29}$$

$$P_{i,t}^G - P_i^{G,min} \leq \Delta P_{i,t}^G \leq P_i^{G,max} - P_{i,t}^G \tag{30}$$

where the following notations are used:

b_i, c_i	generator i offer curve linear and quadratic coefficients
$\Delta P_{i,t}^G, \Delta P_{i,t}^L$	bus i incremental generation and load
$F_{l,t}, F_l^{max}$	line l power flow level and flow limit
N_B	number of buses
$\gamma_{i,t}$	bus i incremental transmission loss factor
$a_{l,i,t}$	bus i generation shift distribution factor to line l
Δt	real-time market time step, normally, 5 minutes.

The use of incremental values for generation and load allows the incorporation of sensitivity factors and the linearization of the program. Sensitivity factors establish the linear connections between changes in power injections on buses and state-related parameters of the system [15].

Two sensitivity factors are used in the current model, namely the incremental transmission loss factor (ITLF) and the generation shift distribution factor (GSDF). ITLF for bus i shows how much the total system losses will change, if the injection on bus i increases by a unit [16]:

$$\gamma_{i,t} = \frac{\partial P_t^{LOSS}}{\partial P_{i,t}} \tag{31}$$

where P_t^{LOSS} is total system loss at moment t, $P_{i,t}$ is the power injection at bus i. The incorporation of ITLF into the model results in a linearized power balance constraint (27).

The GSDF shows how much the power flow in line l changes if the injection on bus i increases by a unit [16], [17]:

$$a_{l,i,t} = \frac{\partial F_{l,t}}{\partial P_{i,t}} \tag{32}$$

The incorporation of the GDSF into the model results in a linearized line flow limit constraint (28).

The other two constraints (29) and (30) are the physical limits of the generator ramping rates and outputs. The objective function in Equation (26) is the minimization of total generation cost. The values for b_i and c_i are the linear and quadratic coefficients of generator offer curves submitted for day-ahead scheduling.

Observation of the model shows that some input parameters, such as $P_{i,t}^G$, $F_{l,t}$, $\gamma_{i,t}$, $a_{l,i,t}$, depend on the current state of the system. These parameters are calculated before each SCED iteration based on a full AC power flow analysis in what are called hot start models in the literature [14].

4) Operator Manual Actions: In the normal operating mode of the power system, the regulation service and the real-time market are able to maintain the generation and consumption balance effectively. The available generation reserves and the generator ramping rates are enough to follow the slowly changing load. However, in the case of contingencies, the situation changes. A sudden outage of a major generation unit creates large imbalances that cannot be mitigated by real-time markets and regulation services. Online generation units do not have enough reserve capacity and enough ramping rates to fill the gap quickly. These kinds of situations require system operator manual actions, in the form of deployment of contingency reserves, decisions on the location of activated reserves, etc. Manual actions, unlike the other two components of balancing, have no dedicated operations timescale and are used as necessary.

In the absence of operator models in the literature, their actions are implemented as follows. The system imbalances are monitored during the interval of simulations. The trigger of operator manual intervention into the balancing procedure works, when the actual imbalances exceed 80% of the largest generation unit. The actions of the operators include balancing of the system manually and bringing new generation units online to suppress imbalances.

IV. Case Study

In this case study, the mitigation of power system imbalances by manipulations of generation, ramping and regulation reserves is tested. Three different mitigation scenarios are simulated. During each scenario, one of three reserves are changed in a reasonable range, while others stay constant. This approach allows the study of the impact of a particular reserve on mitigation of the imbalances. The performance of balancing actions is evaluated by compliance to CPS's.

Before these three scenarios, a traditional power grid without wind integration is simulated to determine the amount of reserves and regulation that the traditional system needs to maintain the balance. This approach makes sure that any imbalances are the results of wind integration.

The scenarios are implemented as steady-state simulations in the Matlab environment. The simulations run for one week period with a time step of 1 minute that corresponds to the regulation timescale. It is assumed that faster dynamics are mitigated by system inertia and load response.

A. Test System

The IEEE RTS-96 reliability test system is used as the physical grid model [18]. It is composed of three nearly identical control areas, with a total of 73 buses and 99 generators. The yearly peak load is 8550MW.

B. Incorporation of Wind and Load Data

Wind and load data from Bonneville Power Administration repositories [19] are used for the current case study. The best available data has 5-minute resolution, which does not satisfy the requirement of simulations with 1-minute time step. This difficulty is overcome by up-sampling the available data to 1-minute resolution. The up-sampling process is performed with the use of *sinc* functions to not introduce distortions into the power spectrum and not change the spectral width [20].

VER integration into the actual physical system requires an allocation to the system buses. This choice defines potential congestions occurrences in the system, which may significantly alter the results of imbalances for the same scenario. Since congestions are outside the score of the research, the VER capacity distribution is implemented in a way that minimizes congestion probabilities. Wind generation on each bus is proportional to the system load on that bus. As a first analysis, the temporal power generation profile of each wind turbine across the topology is assumed to be entirely correlated spatially. Future work can generalize this model to investigate systematic approaches to partial geographic correlations to confirm recent empirical evidence in this regard [21]. Due to the correlation of temporal profiles, all VER generation sources have the same variability and forecast error, which allows these parameters to be addressed in aggregate.

C. Simulation Scenarios

Three simulation scenarios are developed to study the mitigation of imbalances by enhancing three characteristics of power system: generation, ramping and regulation reserves. Each simulation scenario is conducted by varying a single parameter while holding all other parameters equal. Brief descriptions of each scenario are presented in the following paragraphs.

Scenario 0: Balancing of the traditional power system. The traditional power system is simulated without wind integration. This is the base case scenario, and defines reserve requirements for balancing the traditional system.

Scenario 1: Imbalance mitigation by increasing generation reserves *ceteris paribus*.

Scenario 2: Imbalance mitigation by increasing regulation reserves *ceteris paribus*.

Scenario 3: Imbalance mitigation by increasing ramping reserves *ceteris paribus*.

V. Simulation Results and Discussion

VI. Conclusion

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