Considerations in the Initialization of Power Flow Solutions from Dynamic Simulation Snapshots

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***Abstract* — This paper looks at the decision-making involved with taking any snapshot from a dynamic simulation, and re-initializing the power flow from that snapshot. This is particularly important in educational and training contexts, which gives students and engineers the ability to make informed decisions when handling contingencies. A motivating example is provided, followed by an analysis of the most important models to consider when re-initializing a power flow. The analysis is supplemented by computational examples with regards to the models.**

***Keywords*— power flow, power system dynamics, power system simulation, visualization, power system education**

I. Introduction

Two of the most common electric grid analysis techniques are power flow and time-domain simulations. The Power flow, which was first presented in digital form in [1] and [2], is used to solve the quasi-steady power balance equations to determine the per-unit voltage magnitude and angle at every bus in an electric grid. Hence it can be thought of as determining an equilibrium point for an electric grid.

In contrast, time-domain electric grid simulations are used to determine the behavior of the system when it is perturbed away from its equilibrium point, often with an eye towards accessing the stability of the grid. Stability considerations have been a part of electric grid analysis almost from its inception, with digital computer simulations dating to the late 1950's [3]. A classic, yet still pertinent summary of the various electric grid dynamic simulation techniques is given in [4] while definitions and classifications of common types of power system stability issues are given in [5] and [6].

While time-domain simulations can consider a wide range of timeframes, the focus here is on the seconds to minutes timeframes of [5], in which the electric grid dynamic are represented as a set of differential-algebraic using integration with step sizes on the range of ¼ to ½ cycle. Historically the term "transient stability" has often been used for these types of simulations. However since the issues of interest here encompass more than just rotor angle stability in this paper these will be known as dynamic simulations, with the power system state at any particular time point referred to as a snapshot.

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For a given system, the power flow and the dynamic simulation are, of course, related. In particular, the power flow solution is used to initialize the dynamic simulation. That is, in a typical study the power flow should provide the initial quasi-static equilibrium. However, during this initialization it is quite common that some of the dynamic state variables derived from the power flow solution can result in initial limit violations. This is usually handled by either 1) changing the dynamic model limits or 2) initializing the dynamic study with limits enforced resulting in a starting point that is not an equilibrium point. Then, during the dynamic simulation one or more contingency actions are applied. The impact of the protection system can be either explicit through external actions (i.e., opening a faulted transmission line at a pre-specified time) or implicit by including a representation of the protection system in the system's models. The simulation is then usually run for a specified time to determine the system's post-contingency response.

The focus of this paper is on considerations associated with the inverse problem of initializing a power flow solution from a particular dynamic simulation snapshot. That is, the dynamic simulation is initialized from a power flow solution, a contingency is applied, the simulation is started, and at some point during the simulation the power flow is re-initialized from the simulation at this point. This could be done either from pausing a traditional batch type dynamic study or during an interactive dynamic simulation such as those presented in [7] and [8]. It is important to differentiate these simulations from the more traditional ones done in dispatcher training simulators [9] in which all buses have the same frequency and the power balance equations are ultimately solved using a power flow (i.e., a uniform frequency model). Here more complete dynamics are represented resulting in each bus having a potentially different frequency, at least temporarily. As might be expected, this dynamic snapshot can result in initial power flow limit violations, with this paper addressing these issues.

Before getting into the details it is helpful to address three questions that might arise. First, why would one want to do this; i.e., what is the need? Second, why not use state estimation? Third, assuming the power flow approach, what

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issues need consideration? The paper is organized in three parts. First, the first two questions are addressed with a motivating example also introducing some issues needing consideration. Second, various issues are addressed associated with initializing a power flow from a dynamic snapshot. Third, results are demonstrated using example systems with up to 2000 buses [10].

II. Questions Answered and a Motivating Example

The first two questions are inter-related in that what is being proposed here is actually quite similar to what is accomplished with a state estimator in a utility energy management system. Originally presented in [11] and with a good overall coverage given in [12], state estimation (SE) is widely used in grid operations to take a potentially large number of imperfect measurements and a grid model, and then determine the state values (e.g., the bus voltage magnitudes and angles) that best match these measurements. The SE results are then used as inputs for the grid analysis applications including on-line power flow, contingency analysis and optimal power flow. While originally applied to quasi-steady state models, SE is currently being enhanced to better handle the power system dynamics [13]. In the problem being addressed here of initializing a power flow from a dynamic simulation snapshot certainly an SE could be used. However, since in a simulation all of the results can be considered perfect (i.e., they exactly satisfy the underlying equations) an SE is not needed. Hence the complications associated with having and maintaining an SE can be avoided. Rather, as shall be shown, the power flow can be directly initially from the simulation snapshot, albeit with the need to address several issues first.

These issues can be motivated by using a 37-bus, 60 Hz system from Chapter 12 of [14] with the oneline and initial conditions shown in Figure 1. Both power flow and dynamic modeling information is provided, including models for the generator machines, exciters and governors (in particular the exciters are represented with IEEET1 models [15] and the governors with TGOV1 models [16]). A color contour is used to show the initial power flow per unit voltage magnitudes [17], and the line (i.e., transmission lines and transformer) flows and percentage loads are showing using flow arrows and pie charts respectively [18]. In this example the operating condition and line flow limits have been modified slightly to insure that the initial condition has N-1 reliability. During the power flow the common constant power load model is used, and fixed generator minimum and maximum reactive power limits are used. During the dynamic simulation the load is represented using the previously common constant current real and constant impedance reactive model (known as the PI/QZ) [19].

To highlight the issues, a 20 second dynamics simulation is performed in which the rather severe contingency of the loss of the bus at the Slack345 bus (located in the upper right-hand corner of Figure 1) is applied after one second. Figure 2 shows the time-varying frequency response.

Note that during the initial few seconds post-contingency the bus frequencies are not the same, with the values coalescing as the study progresses with the end frequency determined mostly by the R values for the TGOV1 models.

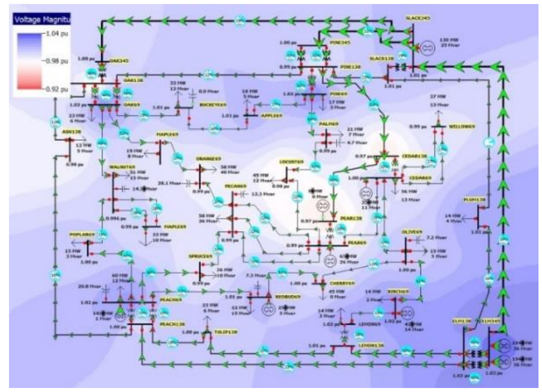

Figure 1: Example 37-Bus System – Prefault

Figure 3 plots the real power output from the generators while Figure 4 shows their reactive power outputs with the values for the generators at the PEAR69 and CEDAR69 buses highlighted in black and red respectively. Most germane here, except for the first few seconds these values exceed the maximum generator reactive power limits of 60 Mvar at PEAR69 and 26 Mvar at CEDAR69. Figure 5 shows the system oneline at the end of the simulation.

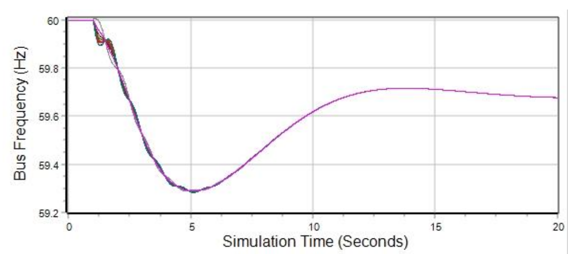

Figure 2: Example 37-Bus Frequency Response

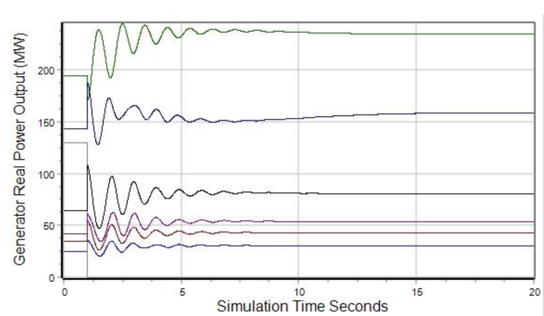

Figure 3: Example 37-Bus Generator MW Outputs

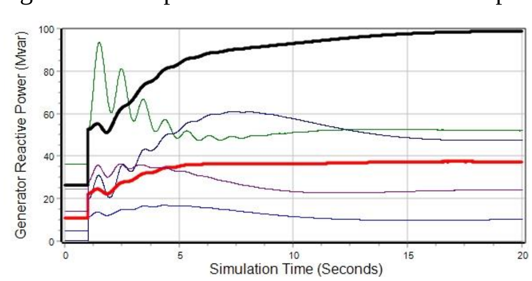

Figure 4: Example 37-Bus Generator Mvar Outputs

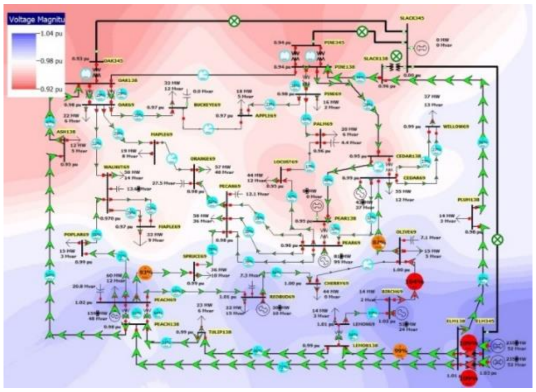

Figure 5: Example 37-Bus System – After 20 Seconds

The consideration of this paper is the initialization of a power flow solution at any point during this simulation. At first glance one might consider just doing a standard power flow simulation of the contingency. However, this would not correctly represent the final system state since different models from those in the power flow are used during the dynamic simulation. And actually in this example the power flow does not even have a solution for this loss of bus contingency due to its use of a constant power load model (a useful discussion of the impact of the load models on power flow solutions is given in [20]). Even if the dynamic PI/QZ load model is used in the power flow the solution shown in Figure 6 is substantially different.

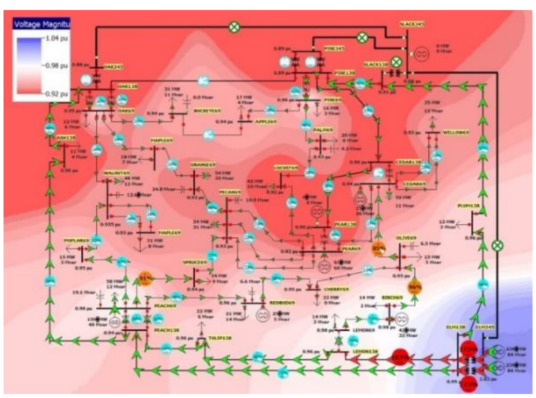

Figure 6: Example 37-Bus Post-Contingent Power Flow Solution using the Dynamic PI/QZ Load Model

A key reason for the difference between dynamic results in Figure 5 and power flow results of Figure 6 is the modeling of the generator reactive power limits, with no explicit reactive power limits enforced during the dynamic simulation. Both modeling approaches can actually be correct, with the differences arising because of the assumed problem time frames. During the time-domain dynamic simulation the generators' reactive power limits could certainly be exceeded particularly during the first 20 seconds post-contingency in which the generators' over-excitation limiters have not responded [21], [22]. As a quasi-static tool, the power flow usually gives a solution after many of the power system automatic and human operator initiated actions are assumed to have occurred.

More details are provided in the next section, but the premise of this paper is that by selectively modifying the power flow limits and automatic control assumptions the simulation results can be used to initialize the power flow at any point during a dynamic simulation. The tradeoffs in doing this are between fidelity to the original power flow limits and the snapshot dynamic simulation values. To complete this example the snapshot power flow solution at 20 seconds would exactly match the dynamic solution if 1) the load model was changed to PI/QZ, 2) the generator MW values were set to match those from the dynamic solution, 3) the generator voltage setpoints were changed to match the snapshot values, and 4) when violated the generators' reactive power limits are set to match the snapshot outputs.

This then leads to the first question posed in Section I of "why?" But before addressing "why" it is important to briefly comment on "how?" For this approach to be useful it must be implemented in a way that is essentially transparent to the user. That is something that has been done in the software used for this paper. Using the techniques presented here, at any point during a simulation a user can pause the simulation, transfer the results (utilizing various options discussed in the next section) and immediately solve a power flow representing that snapshot.

While there are numerous reasons for why one would want to do this, two are briefly considered here. First, this can be used as a quite effective power systems educational tool. For example, as presented in [23] and utilizing the software from [7] interactive dynamic simulations are now regularly used to teach students about grid operations including during severe system disturbances. Previously because the system was in a dynamic state during the simulation the students did not have the ability to use any sort of power system analysis tools to contemplate what decisions to make. Now, however, by utilizing the techniques presented here to get a power flow solution a wide variety of other analysis techniques are available to students include sensitivity analysis, contingency analysis and security constrained optimal power flows. This analysis could be done either by pausing the simulation, or doing the analysis simultaneously while the simulation continues to run, more correctly matching what would occur in an actual grid.

Second, the approach presented here can help engineers better understand how corrective control could be used during system dynamic events. This would include helping them to design Remedial Action Schemes (RAS), also known as Special Protection Schemes (SPS), defined by NERC as, "A scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a system(s)" [24]. Guidance on how RAS are currently designed is given in [25], [26], and [27]. The next sections give additional insight in how the ability the paper's focus can be used for RAS design.

III. Power Flow Considerations With Exmaples

This section provides additional detail on the tradeoffs in the power flow initialization between fidelity to the snapshot dynamics solution and the original power flow model. These tradeoffs arise because of different problem timeframes. As a starting point, because the dynamic simulation and the power flow use a similar network model, when the results are transferred to the power flow post conversion it can be setup so there are no initial mismatches. Whether it should be is the consideration of this section. In particular, the section considers the models for the loads, the generator real and reactive power, area interchange constraints, the automatic control of load-tap-changing (LTC) and phase shifting transformers, and the automatic control of switched shunts. An implied assumption is that any status changes from the dynamic simulation (e.g., the open transmission line) are transferred to the power flow.

It should be noted that for all these models, it is feasible to use the original power flow models used to initialize the dynamic simulation (taking into account topology changes). However, this is generally not advisable, as the state of the dynamic simulation at any given snapshot is likely different from the initial operating conditions post contingency. Instead, it is generally more appropriate to adjust the models based on the snapshot that is to be used to re-initialize the power flow.

For the loads, when transferred to the power flow the nominal load (i.e., the load specified at 1.0 per unit) is adjusted so that at the snapshot bus voltage magnitude the dynamic and power flow loads match. For example, if in the dynamic simulation a constant impedance model is used and in the power flow a constant power model is used, for a 100 MW nominal load at 0.9 p.u, the equivalent power flow value would be 81 MW. Of course a power flow only can use static models, whereas a dynamic simulation can use a host of static and/or dynamic models (with [19] providing more details). Various techniques are available for converting dynamic models into a static approximation [28], recognizing that any such conversion is an approximation.

The setting of the generator real power outputs is tied to assumptions about how automatic generation control (AGC) associated with area interchange is modeled. In a power flow this interchange is often modeled as an algebraic constraint for each area by setting generators to control its interchange using either participation factor control or some sort of economic dispatch (with [29] providing addition details). At a snapshot solution the area interchange could certainly be different. Options for handling this include 1) assuming all the generator real power outputs are fixed at their snapshot values (i.e., any subsequent power flow changes are picked up at the system slack), 2) adjusting the area interchange values to match the snapshot values and using generator participation factor control, 3) adjusting the area interchange as in 2) and keeping the original power flow area control method, or 4) using all the options from the original power flow. The first three options will result in no initial area interchange mismatches (i.e., inadvertent interchange), but they differentiate in how the generators will change during a power flow contingency.

As an example, consider a 2000-bus, eight area, 500/230/161/115 kV synthetic grid [10], [23] (available online at [30]) whose oneline is shown in Figure **7** that is initially operated with no line overloads and all areas managing their interchange. Next, assume a rather severe bus open contingency occurs at a 500 kV bus in the yellow region (part of the North Central [NC] Area) shown in Figure **7** resulting in the loss of several 500 kV transmission and transformers lines, and 786 MW of generation. The time-varying area inadvertent is shown in Figure 8 with the NC area having the large negative value and the other areas positive values because of the governor response of their generators. A zoomed view of the yellow region at 20 seconds post-contingency is shown in Figure 9 when the system frequency is at 59.97 Hz.

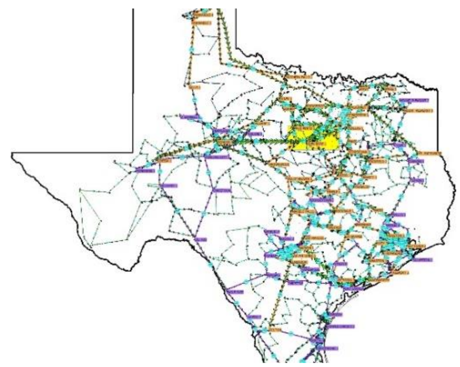

Figure 7: 2000-Bus System Oneline

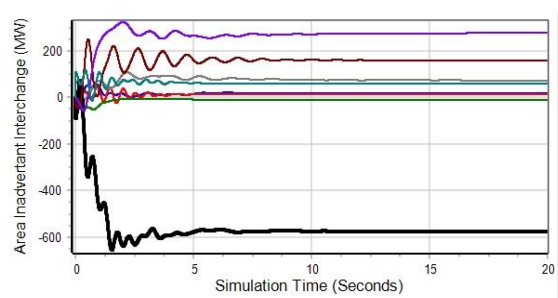

Figure 8: 2000-Bus System Area Inadvertent Interchanges

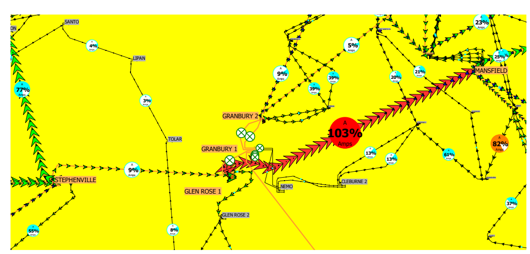

Figure 9: 2000-Bus System Zoomed View

The NC area operator (e.g. a student) is now tasked with simultaneously relieving the overload while procuring the lost generation. The various area control options provide flexibility in running the power flow or optimal power flows needed to determine what to do based on the conditions at the snapshot solution.

For AVR, the key decisions revolve around either fixing the reactive power output, or setting the voltage set points to the current snapshot values, while either maintaining or expanding the Mvar limits of the generator. As the name suggests, when re-initializing the power flow from a snapshot and fixing the reactive power output, the generator is treated to have a fixed reactive power output, similar to PQ buses in traditional power flow, which have fixed real and reactive power. One may also set the voltage setpoints, but the reactive power limits of the generator must be considered.

Electing to maintain the Mvar limits of the generators at their original values results in constraints on the actual voltage at the bus. If the voltage setpoint cannot be reached given all available reactive power support at the bus, then the actual voltage will, at best, only be close to the voltage setpoint. However, expanding the reactive power limits, the actual voltage at the bus is more likely to reach the desired voltage setpoint.

Transformers exist to either step up or step down voltages throughout the system, depending on where the electricity is flowing. The two primary transformers that are looked at are load-tap-changing (LTC) and phase shifting transformers. In particular, the decision comes down to whether a fixed voltage setpoint or a fixed tap ratio is desired. For LTCs, in the case that a fixed voltage setpoint is preferred, when re-initializing the power flow, the voltage setpoint of the transformer is set to match the current voltage at the regulated bus. In the case that a fixed tap ratio is desired, the voltage of the regulated bus will change based on the current tap ratio. For phase shifting transformers, the setpoint of the transformer is some real power flow value, usually the flow through the transformer. This value is controlled by adjusting the transformer's phase angle either automatically or by a human operator. When fixed phase shift taps are needed, the real power flow is changed based on the existing tap ratios from the snapshot.

The final power flow model that needs discussion is switched shunts, which are split into two categories; discrete switched shunts and continuous switched shunts. When re-initializing the power flow, the options are similar to prior models; either the reactive power output of the switched shunts is fixed, or the voltage setpoint of the switched shunts is changed to the snapshot value. Fixing the reactive power output of a switched shunt sets the reactive power output of the shunt to the snapshot value, and the voltage of the bus is changed as a result. On the other hand, changing the voltage setpoint of the switched shunt is similar to changing the voltage setpoint of the transformer, in which the switched shunt will change its reactive power output in order to maintain the voltage at the regulated bus.

Choosing to fix either the voltage setpoint or reactive power output of the switched shunts is heavily dependent on the snapshot values. For example, snapshots with extremely large or small voltage setpoints, such as during faults, can potentially run into issues associated with available reactive power support from the switched shunts. Thus, fixing the voltage setpoint is generally ill-advised during these situations. On the other hand, there may be instances where the reactive power output of the switched shunts from the snapshot is different from its initial values. In this case, fixing the reactive power when re-initializing the power flow will treat the switched shunts as having a different capacity from the initial case. This is primarily a consideration with discrete switched shunts, which often have fixed values.

An example of this is illustrated using the 37-Bus system from Section II in which the same severe contingency is applied at time equal one second. Figure 10 shows the voltage response at several buses across the system, while Figure 11 shows the oneline at the end of the study. At this end time an engineer could be tasked with using the power flow to correct any system limit violations. Using the techniques from this paper, an example solution is given in Figure 12. While there are a number of solutions involving adjusting tap ratios and shedding load to solve the case, the principle of transferring the dynamic state to a power flow facilitates the use of analytic tools to solve the problem.

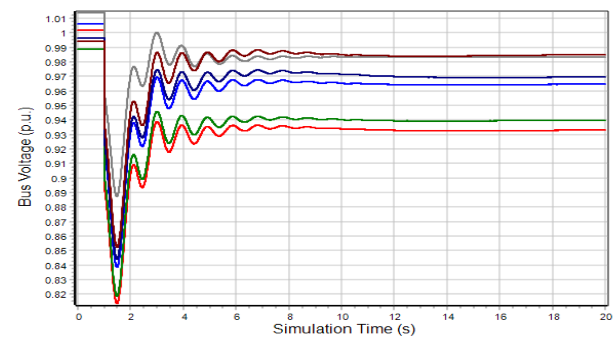

Figure 10: Voltage Variation at Several Buses

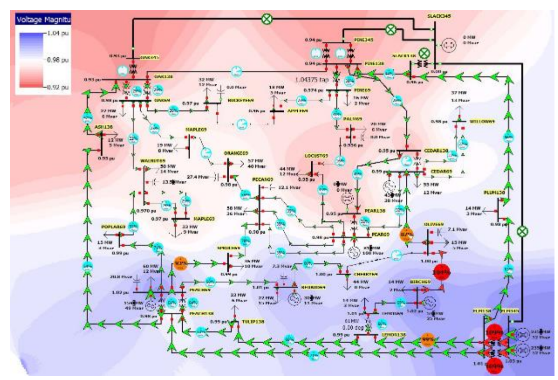

Figure 11: Final 37 Bus System State, with Violations

IV. Conclusions

This paper has presented an analysis of the considerations that are necessary when re-initializing a power flow from a dynamic simulation snapshot. Power flows provide an initial point from which dynamic simulations begin, but the reverse requires making judgments on a case-by-case basis. This paper covers prior work relating to power flow and dynamic simulations, then provides a motivating example, displaying key differences between dynamic studies and power flows if appropriate considerations are not made when re-initializing

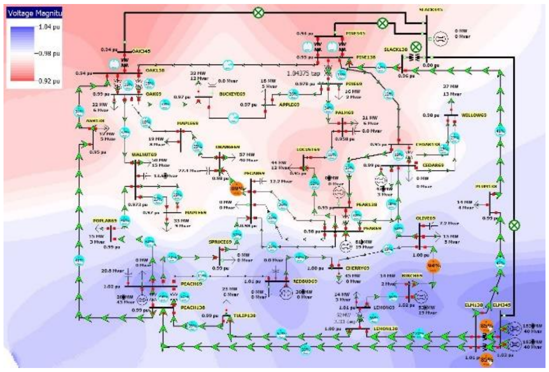

Figure 12: Corrected 37 Bus System State, No Violations

power flows from snapshots. The paper then presents the variety of models that need to be considered, along with simulation examples involving said models.

However, there are many future applications and enhancements to the approach that are currently being researched. This paper provides a basis for educational platforms, which give students an understanding of what needs to be considered when handing contingencies, along with a basis for simulation-based energy management systems, which are useful for training future engineers in appropriate decision making when operating the grid.

V. ACKNOWLEDGEMENTS

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