

Sizing of Energy Storage for Grid Inertial Support in Presence of Renewable Energy

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Abstract—Penetration of renewable energy resources (RERs) in the power grid continues to increase as we strive toward a greener environment for the future. While they have many advantages, most RERs possess little or no rotational kinetic energy, thereby threatening the frequency stability of future power grids. Energy storage systems (ESSs) can be used to mitigate this problem, as they are capable of providing virtual inertia to the system. This paper proposes a novel analytical approach for sizing ESSs to provide inertial support to the grid and maintain frequency stability in presence of RERs. This method analytically estimates the total inertia of the system using probability distributions of the outage states of conventional generators and RERs. RERs are modeled as multi-state units, considering the variability of their output power due to changes in weather conditions and also the forced outages of their equipment. The ESS is utilized to provide virtual inertia to the grid in the form of active power once the estimated system inertia falls below the minimum required during a disturbance. The efficacy of the proposed approach is tested on the IEEE 39 bus system and the results obtained by the analytical approach are validated using Monte Carlo simulation.

Index Terms—Energy storage, frequency stability, reliability, renewable energy, virtual inertia.

NOMENCLATURE

Variables

p_{ci}	Probability of synchronization of unit i .
q_{cj}	Probability of unit j not being synchronized with the system.
E_i^G	Expected energy of unit i .
G_i	Capacity of conventional unit i .
H_i	Inertia constant of machine i .

L_e	Random variable (continuous) representing equivalent load of system.
L	Random variable (continuous) representing total load of system.
X	Random variable (continuous) representing outage states of system.
H_r	Random variable (discrete) representing equivalent inertia of system.
p_{cw}	Probability of synchronization of a wind farm.
CV_w	Capacity value of wind farm.
P_w	Additional load supported due to addition of wind farm of nameplate capacity G_w .
$p_{ws,i}$	Probability of wind being in state i .
P_m	Mechanical power input.
P_e	Electrical power output.
f_s	Nominal frequency of the system.
S	Nominal rating of the system.
$\Delta f_{\max}$	Maximum frequency deviation of the system.
H_{ESS}	Inertia contribution from the ESS.
$H_{\min}$	Minimum inertia required by system to maintain frequency stability.
P_{ESS}	Active power contribution from the ESS to provide inertia H_{ESS} .

Sets

U	Set of generators synchronized with the system.
D	Set of generators not synchronized with the system.

Generator Governor Parameters

H	Equivalent inertia constant of system.
D	Load damping constant.
K_i	LFC controller of machine i .
R_i	Equivalent regulation constant of machine i .
F_i	Fraction of turbine power generated by high pressure (HP) unit of machine i .
T_i	Governor Time constant of machine i .
Δf	Frequency deviation.
ΔP_L	Load disturbance in p.u.

I. INTRODUCTION

POWER grids across the world are undergoing remarkable changes in recent times fueled by extensive integration of renewable energy resources (RERs). While it has been well established that RERs help to alleviate environmental concerns,

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the high penetration of these resources poses some serious challenges to the reliability and stability of the power grid due to their intermittent nature and low-inertia characteristics. In the event of an imbalance in the system, the rotational kinetic energy stored in the rotor of the conventional synchronous generators is used to provide inertial support to the grid, thus restoring frequency stability. However, RERs like wind or solar are interfaced with the grid through power electronic devices like inverters, thus limiting their capabilities of providing inertial support. In this context, this paper proposes a novel analytical approach for sizing ESSs to maintain frequency stability of the grid in presence of RERs.

A. Discussion of Prior Art

Inverter-based resources are incapable of providing any mechanical inertial response, thus unable to support frequency stability of the grid [1], [2]. Several studies have shown that the replacement of conventional generators with RERs causes reduction of system inertia, which leads to an increased rate of change of frequency (RoCoF) and lower frequency nadirs [3], [4]. Independent system operators like Electric Reliability Council of Texas (ERCOT) [5] and regulatory bodies like North American Electric Reliability Corporation (NERC) [6] have also reported a reduction in frequency response due to the increasing penetration of RERs. Hence it is necessary to develop new approaches and technologies to combat this lack of inertia and avoid critical operating conditions and contingencies in presence of RERs.

Among the various solutions available for alleviating the aforementioned concerns, the concept of virtual inertia has been widely proposed in the literature [7]–[9]. Virtual inertia can be defined as the controlled contribution of electrical torque from a unit that is proportional to the RoCoF at the terminals of the unit [10] and can be implemented by means of ESSs, RERs, power electronic devices, and control algorithms [11]. In [12], the authors propose a control algorithm to minimize frequency disturbances in the system due to reduced inertia using ESS. Reference [13] solves the problem of reduced inertia in the system by determining the synthetic inertia and droop co-efficient of distributed energy resources (DERs) such that the frequency stability of the grid is maintained. This work focuses on the optimal participation of DERs in providing inertial and primary frequency response support to the grid. Reference [14] discusses the different ways by which power electronic converters can be controlled to behave like virtual synchronous machines. Since ESS are fast-acting devices with high ramping capabilities, they are well-suited for providing virtual inertia to the system. For this purpose, ESSs need to be sized accurately, depending on the system requirements. The problem of ESS sizing for virtual inertia support has been explored in [15]–[18]. In [15], the authors have presented a method to estimate the size of ESS to enhance inertial response of a power system in the presence of high wind penetration level although a loss of system inertia due to component failures was not considered. Probabilistic methods for sizing ESS under high RER penetration considering the loss of inertia due to component failures has been studied

in [16], [17] and a techno-economic framework for sizing of ESS is proposed in [18]. However, all the aforementioned works have used simulation techniques that can be computationally expensive.

B. Summary of Contribution

This paper proposes an *analytical* method that solves the problem of reduced system inertia due to increased RER penetration. Compared to traditional approaches that are based on simulation, analytical methods afford several benefits. Apart from being computationally less demanding, analytical approaches offer a solid mathematical foundation, based on which more complex problems can be solved. Besides, analytical models allow a more intuitive understanding of the problem and often provide the flexibility of performing back-of-the-envelope calculations as the intricacies of the problem evolve. For example, the approach proposed in this paper can be used as a foundation for solving more complicated problems such as optimal planning or economic dispatch while maintaining frequency stability of the grid with the aid of an ESS. Even if simulation becomes necessary for these more complex problems, the utilization of the analytical model can help reduce both the complexity and the computational burden, and even be used in frameworks involving real-time dispatch. To demonstrate the efficacy of the proposed analytical approach, we have used simulation techniques to validate the results obtained from the proposed analytical method.

The analytical approach that we propose in this paper is based on estimating the expected inertia of the generating resources of the system, including conventional generators and RERs. The amount of inertia present in any system constantly varies due to generator outages and the replacement of conventional units with RERs. As the system inertia fluctuates due to the aforementioned reasons, there might be instances when the system will not possess adequate inertia to maintain frequency stability after a disturbance occurs and before primary frequency response is activated. In such situations, ESSs can provide virtual inertia to the system at a fast rate and maintain frequency stability. For this purpose, ESSs need to be sized accurately, so that they can compensate for the lost inertia.

Considering the loss of inertia due to the two most common issues, generator outages, and RER penetration, we propose an analytical approach that is capable of estimating the size of ESS required to provide inertial support to the grid. This proposed approach involves the construction of a probability distribution of the system inertia, from which its expected value is calculated. While calculating the probability distribution of system inertia, we have also developed a methodology to calculate the probability of synchronization of the generating resources of the system, since the availability of a unit for supporting load does not guarantee that it is synchronized with the system, and this is another major contribution of this paper. We have used wind farms as illustrative examples of RERs in this work, but the proposed methodology can be extended to grid-connected solar as well. Wind farms are modeled as multi-state units and the

variability in wind power output due to both variation in wind speed and forced outages of wind turbines are considered.

Hence, we can summarize the contributions of this work as follows.

- 1) An *analytical* approach is developed for sizing of ESS to provide inertial support. This analytical approach potentially paves the way for solving more complicated problems related to the frequency stability of the grid with less computational burden and complexity.
- 2) This proposed analytical approach brings together in its framework the two most common causes of reduced inertia in the system: generator outages and replacement of conventional synchronous generators with RERs.
- 3) A new method is also developed within the proposed framework to calculate the probability of synchronization of the generating resources of the power system, which is necessary to estimate the probability distribution of system inertia.

The rest of the paper is organized as follows. The methodology proposed for determining the probability distribution of the system inertia is described in Section II. The modeling of wind farms as multi-state units is discussed in Section III. A maximum frequency deviation limit derived from a generalized LFC model is presented in Section IV. Section V demonstrates some case studies and results while Section VI provides some concluding remarks.

II. PROBABILITY DISTRIBUTION OF SYSTEM INERTIA

The expected inertia of the generating resources can be used as a reference point for estimating the size of ESS required to maintain the frequency stability of the system. The total inertia of the system varies with time due to the outage of generators and the replacement of conventional units with RERs. Hence, to calculate the expected inertia, it is necessary to first construct the probability distribution of the equivalent inertia present in the system. In this work, the conventional units are modeled as two-state units by using their forced outage rates (FORs), while RERs illustrated by wind farms are modeled as multi-state units for determining the probabilities of their outage states. It should, however, be noted that knowledge regarding the availability of generators is not sufficient for determining the probability distribution of system inertia. This is because the availability of a generator for supporting load does not guarantee that it is synchronized with the system. It simply means that it is available for synchronization when called upon. However, a generator must already be synchronized with the system in order to provide inertial support when there is an imbalance between demand and generation.

A. Probability of Synchronization

The probability of synchronization of the units can be determined by first calculating the expected energy produced by a unit for a given time horizon, and then taking the ratio of this expected energy and the total energy capacity of the unit for the same time horizon. Therefore, the probability of unit i being

committed, p_{ci} , can be expressed as follows.

$$p_{ci} = \frac{E_i^G}{G_i \times T} \quad (1)$$

where G_i is the generation capacity of unit i , and the expected energy produced by the unit for a time period T is E_i^G .

The expected energy produced by a unit can be calculated by using a production cost model as proposed in [19]. First, the equivalent load of the system, which comprises both the actual load and the capacity on outage, is expressed in terms of a random number L_e as follows.

$$L_e = L + X \quad (2)$$

where L and X are random numbers representing the total system load and the total generation capacity on outage, respectively. The probability distribution of the equivalent load, $P(L_e)$, can be obtained by the convolution of the probability distributions of the components of L_e .

The probability distribution for the system load, L , can be derived from the hourly load data. The load model is developed by scanning the hourly load data of the system over the period of interest. The cumulative probability of a load state L_i , $P_L(L_i)$ is given as:

$$P_L(L_i) = P\{L \geq L_i\} \quad (3)$$

where

$$P\{L \geq L_i\} = \frac{\text{number of hours } L \geq L_i}{\text{number of hours in interval}} \quad (4)$$

The probability distribution for the capacity on outage, X , can be derived as a capacity outage probability table (COPT) [20]. In general, when adding a new two-state unit (with states *up* and *down*) of capacity C , forced outage rate q , the cumulative probability of an outage state X can be determined by the following expression.

$$P(X) = \bar{P}(X)(1 - q) + \bar{P}(X - C)q \quad (5)$$

where $\bar{P}(X)$ is the cumulative probability of outage state X before the addition of the new unit. Equation (5) is initialized as follows (as described in [20]):

$$P(X) = \begin{cases} 1, & \text{if } X = 0 \\ 0, & \text{if } X > 0 \end{cases} \quad (6)$$

In case of multi-state units, like wind farms, (5) should be modified as follows.

$$P(X) = \sum_{i=1}^n p_i \times \bar{P}(X - C_i) \quad (7)$$

where p_i is the probability of state i of a unit with n states. The above convolution is performed with the assumption that the outages of the conventional units and the output states of the wind farms are independent. This assumption is valid and realistic since the conventional units of the system are different entities from the wind turbines that constitute the wind farms, and the availability of the conventional units is in no way affected by the wind speed or the availability of wind farms and vice-versa.

Next, in order to determine the expected energy of the generator units, it is necessary to successively deconvolve the probability distribution of each unit from the distribution of the equivalent load [21], [22]. This can be accomplished by rewriting (5) as a deconvolution formula as follows.

$$\bar{P}(X) = \frac{P(X) - q\bar{P}(X - C)}{(1 - q)} \quad (8)$$

One advantage of this method is that the addition or removal of units from the distributions may be obtained by operating directly on the convolved distribution of $P(L_e)$, which leads to a significant reduction of computation times [19].

This deconvolution process is implemented in this study as follows. Let there be N generating units in the system, the total installed capacity be G_N and let the probability distribution of the equivalent load be defined as $P_N(L_e)$ when all units are considered. Now, let us consider that the unit with the highest generating cost is removed from the system. The installed capacity is reduced to G_{N-1} and the corresponding probability distribution of the equivalent load becomes $P_{N-1}(L_e)$. The expected value of the energy generated by the removed plant, E_N^G , can then be expressed as follows [19].

$$E_N^G = T \int_{P_{N-1}}^{P_N} p_N P_{N-1}(L_e) d(L_e) \quad (9)$$

where p_N denotes the availability of the removed generator and T is the time period of interest. Thus, by successively removing generator units in decreasing order of their generating costs, the expected energy produced by all the units in the system can be determined. This information can then be combined with (1) to determine the probability of each unit being committed.

B. Expectation of System Inertia

The probability distribution, and hence the expected value of the system inertia can now be determined from the probability of commitment of each unit as derived in the previous section. Let H_r be a random variable representing the system inertia. It should be noted that H_r is a discrete random variable since it only assumes values that are equal to the sum of inertia constants of some or all units. Let U be the set of generators synchronized with the system and D be the set of generators not synchronized to the system. The probability mass function of the random variable H_r can be then represented as follows.

$$P\{H_r = h\} = \prod_{\substack{i \in U \\ j \in D}} p_{ci} q_{cj} \quad (10)$$

where p_{ci} is the probability of commitment of the i^{th} generator, $q_{cj} = 1 - p_{cj}$, and h is expressed as follows.

$$h = \frac{\sum_{i \in U} H_i S_i}{S_{eq}} \quad (11)$$

Then, the expectation of H_r can be calculated as:

$$E[H_r] = \sum_{h \in H_r} h P\{H_r = h\} \quad (12)$$

This value of $E[H_r]$ is used to determine the required size of the ESS.

C. Probability of Synchronization of Wind Farms

Although wind farms are unable to provide any mechanical inertial support due to their connection with the grid via power electronic devices, some amount of virtual inertia might still be extracted by using certain control techniques. However, since wind farms are not generally dispatched in the order of their generating costs like conventional units, the deconvolution method described in Section II-A cannot be employed to calculate the probability of synchronization of wind farms. Instead, the capacity value of wind farms can be used for calculating their probability of synchronization. In this context, consider the following postulate.

Postulate: The probability of synchronization of a wind farm (p_{cw}) is equal to its capacity value (CV_w), or,

$$p_{cw} = CV_w \quad (13)$$

Proof: Capacity value can be defined as the amount of additional load that can be served due to the addition of a unit while maintaining the existing level of reliability [23]. Let P_w be the additional load that can be supported due to the addition of a wind farm of nameplate capacity G_w . If the new wind farm supports this load for T units of time, then the energy absorbed by the load from the wind farm is given as:

$$E_w = P_w \times T \quad (14)$$

The CV of the wind farm can then be mathematically expressed as follows.

$$CV_w = \frac{E_w}{G_w \times T} \quad (15)$$

Comparing (15) with (1), we see that just like CV, the probability of synchronization also represents the amount of energy that the system absorbs from a unit for serving load. Thus, it can be concluded that in the context of this work, the probability of synchronization of a wind farm is essentially equal to its CV.

The validity of this equivalence is also supported using Monte Carlo simulation, which makes no assumptions regarding the probability of synchronization and the CV of a wind farm, but still produces results very close to those obtained using the analytical method.

III. MODELING OF WIND FARMS

Wind farms are modeled as multi-state units in this work. The variability in wind power output due to both variation in wind speed and forced outages of turbines are considered.

A. Modeling of Wind Speed

Wind speed can be approximated by a discrete Markov chain with a finite number of states. The probability, frequency, and transition rate of each wind state can be estimated from a large number of samples of wind speed time-series data. The

probability of each wind state is determined as follows [24].

$$p_{ws,i} = \frac{\sum_{j=1}^N n_{ij}}{\sum_{k=1}^N \sum_{j=1}^N n_{kj}} \quad (16)$$

where $p_{ws,i}$ is the probability of wind being in state i , n_{ij} is the number of transitions from state i to state j , and N is the total number of states. These wind speed states can be easily converted to wind power output states by utilizing the power curve of a wind turbine [25].

B. Modeling of Wind Farm Capacity Outage

Wind farms generally comprise of several wind turbines, where the wind turbines can be modeled as two-state units (*up* and *down*) with known failure and repair rates λ and μ respectively, similar to conventional units. Hence, a COPT can be built for a wind farm, say $COPT_w$, considering the forced outage rate of the wind turbines, by using (5). $COPT_w$ is then combined with the wind power states earlier obtained in Section III-A to construct the multi-state unit of the wind farm, as described in [4]. The multi-state wind farm unit thus developed can then be added to the COPT of the system by using (7).

IV. FREQUENCY STABILITY OF POWER GRID

The control of frequency and power generation is commonly referred to as load frequency control (LFC). It consists of the following stages: inertial response, primary frequency response (PFR), secondary frequency response (also known as automatic generation control or AGC), and tertiary frequency response [26]. This paper focuses on the inertial response of the grid. The following sections describe how the frequency dynamics are affected by the equivalent inertia of the system and the generalized LFC model used to calculate the minimum inertia required by the system to maintain frequency stability.

A. Modeling of Grid Frequency Response

Frequency response plays a vital role in overall system dynamic performance. An imbalance in real power leads to frequency deviation from the nominal values and might result in load shedding. The swing equation is traditionally used to represent the frequency dynamics of the system and can be expressed as follows [27].

$$\frac{2H}{f_s} \frac{df}{dt} = \frac{P_m - P_e}{S} = \frac{\Delta P}{S} \quad (17)$$

where H is the equivalent inertia, f_s is the nominal frequency, $\frac{df}{dt}$ is the RoCoF, P_m and P_e are the mechanical power input and the electrical power output, and S the nominal rating of the system, respectively.

B. Load Frequency Control Model

A generalized LFC model is utilized in this study [28], which is capable of representing the contribution of each governor to the system frequency control. The model of LFC for a multi-machine system is illustrated in Fig. 1.

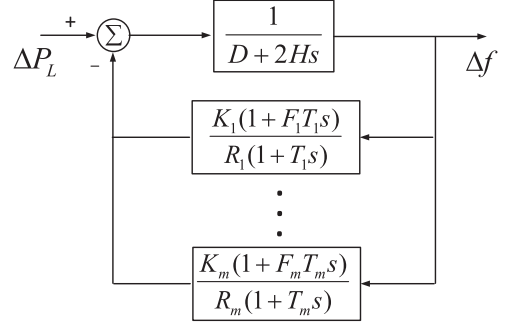


Fig. 1. LFC model of a multi-machine system [28].

The governor time constants of all machines are assumed to be of equal value since the maximum frequency deviation has a low sensitivity to this quantity (T_R) [28].

C. Minimum Inertia Required

The minimum inertia required by the system to maintain frequency stability in the event of a disturbance is discussed in this section. The equation for frequency deviation can be developed from the LFC model of multi-machine system [29] and is shown in (18).

$$\Delta f(s) = \frac{\frac{\Delta P_L}{s}}{D + 2Hs + \sum_{i=1}^m \frac{K_i(1 + F_iT_{Ri}s)}{R_i(1 + T_{Ri}s)}} \quad (18)$$

Assuming all values of T_R to be identical and using inverse Laplace transformation, the expression for frequency deviation in the time domain is obtained as follows.

$$\begin{aligned} \Delta f(t) = & \frac{\Delta P_L}{2HT_R\omega_n^2} \\ & \times \left(1 - \frac{1}{\sqrt{1 - \zeta^2}} e^{-\zeta\omega_n t} \cos(\omega_n \sqrt{1 - \zeta^2} t - \phi) \right) \\ & + \frac{\Delta P_L}{2H\omega_n \sqrt{1 - \zeta^2}} e^{-\zeta\omega_n t} \sin(\omega_n \sqrt{1 - \zeta^2} t) \end{aligned} \quad (19)$$

where

$$F_R = \sum_{i=1}^m \frac{K_i F_i}{R_i} \quad (20)$$

$$R_R = \sum_{i=1}^m \frac{K_i}{R_i} \quad (21)$$

$$\omega_n = \sqrt{\frac{1}{2HT_R}(D + R_R)} \quad (22)$$

$$\zeta = \frac{1}{2} \frac{2H + T_R(D + F_R)}{\sqrt{2HT_R}(D + R_R)} \quad (23)$$

$$\phi = \tan^{-1} \left(\frac{\zeta}{\sqrt{1 - \zeta^2}} \right) \quad (24)$$

The maximum frequency deviation is obtained by equating the derivative of $\Delta f(t)$ in (19) to zero and is expressed as follows.

$$\Delta f_{\max} = \frac{\Delta P_L}{R_R + D} \left(1 + e^{-\zeta \omega_n t_{\max}} \sqrt{\frac{T_R(R_R - F_R)}{2H}} \right) \quad (25)$$

where

$$t_{\max} = \frac{1}{\omega_n \sqrt{1 - \zeta^2}} \tan^{-1} \left(\frac{\omega_n \sqrt{1 - \zeta^2}}{\zeta \omega_n - 1/T_R} \right) \quad (26)$$

D. Minimum Inertia Required in a Wind-Integrated System

The total inertia of the system is reduced when conventional generators with high rotating masses are replaced by wind generators with low inertia. This reduction of inertia is modeled into the maximum frequency deviation limit as follows [30]. It is assumed that the reduction in the system inertia due to the removal of a conventional unit is γ_{cv} and the contribution from the wind turbines is γ_w . Then, the new values of system inertia and the equivalent regulation constant can be expressed as follows.

$$H_{\text{new}} = H_{\text{old}}(1 - \gamma_{cv} + \gamma_w) = \gamma H_{\text{old}} \quad (27)$$

$$R_{\text{new}} = \frac{R_{\text{old}}}{(1 - \gamma_{cv} + \gamma_w)} = \frac{R_{\text{old}}}{\gamma} \quad (28)$$

This change in system inertia is also incorporated into the other governor parameters. The old values are replaced by the new values in (25) to determine the value of the maximum frequency deviation in a wind-integrated system. The minimum inertia required to maintain frequency stability can now be determined from the above equations by using a pre-determined value of $\Delta f_{\max}$. For example, for a system operating with a nominal frequency of 60 Hz, $\Delta f_{\max}$ can be set at 0.1 Hz. The above model can be used to simulate system response for load disturbances as well as generator or other equipment failures.

E. Contribution of ESS Towards Frequency Stability

Let the minimum inertia level that is required to maintain frequency stability be $H_{\min}$ for a particular disturbance event. Also, let the equivalent inertia of a system be $H_{\text{sys}}(t)$ at any time t . If $H_{\text{sys}}(t) < H_{\min}$, then an ESS may be deployed, which can inject active power into the system at a sufficiently high rate to maintain frequency stability. Hence, the inertia that the ESS needs to provide for a particular disturbance at any time t , if $H_{\text{sys}}(t) < H_{\min}$, can be defined as follows.

$$H_{\text{ESS}}(t) = H_{\min} - H_{\text{sys}}(t) \quad (29)$$

The ESS is sized based on the expected value of the system inertia, $E[H_{\text{ESS}}(t)]$ or H_{ESS} , which is calculated as follows.

$$H_{\text{ESS}} = H_{\min} - E[H_{\text{sys}}(t)] \quad (30)$$

where $H_{\min}$ is constant for a particular disturbance event and $E[H_{\text{sys}}(t)]$ is determined by the method proposed in Section II-B.

Now, the relationship between H_{ESS} , and the real power required to be injected by the ESS for maintaining frequency

stability, P_{ESS} , can be derived from (17) as follows [15].

$$H_{\text{ESS}} = P_{\text{ESS}} \frac{f_s}{2} \left(\frac{df}{dt} \right)^{-1} \quad (31)$$

In (31), the expression $\frac{df}{dt}$ or the RoCoF can be defined as a measure of how quickly the frequency changes following a sudden imbalance between generation and load [31] and is most commonly expressed in Hz per second. The initial RoCoF is calculated as the change in frequency over a 0.5 s time period immediately following a sudden generation loss [32]. The initial RoCoF depends on several factors including the magnitude of the disturbance event, the amount of system inertia online, and the speed and magnitude of the frequency response. If the initial RoCoF is significantly high, then the system frequency may fall at a level where underfrequency load shedding (UFLS) may be required, the UFLS requirements for the North American grid being provided in [33]. Therefore, the RoCoF should be restricted within a certain value to avoid UFLS. According to [15], the value of RoCoF should not exceed 0.5 Hz/s. In this paper, the value of RoCoF is assumed to be a constant value of 0.5 Hz/s, thus considering the worst-case scenario.

Fig. 2 summarizes the analytical approach proposed in this work.

V. CASE STUDIES AND RESULTS

Data from the New England IEEE 39-bus system [34] is used to test the efficacy of the proposed method. The test system is illustrated with the help of a single line diagram in Fig. 3, and it comprises 39 buses, 10 generators, and 46 transmission lines. Part of the conventional generation is replaced by wind farms in some of the case studies presented in this work, to illustrate the effect of RER integration on system inertia. Wind speed data from [35] is used to model wind farms as multi-state units, as described in Section III. The CV of the wind farm is calculated in terms of the probability of synchronization to be 0.15 for the data-set used in this work. The annual hourly load curve is obtained from [36] and adjusted according to the peak load of the test system. Data for the governor parameters are obtained from [28] and reliability data for the generating units are obtained from [37].

A. Probability of Synchronization

The probability distribution of the equivalent load of the system, L_e , is illustrated in Fig. 4, which also shows how the distribution of the equivalent load changes as units are gradually removed from the system using deconvolution. When all units have been removed, the distribution of the equivalent load coincides with the load duration curve. The probability of synchronization for each unit is calculated using the method described in Section II, and the results are shown in Table I. These results can be utilized to determine the probability distribution of system inertia and its expected value. The probability distribution of the system inertia is shown in Fig. 5. The random variable representing the system inertia, H_r , ranges from 0 to 792.7, and the expected value of the system inertia, $E[H_r]$ is

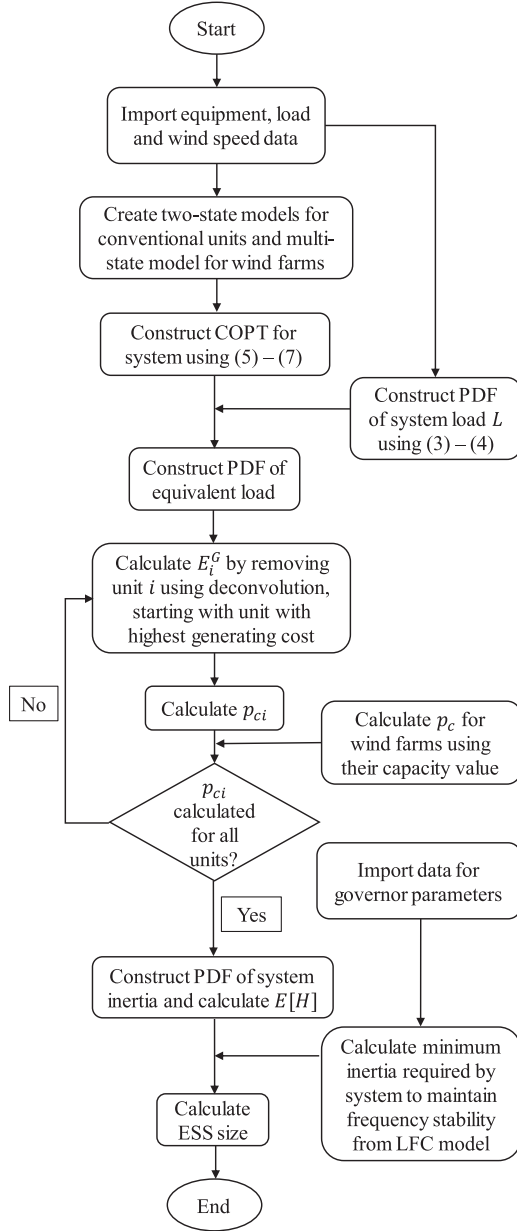


Fig. 2. Flowchart summarizing the analytical approach proposed in this work.

TABLE I
EXPECTED ENERGY OUTPUT FOR ONE YEAR

Unit No.	Expected Energy per year (MWh)	p_c
1	8,298,663	0.911
2	602,674	0.106
3	4,394,496	0.692
4	1,365,113	0.239
5	19,889	0.005
6	2,744,060	0.456
7	170,530	0.034
8	69,397	0.014
9	7,014,167	0.926
10	9,102,311	0.945

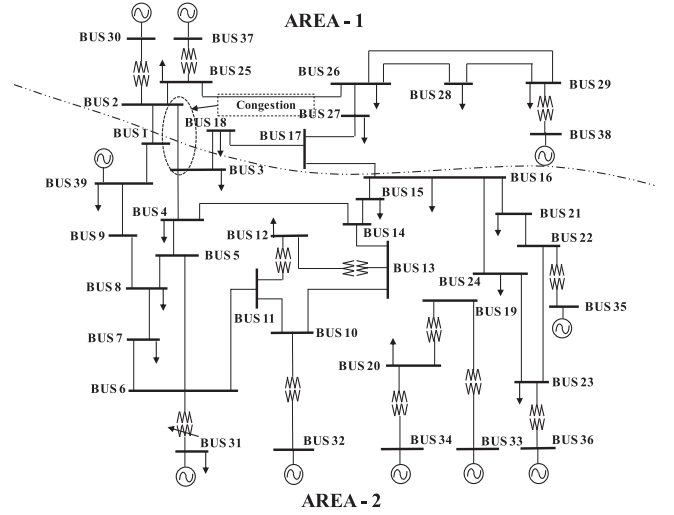


Fig. 3. Single line diagram of the IEEE 39 bus system.

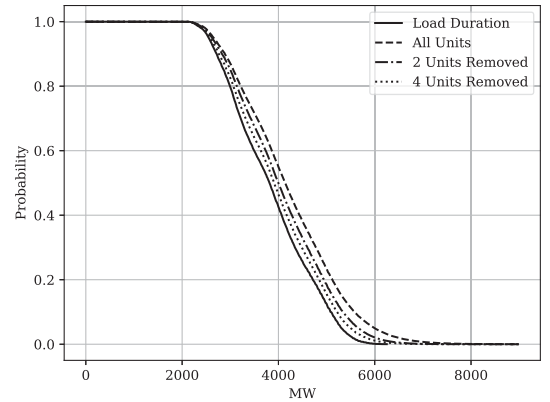


Fig. 4. Probability distribution of equivalent load and the load duration curve for the IEEE 39 bus system.

calculated to be 581.62 s for the original test system without any wind power penetration.

B. Case Studies

The ESS sizing approach proposed in this work is illustrated with the help of three cases, by varying the degree of wind penetration in each case. Disturbance in the form of a load of 0.1 p.u. is assumed to change the system frequency from its nominal value of 60 Hz. ESS sizes for three values of maximum frequency deviation ($\Delta f_{\max}$) are determined for each case. In general, the proposed approach can be used to size ESS devices for any value of maximum frequency deviation and any load disturbance. This provides the system operator with ample flexibility in choosing the parameters. Data for the inertia constant of wind farms are obtained from [30].

- 1) *Case 1:* The original system with only conventional generation is considered in this case.
- 2) *Case 2:* About 8% of the generation capacity of the system (the current share of installed wind capacity in the U.S.

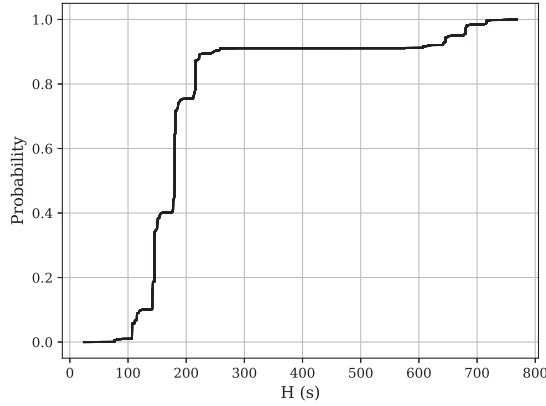
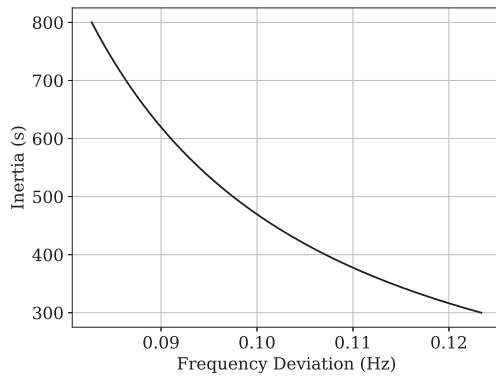
Fig. 5. Cumulative Distribution Function of H .

Fig. 6. Maximum frequency deviation vs. inertia for the IEEE 39 bus system for a load disturbance of 0.1 p.u.

today) is replaced by wind generation. To achieve this, a conventional unit of 580 MW is removed from the system and replaced by a wind farm of capacity of 640 MW. This wind farm is assumed to consist of 80 identical wind turbines, of 8 MW each.

- 3) *Case 3*: About 20% of the generation capacity of the system (target wind power share in the U.S by 2030 [38]) is replaced by a wind farm of capacity 1520 MW. Two conventional units with capacities of 646 MW and 865 MW are removed to achieve this.

C. Frequency Deviation Limit

The minimum inertia required by the system to maintain frequency stability under a load disturbance is calculated from (25), (27), and (28). Fig. 6 illustrates how the maximum frequency deviation of the system increases with decreasing system inertia for a load disturbance of 0.1 p.u. In this work, the size of the ESS is determined based on the difference between the expected value of the system equivalent inertia and the minimum inertia required to maintain frequency stability. However, since the proposed approach involves the construction of the entire probability distribution of system inertia, other statistics besides the mean value can be easily extracted from the distribution. This provides the system planner with the flexibility to evaluate

TABLE II
ESS SIZES FOR A LOAD DISTURBANCE OF 0.1 P.U.

Case	Freq. Dev. Limit (Hz)	$E[H_r]$ (s)	$H_{\min}$ (s)	H_{ESS} (s)	P_{ESS} (MW)
1	0.085		734	152	253
	0.09	582	619	39	62
	0.095		531	N/A	N/A
2	0.085		787	219	365
	0.09	568	659	91	152
	0.095		557	N/A	N/A
3	0.085		875	315	525
	0.09	560	728	168	280
	0.095		608	48	80

the risk of losing frequency stability associated with installing different sizes of ESS.

D. ESS Size

Results for the three cases are shown in Table II. The energy capacity of the ESS would depend upon several factors, including how frequently it is called upon by the RTO to provide synthetic inertia, the system behavior, and also the charge-discharge characteristics of the ESS. If the ESS facility is designed to provide other services in addition to synthetic inertia, these services will also be considered in determining the energy capacity. Although the location of the ESS is not explicitly determined in this work, given that it is the wind farm that displaces system inertia, the ESS should be located near the wind farm for providing virtual inertia support. In case there are multiple RERs, the total ESS capacity required can be distributed proportionately among all locations containing the RERs.

Results show that for the first two cases, an ESS is only required when the maximum frequency deviation of the system has to be restricted to 0.09 Hz. The system in both cases possesses adequate inertia to limit the frequency deviation beyond 0.09 Hz. For case 3, however, since the wind penetration is significantly higher than case 2, an ESS is required to limit the maximum frequency deviation up to 0.095 Hz. This also implies that as the penetration of RERs keeps on increasing, larger ESSs will be required in the future for restricting system frequency deviations. Results obtained by employing the analytical approach are then validated using Monte Carlo simulation (MCS). Using MCS, the mean inertia of the system for cases 1, 2, and 3 are calculated to be 595 s, 587 s, and 569 s, respectively. Comparing these results with those presented in Table II, we can see that the mean inertia obtained by both methodologies lies within approximately 3% of each other for each case. This validation proves the efficacy of the proposed analytical approach and emphasizes its utility in sizing of ESS for grid frequency stability without having to bear the high computational burden of simulation methodologies.

E. Effect of Incorporating Transmission Constraints

The results of the proposed analytical approach in estimating the system inertia are compared with the results of a simulation technique that considers the transmission constraints of the system. Case 2 is used for the purpose of this comparison. For this case, the mean inertia of the system considering the

transmission constraints is calculated to be 639 s, which is significantly higher than 568 s, the result obtained using the analytical method. The reason for this mismatch is investigated and congestion is identified in the transmission line between buses 2 and 3. The system is then split into two equivalent areas, as shown in Fig. 3, to avoid this congestion. The expected inertia values for areas 1 and 2 are then calculated using the analytical approach to be 528 s and 96 s, respectively. The expected inertia values of the individual areas add up to 624 s, which is within 2% of the value obtained using MCS. This shows that the proposed analytical approach is valid for multi-area systems even when the transmission constraints are considered. Also, system operators typically have knowledge regarding the areas of congestion in the system. Therefore, they can use the proposed analytical method to perform back-of-the-envelope calculations to allocate the necessary amounts of storage required by each zone to provide inertial support. This further emphasizes the efficacy of the proposed approach, since a practical power system generally comprises multiple areas controlled by different balancing authorities.

VI. CONCLUSION

This paper proposes a novel analytical method for sizing of ESS for providing grid inertial support in presence of RERs. The proposed approach is based on estimating the expected inertia of the system, consisting of conventional generators and RERs. It involves the construction of the probability distribution of system inertia, taking into account generator outages and the replacement of conventional units with RERs. The reduction of system inertia due to various degrees of RER penetration and the sizes of ESS required are calculated and illustrated using a few case studies. The results obtained using the proposed analytical approach are validated using Monte Carlo simulation and the efficacy of this approach is demonstrated for multi-area systems when transmission constraints are considered. This approach also offers system planners flexibility regarding the choice of certain system parameters and the option of risk assessment for different ESS sizes. Future work involves the integration of this approach into an optimal ESS planning framework, that would also allow the economic assessment of ensuring frequency stability of the grid using ESS.

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