INL/CON-21-65230-Revision-0

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October 2022

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Prepared for the
U.S. Department of Energy
Under DOE Idaho Operations Office
Contract DE-AC07-05ID14517, DE-AC07-05ID14517

An Operational Resilience Metric to Evaluate Inertia and Inverter-based Generation on the Grid

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***Abstract*—In an effort to reduce carbon emissions there has been considerable effort to increase the penetration of inverter-based renewable energy sources. The adoption of renewable generation over conventional inertia-based generation sources is forming considerable challenges for the operation and stability of the power system. The reduced inertia in power systems has resulted in a grid where frequency changes occur more rapid after a disturbance. Because of this, it is important to understand the stability of the system and the size of disturbance it is capable of withstanding.**

Therefore, this paper presents a resilience metric that evaluates the maximum size of disturbance a systems can withstand based on the system inertia and the primary frequency control of inverter and inertia-based generation. The results are shown visually and are based on the real-time operation of generation units and their characteristics such as latency, ramp rates, and energy constraints. It is demonstrated that the real-time output of the generating units has an effect on the size of disturbance that a system can withstand. It is expected that this type of analysis can help operators increase the resilience of power systems in the future.

***Index Terms*—Power System Resilience, Power System Stability, Power System Inertia, Primary Frequency Control**

I. Introduction

Over the past several decades the construction of new power generation has seen a considerable increase in the number of inverter-based units, such as wind, solar, and battery energy storage. The integration of inverter-based generation sources has been largely motivated by the increasing frequency of extreme weather events due to climate change. Therefore, in an effort to curb carbon emissions and preserve the environment, many nations have put forth targets of renewable energy generation. In the U.S., most states have renewable portfolio standards or policies that require or encourage electricity suppliers to provide a minimum share of electricity from renewable resources [1].

Traditionally, power generation units consisted of large synchronous spinning machines to generate power. In this design, the generation units contribute spinning kinetic energy to the system, known as inertia. In addition, because of economic reasons these generation units are typically ran at their maximum efficiency point which is below their maximum output [2]. Therefore, they have the ability to generate more power when needed, known as reserve power.

In contrast, inverter-based renewable generation units do not provide inertia to the system. Even wind generation, which has a large rotating mass does not directly contribute inertia due to their inverter-based connection with the grid [3]. Furthermore, their optimal economic output is at peak generation. Therefore, these assets are typically ran at their maximum output and therefore do not have reserve power.

The shift from inertia-based to inverter-based generation has resulted in a system with a reduced amount of inertia and reserve power. With reduced inertia, power system face rapid frequency changes when generation and demand are not balanced. When large disturbances occur, primary frequency control may not have the necessary time to respond and ramp generation to balance the system. When this occurs, the system frequency can fall below a predefined level, and part of the customer load must be disconnected for protection, referred to as under frequency load shedding (UFLS). Fig. 1 demonstrates a disturbance event on the grid.

The paradigm shift from inertia to inverter-based generation has presented researchers with several new technical challenges. One of the most important of them is the frequency stability and is the focus of this paper. In this regard, we develop a resilience metric for power systems based on their inertia and the primary frequency control of generation assets. The metric is based on inertia of the system and the aggregation of assets flexibility in real power from their real-time operating output. The metric also considers temporal characteristics such as latency, ramp-rates, and energy constraints. The result is a visual display to indicate to an operator the size of a disturbance the system can withstand without UFLS or an over frequency generator trip (OFGT) event.

The rest of this paper is formatted as follows: Section 2 introduces the concept of resilience in power systems. Section 3 gives a background on the stability of the power system and the rate of change of frequency during a disturbance. Section 4 covers the needed background for the resilience metric including inertia of the power system and flexibility of primary frequency control. A case study is presented in Section 5 and concluding remarks and future work is given in Section 6.

This manuscript has been authored in part by Battelle Energy Alliance, LLC under Contract No. DE-AC07-05ID14517 with the U.S. Department of Energy. Work supported through the U.S. Department of Energy's Grid Modernization Initiate.

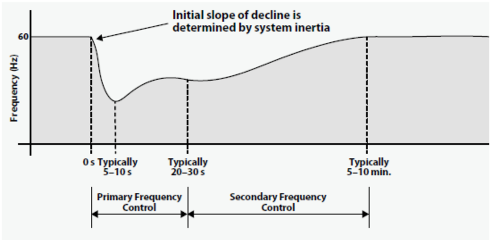

Fig. 1. When a disturbance occurs, the frequency of the system deviates from is nominal level. The frequency is stabilized and returned to is nominal level through primary and secondary frequency control [4].

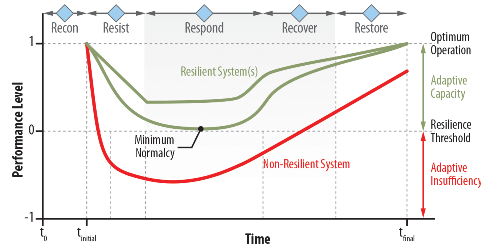

Fig. 2. The Disturbance and Impact Resilience curve showing the "R's" of resilience. Image taken from [12]

II. Resilience of the Power System

The concept of resilience in engineering systems was first introduced in [5]. Today, many definitions exist from the academic community [6], policy directives [7], and from well respected organizations [8], [9]. Although they have different definitions, they all share a general commonality. That is resilience is the ability to anticipate, adapt, and restore to disturbances. This concept is captured in the Disturbance and Impact Resilience Evaluation (DIRE) curve shown in Fig. 2. Here, the resilience can be broken down into what is known as the five "R's" of resilience; recon, resist, respond, recover, and restore.

It can be seen that resilience is not a short-term or long-term property of a system. It encompasses time prior to a disturbance through its return to normalcy. Rieger [10] presented the idea of the resilience threshold, or maximum acceptable level of degradation of a system. There are numerous metrics that can be used here, for example, demand not served, maximum number of customers out of service, or critical loads not served. These metrics do a relatively good job at describing the power system resilience based on the definition. However, these metrics look back in time at the result of a disturbance, therefore, not giving an operator a useful perspective of the current state of their system. To this end, resilience metrics have been defined in [11] based on the aggregation of assets adaptive capacity in terms of real and reactive power to give an operational perspective in which operators can use to determine the size and duration of future disturbances the system can withstand. The metrics were further developed for hydropower assets in [12] and solar with forecast uncertainty in [13]. However, to date these metrics have not consider the resist phase of the DIRE curve. Therefore, the goal of the resilience metric proposed in this paper presents a metric to evaluate the resist phase of the DIRE curve based on the system inertia and primary frequency response.

III. Stability of the Power System

In the U.S. power system the frequency is at a constant oscillation of 60 hertz (Hz). The stability of the power system can therefore be defined as the ability to keep the voltage and frequency levels within certain bounds from their desired level. Deviation of the voltage and frequency occur when there is an imbalance between power generation and load demand. Voltage is in relation to reactive power and frequency is in relation to the balance of real power. In this work, we are concerned with the stability of the power system frequency and use of the term power is referring to real power.

When the power generation and load are not balanced the system frequency will change, given as

$$\frac{df}{dt} = \frac{f\Delta P}{2H} \tag{1}$$

where df/dt is the rate of change of frequency, ΔP is the disturbance or difference between generation and load, and H is the inertial constant. The inertial constant is given as

$$H = \frac{\frac{1}{2}J\omega^2}{S} \tag{2}$$

where J is the moment of inertia of the rotating mass, ω [rad/sec] is the angular speed of rotation, and S is the MVA rating of the generator. When generation falls short of the load demand the frequency of the system will drop. In order to protect equipment from damage system operators place limits on the minimum frequency level allowed, typically 59.5 Hz in the U.S [14]. At this point part of the customer load may be disconnected, referred to as under frequency load shedding (UFLS). The reduction in customer load helps balance the generation and load and mitigate further dropping in frequency. The other scenario is when generation exceeds the load and frequency begins to increase. Here, generation can be taken off line, referred to as over frequency generation trip (OFGT).

IV. Resilience Metric Methodology

This section covers the mathematical background of the inertia in power systems and the primary frequency control, used to define the resilience metric proposed in this paper.

A. *Inertia in the Power System*

Traditionally, power has been generated by large rotating masses. These rotating masses store large amounts of inertia or kinetic energy in the system. Due to convention of equation symbols, kinetic energy is often used instead of inertia. In industry it is common for an inertial constant of a generator to be given, as in (2). Here, the kinetic energy of the generator is the numerator term and is given as

$$K = \frac{1}{2}J\omega^2 \tag{3}$$

where ω is the rotational frequency and J is the moment of inertia. In a synchronous generator the rotational frequency is given by

$$\omega = \frac{2\pi f}{Np/2} \tag{4}$$

where f is the electrical frequency and Np is the number of poles. Thus, the kinetic energy of an asset is expressed as

$$K = \frac{1}{2}\left[\frac{2\pi f_0}{Np/2}\right]^2 J \tag{5}$$

where f_0 is the real-time frequency. The kinetic of the system with n assets can then be expressed as

$$K_0 = \frac{1}{2}\sum_{i=1}^{n}\left[\frac{2\pi f_0}{Np_i/2}\right]^2 J_i \tag{6}$$

or

$$K_0 = \sum_{i=1}^{n} H_i S_i \tag{7}$$

when the inertial constant H is known with the rated power of the generator S.

The number of poles and the moment of inertia are physical properties of the generator and therefore remain constant. Due to the conservation of energy, changes in kinetic energy directly result in changes to the frequency. Therefore, the kinetic energy at the point of UFLS where frequency is at a minimum, $f_{\min}$, and at OFGT where frequency is at the maximum, $f_{\max}$, are given as

$$K_{\min} = \frac{1}{2}\sum_{i=1}^{n}\left[\frac{2\pi f_{\min}}{Np_i/2}\right]^2 J_i \tag{8}$$

and

$$K_{\max} = \frac{1}{2}\sum_{i=1}^{n}\left[\frac{2\pi f_{\max}}{Np_i/2}\right]^2 J_i \tag{9}$$

Using the maximum and minimum kinetic energy values and the real-time frequency, the available kinetic energy in the system is given as

$$K_{\Delta_{\text{UFLS}}} = K_0 - K_{\min} \tag{10}$$

in the case of UFLS when load exceeds generation, and

$$K_{\Delta_{\text{OFGT}}} = K_{\max} - K_0 \tag{11}$$

in the case of OFGT when generation exceeds load. The available kinetic energy or inertia is used to determine the size of disturbance a system can withstand.

1) Power Disturbance Curve: Using the available kinetic energy, the amount of time, t, for an UFLS power disturbance event of size P_d to drop frequency to the minimum is therefore given as

$$t = \frac{K_{\Delta_{\text{UFLS}}}}{P_d} \tag{12}$$

and for an OFGT event, the time is given by

$$t = \frac{K_{\Delta_{\text{OFGT}}}}{P_d} \tag{13}$$

During an UFLS event, the nominal, available, and UFLS kinetic energy is shown in Fig. 3. Here, it is shown under a large, medium, or small disturbance and it can be seen that the kinetic energy available is constant and the large the disturbance the faster the kinetic energy is extracted and the quicker the frequency drops to the UFLS limit. The kinetic energy at the UFLS limit is highlighted. If we rearrange eqn. [] and express it as

$$P_d = \frac{K_{\Delta_{\text{UFLS}}}}{t}, \tag{14}$$

we can solve for the disturbance size at any give time. These points are used to plot the power disturbance curve and is shown in Fig 4. Again, the large, medium, and small disturbance points are highlighted. The power disturbance curve therefore represents the amount of time a system has based on the size of disturbance before the UFLS is reached.

B. Primary Frequency Response

Primary frequency response is triggered automatically when the frequency deviates beyond the bound set for the frequency. When this occurs, the kinetic energy of the spinning masses is increased or decreased by speeding up or down based on the load and generation out of balance. At this moment, the speed controller, or governor, of each generator acts to increase or decrease the generated power in an effort to clear the imbalance and stabilize the frequency. Conventional, inertia-based generation units are called on to supply this service.

The PFR is activated when the frequency deviates too far from the desired setpoint as shown in Fig. 1. Here, the real power output of available assets are ramped up or down automatically by governor control to stabilize the frequency of the system. The availability of assets and their characteristics such as latency, ramp rates, maximum and minimum power, energy constraints, and current operating output determine the ability of a system to react to such disturbances.

We begin by defining the flexibility of each asset as the amount of power output it can change from its current operating point. In the increasing power direction it is given as

$$P_{\Delta}^{+} = P_{\max} - P_0 \tag{15}$$

where $P_{\max}$ is the maximum output and P_0 is the current output. In the reduced power direction this is given by

$$P_{\Delta}^{-} = P_0 - P_{\min} \tag{16}$$

Next, the rate that an asset can reach these limits is considered. First there is a latency before an asset can begin to change its output. The latency can be the time delay from a sensor before a controller can respond and the time for the physical response to occur after the control command has been sent. Both of these forms of latency are considered in a single term given as λ. After the latency, the asset begins to ramp up, $P(t)^{+}$, or down, $P(t)^{-}$, at at a maximum ramp rate of dP^{+}/dt in the positive and dP^{-}/dt in the negative direction.

The PFR is calculated based on the current operating point and given in the positive direction by

$$P_0^{+}(t) = \frac{dP^{+}}{dt}(t - \lambda) \tag{17}$$

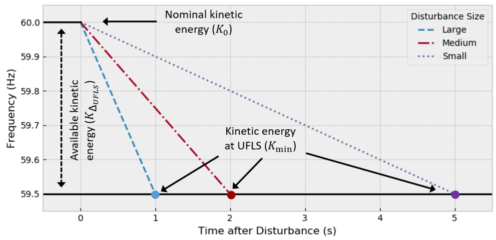

Fig. 3. The frequency response of a power system after different size disturbances. The available kinetic energy from the nominal level to UFLS is the same under all cases.

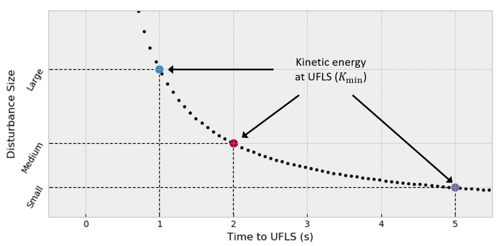

Fig. 4. The power disturbance curve represents the time to UFLS based on any size of disturbance. Here, the large, medium, and small disturbance are in relation to that shown in the previous figure.

with the limit at P_Δ^+, and in the negative direction

$$P_0^-(t) = \frac{dP^-}{dt}(t-\lambda) \tag{18}$$

with the limit at P_Δ^-. The potential PFR of an asset is shown in Fig. 5.

C. Maximum Disturbance Size

The maximum disturbance size is determined based on the power disturbance curve and the primary frequency control of the aggregated assets. This concept is shown for an UFLS event graphically in Fig. 6. The point where the power ramp curve and power disturbance curve cross is the maximum disturbance the system can withstand. It represents the point where the ramping generation is equal to that of the maximum disturbance based on the UFLS frequency. Here the generation and load are again balanced and the frequency will no longer drop.

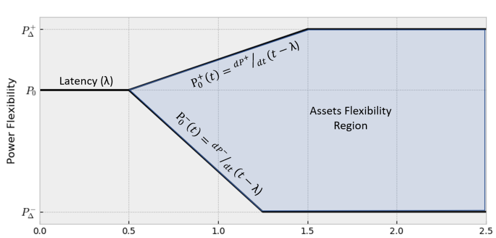

Fig. 5. The flexibility region of an asset bounded by its latency and ramping rates. The bound is the maximum an asset can contribute to PFR after a disturbance occurs.

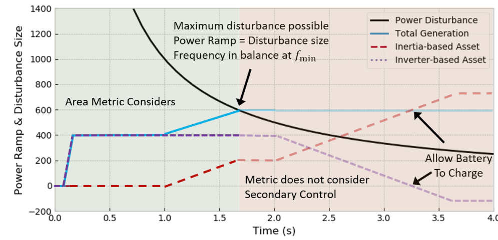

Fig. 6. Overlay of the power disturbance curve and the generation ramp curve. The resilience metric considers the primary frequency control and power disturbance curve highlighted on the left part of the plot.

TABLE I
AGGREGATION OF GENERATION SIZE AND TEMPORAL CHARACTERISTICS OF EACH.

	Latency	Ramp Up (MW/s)	Ramp Down (MW/s)
Gas-fired	1.0	1.0	1.0
Hydro	0.5	5.0	5.0
Inverter	0.1	100	100
Battery	0.1	100	100

V. Evaluation of Power System Resilience

In this section we evaluate and demonstrate the resilience of a power systems with inertia and inverter generation assets including battery storage.

A. System Inputs

To evaluate the power system resilience the following is needed: system total inertia, frequency, frequency limits, maximum generation capacity, real-time generation, and temporal characteristics. The generation assets are groups into gas-fired, hydro, inverter-based, and battery storage. The maximum power output, the real-time power output, latency, ramp up and ramp down rates are defined for each group. The battery storage also includes the minimum output, as it can be negative when in the charging state.

B. Case Study

To demonstrate the resilience metric proposed in this work, we evaluate a power system with gas-fired, hydro, inverter (solar, wind, etc.), and battery storage. At current state, the assets are grouped instead of input individually as they typically have similar characteristics such as latency and ramp rates, and are given in Table I. It is assumed that all the inertia-based generation units are 10 MW and the inertia constant for each of them is 5 [15]. Four scenarios are considered, and they all have the same load demand of 92 MW.

The first scenario can be considered a baseline case, consisting of only conventional inertia-based generation. The maximum amount of gas-fired and hydro generation is 100 and 20 MW, respectively. The hydro generation is ran at maximum capacity and the gas-fired generation contributes the additional 72 MW of generation. This results in a total system inertia of 420 MWs. The results of the flexibility of the assets, the power

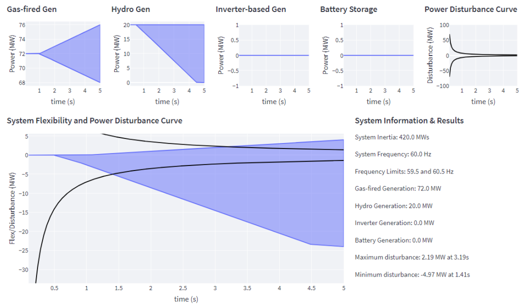

Fig. 7. Flexibility of the generation assets, the power disturbance curve, and the system flexibility for scenario I.

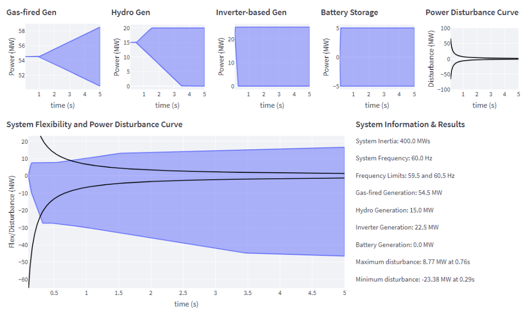

Fig. 8. Flexibility of the generation assets, the power disturbance curve, and the system flexibility for scenario IV.

disturbance curve, and the system flexibility for this scenario is shown in Fig. 7. Under these conditions, the system is capable of absorbing a maximum disturbance of 2.19 MW.

The second scenario considers the addition of 25 MW of inverter-based generation. In this scenario, the inverter-based generation is contributing its maximum output of 25 MW, the hydro contributes 20 MW, and the gas-fired contributes the additional 47 MW of generation. In this state the system has a reduced total inertia of 350 MWs. The system under these conditions is capable of absorbing a maximum disturbance of 1.96 MW.

The third scenario considers the inverter-based generation with an output 10% below its maximum output, therefore, being able to contribute to primary frequency control. In this scenario, there is 54.5 MW gas-fired generation, the hydro generation is reduced to 15 MW but still has a maximum capacity of 20 MW, and there is 22.5 MW of inverter-based generation. The total inertia of the system is 400 MWs. Here, the system with these outputs is capable of withstanding a maximum disturbance of 5.82 MW.

The last scenario is the same as scenario III but includes the addition of 5 MW of battery storage. Again the total inertia of the system is 400 MWs and the results are shown in Fig. 8. The system is capable of absorbing a maximum disturbance of 8.77 MW.

VI. Conclusion and Future Work

This paper has presented a resilience metric that is based on the primary frequency control of aggregated assets and the systems total inertia. The metric provides the maximum disturbance size the system can arrest, right at the frequency limit, in an under frequency or over frequency disturbance event. It was demonstrated that meeting the load demand using different generation sources has an effect on the disturbance size the system can withstand.

Future work includes having inputs for each individual asset instead of groupings. This will allow different temporal characteristics such as ramp rates for each asset. Furthermore, the inertia of the individual assets can be used. In addition, the power disturbance curve is based on a power disturbance (ΔP in eqn. 1) that is constant. For a higher fidelity result, the disturbance should reflect the difference between the disturbance size and the primary frequency control change in generation, i.e. as the power is ramped up the rate of change of the frequency is reduced. However, the current state of the models presented in this work should therefore be considered conservative. Lastly, the metric will be validated with a Simulink or PowerWorld model.

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