System Dynamic Model Validation using Real-Time Models and PMU Data

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***Abstract*— High-resolution synchrophasor data recorded during disturbances has made dynamic model validation more feasible. While several papers discuss the validation of individual components such as governors and exciters, few consider the validation of the system model as a whole. It is a challenging problem for larger systems due to the sheer number of dynamic models, and hence the states and parameters involved. This paper describes the process of validating the entire system model, up to an interconnect level using an actual disturbance event and the PMU data captured during it. We use the state estimator snapshot captured just before the inception of the disturbance, which is also known as the real-time model. The paper details the important steps of setting up dynamic model data in these real-time models, and addresses issues commonly encountered during validation such as correcting "bad data". The methodology is illustrated using an actual large system model.**

***Index Terms*—model validation, real-time system model, dynamics, PMU data, disturbance event.**

I. Introduction

A. *Background*

The accuracy of power system models and studies, including dynamic simulations, is important for making reliable and economical decisions for operating the grid. Hence, a lot of emphasis has been laid on model validation over the past few decades. This was exacerbated by the blackouts observed in the major North American Interconnections, as well as system-wide oscillation events that are more common in the West [1]. Models were not always able to reflect these behaviors in simulations. With phasor measurement unit (PMU) data becoming increasingly available, we can re-create these events and perform more rigorous comparisons, tune parameters and/or update models as needed.

This paper focuses on the method for validating the entire system model as a whole, rather than individual components (which are also important to validate). The main difference is that the latter usually only needs PMU data from the point of interconnection of the device to the grid, or internal measurements from the generator or load itself. There are also fewer states and parameters to manage. For the system model, the process is a lot more involved, starting from the number and types of devices, their interactions, and wide-area impacts. In this paper, we make use of transmission system-level voltage and frequency measurements, to compare with simulation results.

The first version of this work by the authors appeared in [2], which began in 2012. The methodology of using the state estimator (SE) snapshot from just before the start of the event, and mapping dynamic data to it had been implemented in [2], but the process was partly manual. In addition to this, there are industry reports such as [3] from 2014, and at least one paper [4], which make use of the North American Western Interconnection (WECC) real-time model to perform validation. They provide valuable insight into the specifics of the WECC system and the software packages used, with a focus on benchmarking simulations with measurements. This paper, on the other hand, provides a generic method to perform validation on a real-time model, which is independent of the footprint, software package, and such specifics. The focus is on the systematic steps taken to fix common errors encountered in this process. The goal is to enable meaningful comparisons for any case, and not particularly to provide detailed comparison results for the example system shown in this paper.

B. *Motivation for Using a Real-Time Model*

It is interesting to note that prior to [3] and [4], planning models i.e. off-line power flow models containing dynamic data were used to validate system models using disturbance events. Power flow conditions and statuses were mapped into these planning models from real-time models that were extracted around the time of the event occurrence. For instance, a system model validation study for a 2013 event [5] used a planning case with similar load levels as the day when the event occurred, and an SE snapshot was used to derive generation levels. A reason for this can be the fact that the North American Electric Reliability Corporation (NERC) MOD-033-01 (Steady-State and Dynamic System Model

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Validation) standard requires comparing the planning power flow model to actual system behavior [6], [7], similar to the NERC Validation Procedure published before in 2013 [8]. In fact, this standard also partly serves as a motivation to this paper. The methodologies described here can help tackle some of the practical issues that may be encountered while validating dynamic system models.

Another reason we use the real-time model for our dynamic simulations is due to its structure. Typically, such models consist of a detailed "node-breaker" representation of the network, which describes the full topology of the network as is. In contrast, planning models are a consolidated version of the network; they consist of buses and branches and hence lack detailed information about breaker statuses and configurations within substations. While the latter is a less data intensive version of the system, a major disadvantage is that contingencies involving breakers cannot be modeled accurately. Also, the different formats across real-time and off-line models (node-breaker vs bus-branch) make model management challenging, leading to discrepancies and modeling errors. Work is ongoing to benchmark real-time and planning models with actual events [9], since mismatches between them and their simulation results were found during the Arizona – Southern California 2011 blackout analysis [10]. In the longer term, NERC has recommended that offline models should be slowly transitioned from bus-branch into the node-breaker format, someday converging entirely to the latter [11]. Cognizant of this, we use the SE snapshot (i.e. real-time model) for our analysis in this paper.

The paper is organized as follows. Sections II-IV describe the overall methodology of validation, with the help of an example. In particular, Section II details the input data and models used in this process, Section III focuses on the dynamic data adjustments whereas Section IV considers actual simulation issues. The paper's key takeaways are summarized in Section V.

II. INPUTS

This section describes the key input data and parameters used or required to meet the goals of this paper. Since we use models and data pertaining to an actual power grid for illustration, any identifying information such as a system oneline, names of buses, etc. has been concealed for confidentiality. In terms of size, the system can be considered to be on par with that of an interconnection, consisting of tens of thousands of buses. The system is known to have dynamic events from time to time such as oscillations, making validation and event analyses major areas of interest in this region. The data corresponds to an actual event that occurred in the spring of 2014, which led to generator outages followed by low frequencies throughout the system, but not low enough to cause violations.

A. PMU Data

A perturbation is needed to excite the states of a dynamic model, so that it can be validated. Hence, data recorded by PMUs during system events is used. They record measurements such as voltages, currents, angles, typically 30-60 times a second in data historians. Due to their large size, data files can be made available in standard formats such as COMTRADE for off-line purposes. For system model validation, ideally the event should be such that its impact is widely observed, e.g. a major generator outage. If the focus is a particular area of a large interconnect, then the disturbance should be local in nature, such as the closing of a transmission line [8]. At times, tests are conducted where the system is intentionally perturbed to validate specific models. For a system model analysis and validation, simulation outputs that give a high-level view of the system such as MW flows across transmission corridors and important transmission lines, voltages and angles at key buses, etc. would typically be considered. The measurements from the 2014 event used in this paper were available only from transmission system level PMUs, i.e. around 40 PMUs located in a particular area/subsystem of this large system, which is also where the disturbance originated. Bus voltage magnitudes and angles, frequencies, and flows on lines (real and reactive power, current) were available at voltage levels higher than 200 kV nominal. Note that no PMU measurements were available from generator and load points of interconnection. Two minutes of data was provided, with the important event dynamics spanning around 60 seconds.

B. Sequence of Events

The next important point is to know what occurred in the system during the disturbance. This can be considered as applying one or more transient contingencies. To maintain confidentiality, we do not enumerate the detailed sequence of events; however the main events are summarized here. The disturbance started with a fault on a key transmission line, which was cleared by opening it. This was followed by opening of several generators, interspersed with switching of reactive power devices. Overall, it was a frequency disturbance. The events occurred in quick succession and had to be carefully simulated. For example, how many MW were dropped in each plant with the opening of multiple units in the plant, amount of vars switched in or out, etc. has to be matched. As shown later, errors in modeling certain switching events can cause major differences. Gathering the correct sequence data is crucial to make a sound validation case.

C. System Model: Real-time and Planning

SE snapshots are available in an Energy Management System (EMS). For the system under consideration, SE snapshots were saved in the EMS every 15 minutes. We chose the most recent snapshot available that was captured before the inception of the fault mentioned earlier. This represents the closest known state of the system near the start of the disturbance, and can be considered as the starting point or initial power flow solution. In our case, the SE snapshot was taken 8 minutes before the disturbance began. The differences in the initial voltage values at some buses did indicate that things may have changed in that time. In such instances, local SCADA data if available can be used to adjust for more recent changes in the system. Such data was not available to us so we proceeded to use the SE power flow solution as is, as an approximation. Another interesting point to note is that, due to issues with the state estimator solution, one of the remote areas of our interconnected system model had to be excluded from the real-time model. In other words, that area appears as "disconnected" in the real-time model, even though it was connected in real life. While the boundary flows were adjusted to account for this, disconnecting this area impacted the dynamics, as shown further in the paper.

Currently, dynamic models of actual system models are set up to be used with planning cases only. This is true for planning models of all the three US Interconnections. Real-time models contain no dynamic data in themselves and hence dynamic simulations for validation are not possible directly. Dynamic models and data have to be added or mapped into real-time models, the only current viable source being planning models. Every system has a number of planning models available based on 1) the year, 2) loading level (heavy, light), and 3) season (summer, winter, spring). We chose the planning model, whose above three characteristics best matched the conditions prevailing during the disturbance. These happened to be "2014, heavy, spring" and the data of such a planning case was mapped into the aforementioned SE snapshot.

D. Dynamic Data Transfer

The term "dynamic data" refers to the models and parameters representing generators, loads and other devices that have time-varying characteristics. They are used when a dynamic simulation is performed, which involves solving a system of differential algebraic equations that describe these models. The process of getting this dynamic data into the SE case is not straightforward, due to the lack of a one-to-one correspondence between the planning and real-time model bus/node names and numbers. In such a case, a mapping is needed between the planning model bus numbers and names versus the real-time model node names. For actual, large-scale systems such mappings have to be meticulously developed in cooperation with regional entities. For instance, for the Western Interconnection there is a mapping [4] available which maps real-time and planning case generators through the use of invariant labels in the former, and invariant bus numbers for generating units in the latter.

Using the mapping provided to us for our study system, we were able to map 92% of the generation in terms of the MW output. There was no mapping available for loads, hence certain assumptions were made for loads in the SE case, as discussed further in the paper.

III. DYNAMIC DATA CORRECTION AND CHANGES

A. No Disturbance Run

Once all possible dynamic data is mapped, mostly generator related such as involving machines, exciters, governors, stabilizers etc. it is now possible to perform a dynamic simulation. To make sure the simulation is numerically stable, it is a good practice to run it for 5 or 10 seconds with no contingency. This is known as a "no disturbance run" (NDR) and the desired result is a flat response i.e. no movement in the response variables. Typically, simulation outputs such as bus frequencies, generator speeds, and voltages are monitored to track the response to an NDR. If the response variables show changes when no perturbation or contingency is applied, the simulation

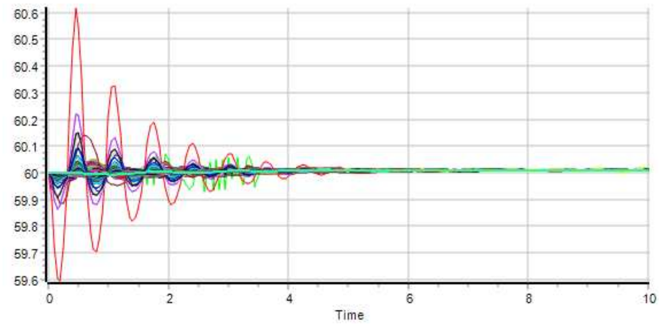


Figure 1. Results of a no disturbance simulation.
Y axis is Bus Frequency in Hz.

is not stable and hence any further results obtained from simulating contingencies are not to be trusted. This is why it is also a good practice not to apply any contingency for at least the first one second in all dynamic simulations. Varying response to an NDR is typically caused by incorrect or inconsistent dynamic model parameters, which can cause issues during initialization of the models. Figure 1 shows bus frequencies for an NDR. Such large deviations clearly warrant further investigation into the dynamic data.

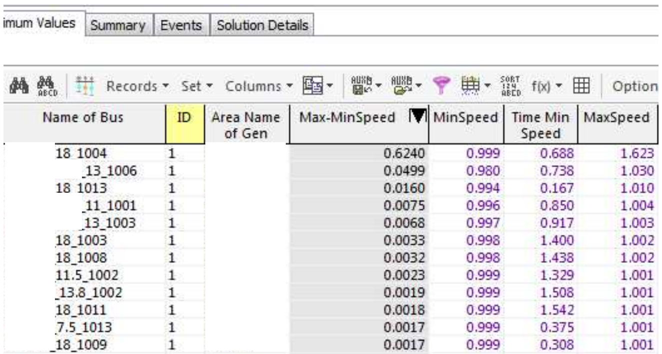
B. Negative MW Generators with Governors

As mentioned earlier, the dynamic models and parameters were set in accordance with the planning model conditions, including the generator dispatch. A common theme among certain unstable generators in the simulation of the real-time model, shown in Figure 1 was that each of their MW outputs were < 0 MW in the real-time model, and they had governors included in the simulation. This was causing those generators to be unstable. The negative output was due to the hydro units operating as synchronous condensers or as pumped storage in reality (real-time), and the governor models were assigned for a positive MW dispatch in the planning model. Hence, a data check for this condition is suggested, i.e. if generator MW output < 0, then disable the governor model if it exists. On disabling these, all such generators were found to run stable.

C. Correcting MVA Base Values

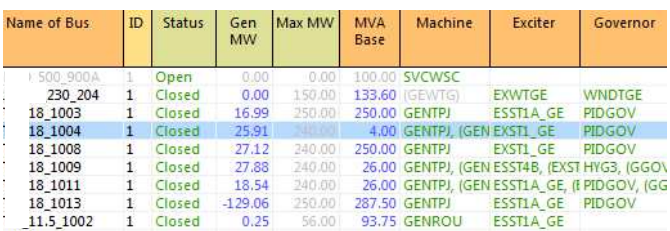
Dynamic parameters such as machine impedances, inertia, etc. are all defined in per unit (pu), with the generator or machine MVA base typically used. Hence, for the same parameter values, using a different base can produce drastically different results. Power flow models, both planning and real-time also have a data field for generator MVA base. Inconsistencies in base values among both these power flow models and the dynamics database can cause generator instabilities in simulations. An example of this is the generating unit at a plant that had the maximum speed deviation during the NDR. Results such as those shown in Figure 2 are a good way to pick out the most unstable units. Note that the names of the buses have been partially "whited out" to conceal identifying information.

The results show that several units (namely 1003, 1004, 1013, etc.) in the plant "____18" deviate a lot. Figure 3 shows details associated with these units, namely the MVA base, MW capacity and some dynamic models. Looking at the data of the most deviating generator "____18_1004", we see that its maximum capacity is 240 MW, yet its base is only 4 MVA. Heuristics and engineering judgement dictate that such a combination of parameters is unlikely, since typically generator MVA base values are around the MW capacity or within 1.2 times of it.



Name of Bus	ID	Area Name of Gen	Max-MinSpeed	MinSpeed	Time Min Speed	MaxSpeed
18 1004	1		0.6240	0.999	0.688	1.623
_13_1006	1		0.0499	0.980	0.738	1.030
18 1013	1		0.0160	0.994	0.167	1.010
_11_1001	1		0.0075	0.996	0.850	1.004
_13_1003	1		0.0068	0.997	0.917	1.003
18_1003	1		0.0033	0.998	1.400	1.002
18_1008	1		0.0032	0.998	1.438	1.002
11.5_1002	1		0.0023	0.999	1.329	1.001
_13.8_1002	1		0.0019	0.999	1.508	1.001
18_1011	1		0.0018	0.999	1.542	1.001
7.5_1013	1		0.0017	0.999	0.375	1.001
_18_1009	1		0.0017	0.999	0.308	1.001

Figure 2. Screenshot of results showing top generator speed deviations for the no disturbance run. Bus names partly whited out for confidentiality.



Name of Bus	ID	Status	Gen MW	Max MW	MVA Base	Machine	Exciter	Governor
500_900A	1	Open	0.00	0.00	100.00	SVCWSC		
230_204	1	Closed	0.00	150.00	133.60	(GEWTG)	EXWTGE	WNDTGE
18_1003	1	Closed	16.99	250.00	250.00	GENTPJ	ESST1A_GE	PIDGOV
18_1004	1	Closed	25.91	240.00	4.00	GENTPJ, (GEN	EXST1_GE	PIDGOV
18_1008	1	Closed	27.12	240.00	250.00	GENTPJ	EXST1_GE	PIDGOV
18_1009	1	Closed	27.88	240.00	26.00	GENTPJ, (GEN	ESST4B, (EXST	HYG3, (GGOV
18_1011	1	Closed	18.54	240.00	26.00	GENTPJ, (GEN	ESST1A_GE, (E	PIDGOV, (GG
18_1013	1	Closed	-129.06	250.00	287.50	GENTPJ	ESST1A_GE	PIDGOV
_11.5_1002	1	Closed	0.25	56.00	93.75	GENROU	ESST1A_GE	

Figure 3. Screenshot of Unit 18_1004 parameters which has maximum speed deviation. Suspect MVA base observed.

Hence, the next step is to set up checks for suspect MVA base values. If the MVA base is less than 0.5 times the MW capacity, we set the MVA base to 1.1 times the MW capacity. This is a conservative check, i.e. we could increase the threshold to more than 0.5 if needed. The incorrect MVA bases in this case arose from the real-time model. Since it has no dynamics, the base values of these generators played no role until the dynamic data was mapped, which most likely had a different base in the power flow case of the planning model they came from. Figure 3 also shows an example of a unit with negative MW with a governor, "____18_1013", which was ultimately disabled.

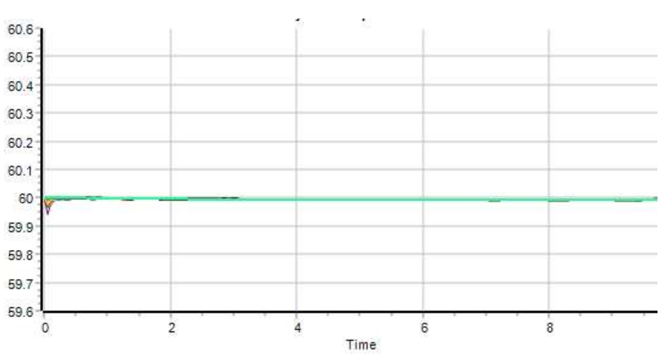


Figure 4. Bus frequencies during a no disturbance simulation, after the dynamic data checks and corrections

After these data checks were applied, another NDR was performed which yielded the results shown in Figure 4. It uses the same Y-axis scale as Figure 1 for easy comparison, with both showing frequencies at all the buses. The deviations are now gone, with a flat response obtained for the NDR as desired, aka a "flat start" (not to be confused with a power flow flat start).

D. *Load Modeling*

The end of Section II.D briefly mentioned the existing unavailability of load mappings, making the data transfer to real-time models not possible. Loads were especially complicated since in the dynamics part of the planning case they were represented by composite load models, which consist of 100+ parameters constituting different types of motors, protection, electronic load, and a feeder for instance. Another complication is that they are defined by regional model groups. To transfer these parameters to a real-time model without some kind of mapping would be infeasible. To address this, certain assumptions had to be made about the load. For instance, before the advent of such complex, composite load models, there were "interim" models used by industry to represent three-phase induction motors. Another common type of load model used in dynamic simulations is the ZIP model, which is defined as a mix of a ratio of constant impedance (Z), constant current (I), and constant power (P) models, which may also have a frequency dependence component.

A PIQZ model (real power constant current, reactive power constant impedance) was used for most of the areas in the real-time case, while remaining few had constant impedance models. All loads in the case were assumed to have a 20% three-phase induction motor component. Both these assumptions are consistent with the modeling used in previous versions of the case. The composite load model was mainly introduced since prevailing models were unable to exhibit phenomena such as fault induced delayed voltage recovery (FIDVR). Since FIDVR is not a concern for the system/subsystem and disturbance under consideration, using these simplified models is sufficient in our case.

IV. SIMULATIONS

After getting a flat start as described in the previous sections, the system model is now suitable to be run with the sequence of events as its transient contingencies. The goal is to compare results of this simulation at those buses where PMU data is available. To automate this, a mapping between PMU labels and the bus/node labels in the real-time model is useful. Since neither of these labels are bound to change much, except for additions, this mapping can be re-used to validate more models and events, appending to it as more PMUs are added. This section also shows the sensitivity of the results to some of the input parameters mentioned earlier, such as using the real-time model versus an off the shelf planning model, the season of the planning model from which the dynamic data is derived, and the significance of accurately modeling switching events.

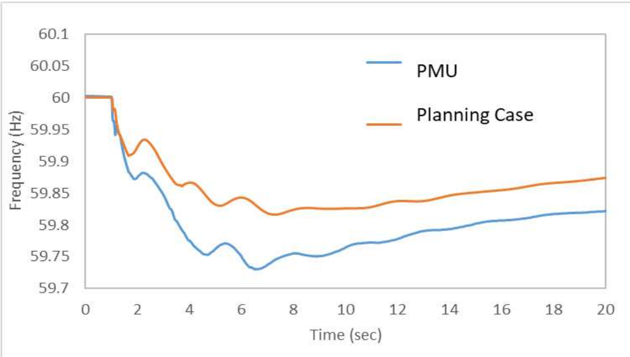


Figure 5. Frequency comparison at a 500 kV bus when a relevant planning case is used as is

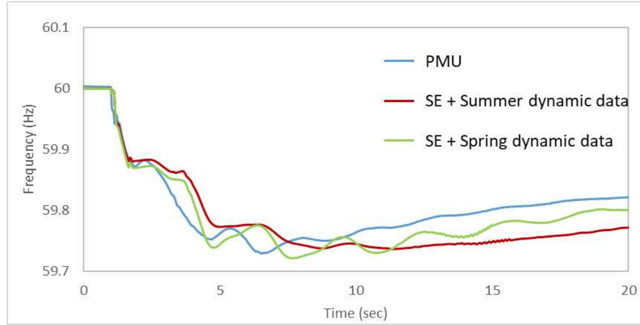


Figure 7. Effect of using dynamic data from different season planning models in the same year; spring is a better match.

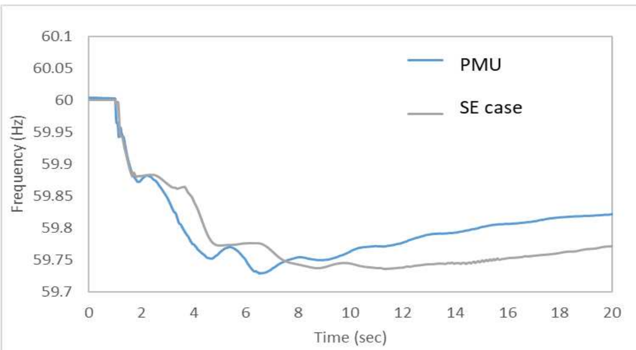


Figure 6. Frequency comparison at a 500 kV bus when dynamic data from a relevant planning case is mapped into a state estimator model

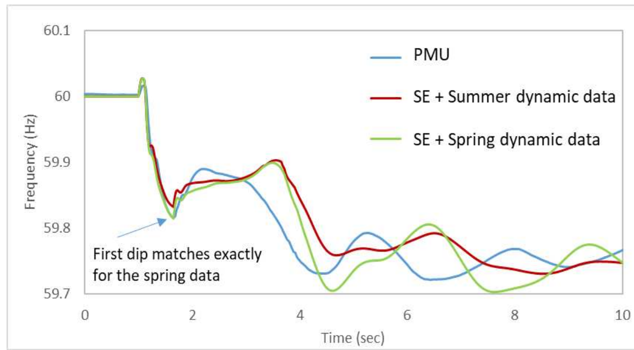


Figure 8. Frequency results at a different 500 kV bus to show seasonal dynamic data impacts on the first dip

A. *Frequency Comparisons*

1) *Planning (as is) vs Mapped Real-Time Model*

Since this event had generator drops, bus frequencies showed interesting behavior. Figure 5 shows a comparison of frequencies at a 500 kV bus. A "relevant" planning case, i.e. one matching the load level during the year the event occurred was used as is, with no changes to the power flow model to account for the system state as it was during the disturbance. A difference of almost 0.1 Hz in the lowest frequency values between the simulation and PMU data is evident in Figure 5. In contrast, when the dynamic data of the above planning case is mapped into the SE snapshot, the frequency results improve, as shown in Figure 6. Particularly, the first dip and the minimum values are much closer now.

2) *Summer vs Spring Data*

The dynamic data used in Figure 5 and Figure 6 came from a 2014 summer planning case. Since this event occurred around the end of spring - beginning of summer, the SE case was also mapped with dynamic data from a spring planning case to see the impact. Figure 7 shows an improvement in the minimum and final frequencies. Figure 8 shows frequencies at another 500 kV bus, zooming in to the first 10 seconds. Using the spring dynamic data causes the first dip of simulated frequency to match the measured value quite well. Note, these two buses are located in two different parts of the system and somewhat representative of all the measured frequencies. The frequencies near each of these are different but follow a similar trend, indicating the global property of bus frequency and frequency disturbance propagation.

B. *Voltage Comparisons*

Next, we compare bus voltages. Unlike frequencies, voltages show a lot more variation in response across buses due to their localized nature. In order to sift out the bus voltages that differ the most, it is better to automate the comparisons rather than manually look at each set of curves. Common metrics such as Euclidean distance, i.e. L2 norm, L1 norm as described in [12], or correlation co-efficient can be used to quantify the difference between two time-series signals. From a transient stability perspective, methods such those proposed in [13] may be used, which yield an overall stability assessment result instead of having to rely on off-line, visual comparisons of signals.

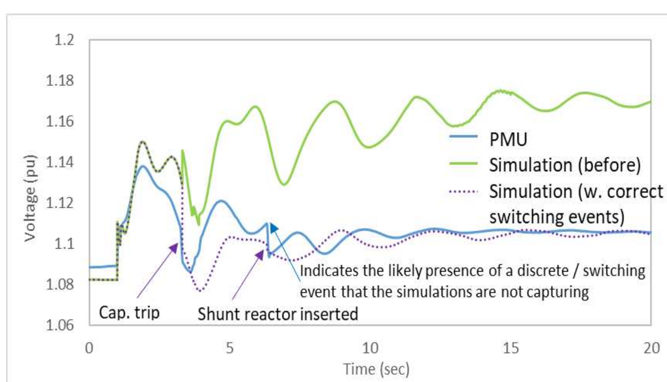


Figure 9. Voltage comparisons at a 500 kV bus before and after accounting for reactive power switching events

Using such automated comparisons, Figure 9 shows the bus which had the "largest distance" between the simulated (green) and measured (blue) voltages. Looking at the PMU data, two discrete events are noticeable which cause the voltage to decrease, one before t=5 sec, and one after that. In the original simulation, neither of these events were included in the sequence of events (data was unavailable). Once these results were found, a deeper search was conducted to identify any more events in this time frame, only to find that at t=3.3 sec., a capacitor had tripped off, while at t=6.3 sec. a shunt reactor had been inserted, close to the location of this bus. Once these events were included, results shown in the purple dotted curve were obtained, showing a significant improvement in the voltage simulated.

The localized nature of voltages makes it harder to match simulations with measurements, as compared to frequencies. Steady state differences also lead to different initial voltage values, which is not the case with frequencies so often. We have also found that bus voltages show more (localized) oscillations than frequencies. At times, high frequency oscillations are observed in simulations, which do not exist in the PMU data. Some wind units, most of which are small in capacity, mainly cause these oscillations. Dynamic data of some wind models is still not entirely stable, especially when coupled with real-time models. If these are remotely located and not significant in MW output compared to the system of interest, they may be disabled without causing a major impact, except getting rid of the oscillations.

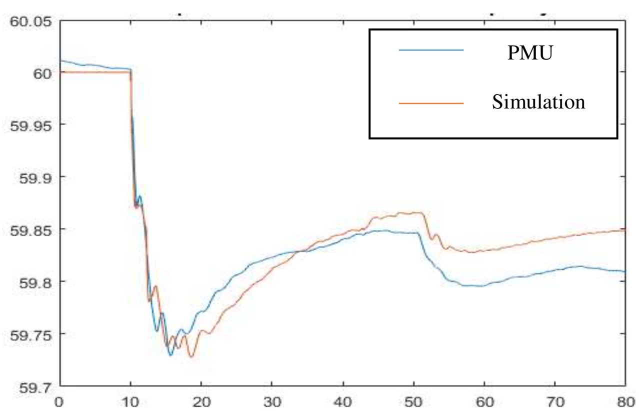


Figure 10. Frequency comparisons over 80 seconds

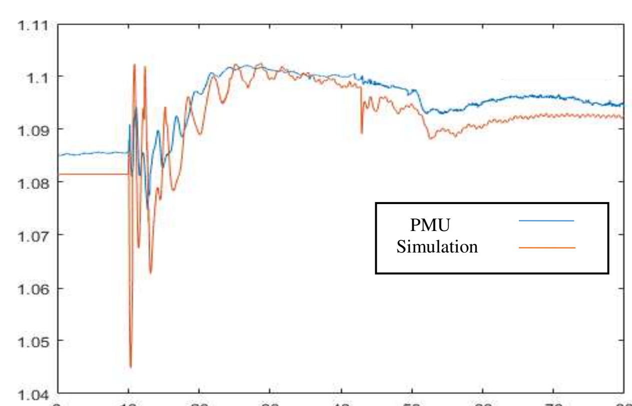


Figure 11. Voltage comparison over 80 seconds

Figure 10 and Figure 11 show the frequency and voltage results at different buses. We see evidence of the frequency matching more closely, and the voltage oscillating more. There is also a high frequency oscillation beginning at about 30 seconds in the simulated voltage. This was due to an oscillating, remotely located wind unit, which was later disabled. At this stage, the "validation base case" is ready and it can be used for further comparisons of major line flows, or a parameter estimation type of validation to resolve the existing discrepancies. One parameter to adjust to bring frequencies closer would be governor response limits.

C. *Overall Methodology*

Figure 12 summarizes the overall system model validation process. The green boxes (parallelograms) represent the different inputs and data used, as described in Section II. The grey rectangles list the steps taken such as data processing, simulations, comparisons, and updating parameters. In this paper, we focused on changing system based parameters such as sequence of events data, using heuristic methods. After the steps in this paper, if further improvement of simulation results is needed, one can do more in-depth analysis of the system's individual components if PMU data from generator terminals or loads is available. Sensitivity analysis such as in [14] can be helpful in such cases, where the exciter parameter and state space is reduced to make the problem more tractable. This followed by parameter estimation will enable automation of this approach.

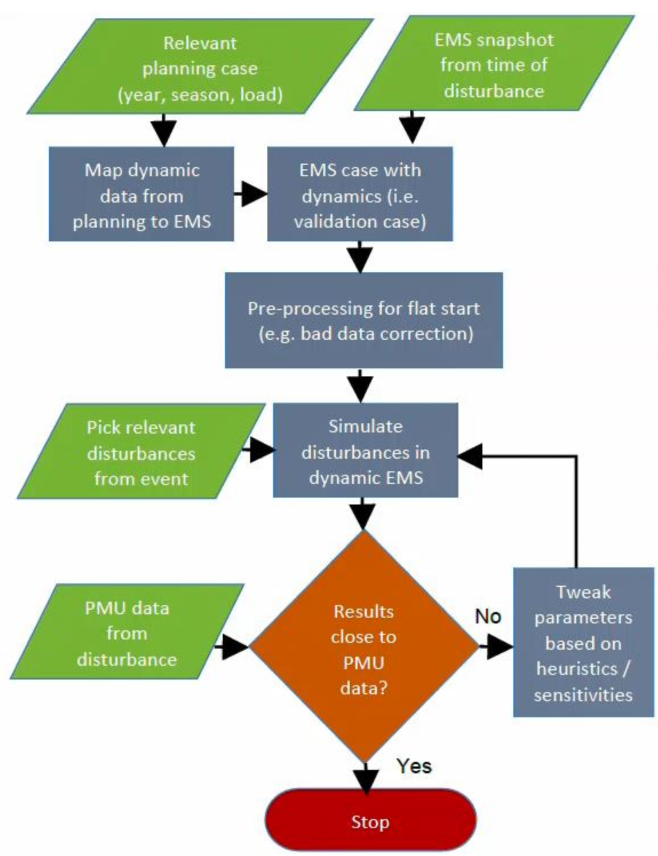


Figure 12. Overall Validation Process

D. Challenges of Using SE Snapshots

The paper so far showed the benefits of using SE models derived from an EMS. However, these may not be perfect. For e.g. the SE snapshot used in this study had one area disconnected in the EMS due to non-convergence. On deeper investigation, which is beyond the scope of this paper, it was found that exclusion of this area from the simulation was indeed causing the 1) low damping, and 2) slight shift in the frequency of oscillation. Such practical issues have to be addressed to derive a usable model that is representative of the real state of the whole system, or a suitable equivalent of the area of interest. Planning models on the other hand are rigorously designed for long term studies and vetted with the dynamic data, and so are less likely to have such issues.

V. Summary and Future Work

This paper presented a method to validate the dynamics of large-scale system models, which can also be used to re-create system events in post mortem analysis. This was done because current literature mostly provides comparison results or high-level procedural steps, and not the practical issues pertaining to data and models likely to be encountered with planning and real-time models. This paper provided some of the key initial steps in system model validation, and setting it up for more detailed analyses. Ongoing work is looking into improving system level results when only high-voltage level measurements are available, using systematic methods such as sensitivity analysis and parameter estimation. In addition, how local measurements such as generator or load PMU data can be used in this validation process will be looked into. Finally, acquiring a complete real-time model of this system to assess improvements in the simulation results described in this paper will also be pursued.

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