Applications of DC Power Flow Based Power System Dynamic Simulations

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Abstract—The increasing amount of power electronic devices and inertia-lacking generation have introduced more complexity in power system frequency stability analysis. For power system operations, quick analysis of system frequency response following contingencies is desired. Building upon the uniform frequency approximation, an approach commonly used in operator training simulators, this paper proposes a method of power system dynamic simulation using a uniform frequency approximation coupled with a dc power flow. This method is compared with the full frequency stability study using two case studies of different system sizes. In this paper, the computation time and performance of the two methods are compared, and the applications of the proposed method are also discussed.

Index Terms—Frequency stability simulation, dc power flow, uniform frequency approximation, operation training, power system education

I. Introduction

Stability refers to the capability of a power system to remain in synchronism during major disturbances such as outages, faults, and sudden load changes. Studies are performed to analyze initial system response and to determine whether, following a contingency, the power system will return to a new steady-state operation [1]–[3].

For decades, transient stability has been one of the highest areas of focus for system stability [4], and with the nation's energy generation portfolio changing rapidly, the importance of studying system responses to contingencies has only continued to increase. More renewable energy is being installed while older traditional units are being retired [5], [6], causing the system to respond differently to grid events.

Dynamic models are used to analyze how the system will respond within the first few seconds to outages or contingencies, providing an opportunity to mitigate risks before they occur. In the past, direct methods for analyzing power system stability were used to predict critical clearing times, assess system security, and develop strategies for emergency state control [4], [7]. Today, due to the introduction of many more synchronous machine stator current dynamics and voltage source converter dynamics, as well as the implementation of more inertia-lacking energy generation, the ultra fast changes in states of the electric grid in the time directly following a disturbance create a need for more complex, faster methods of modelling and analyzing power system stability [2].

A common method for performing analyses of power system stability for highly complex systems is creating models that can simulate the system within shorter time frames by use of approximations or different mathematical models [8]–[11]. Without the use of approximations, computation time for these models is slower than real-time, making the models unusable in emergency situations, large-scale systems with very detailed models, or in educational and training purposes when students have only an hour or two of classroom time.

Frequency stability simulation using uniform frequency approximation requires less computational efforts while providing similar results with respect to frequency transients. This method assumes a uniform frequency among system nodes, and ignores the inter-area oscillation and the different between individual generator frequencies [11], [12]. It is commonly used in system operation training platforms, where the simplification of frequency stability simulation can provide a faster frequency response to assist operation decisions [11].

Building upon the assumption of uniform system frequency, this paper proposes a method which uses both uniform frequency approximation and a dc power flow formulation to provide a frequency stability simulation with much shorter computation time. This method ignores fast dynamics from the synchronous machine, exciter and stabilizer models, but still uses governor models, and only focuses on the transient in a relatively longer time frame. Two case studies using public test cases of different system sizes are presented in this paper to compare the computation time and performance of our proposed method with the full frequency stability simulation. The applications of this proposed method are also discussed, where the accuracy of frequency transients can be traded off in exchange for much faster computation time.

II. DC Power Flow Based Frequency Stability Formulation

As mentioned in Section I, the two differences between a standard frequency stability problem and the proposed dc frequency stability formulation are that we are using a dc power flow and uniform frequency approximation in order to solve our frequency stability problem. The dc power flow makes the assumption that all bus voltages are set at 1 pu , and that we can neglect reactive power and line conductance [13]. Thus, the ac power balance equations

$$P_i = \sum_{k=1}^{n} |V_i||V_k|\Big(G_{ik}\cos{(\theta_{ik})} + B_{ik}\sin{(\theta_{ik})}\Big) \quad (1)$$

$$Q_i = \sum_{k=1}^{n} |V_i||V_k|\Big(G_{ik}\sin{(\theta_{ik})} - B_{ik}\cos{(\theta_{ik})}\Big) \quad (2)$$

can be simplified, resulting in

$$\theta = -\mathbf{B}^{-1}\mathbf{P} \quad (3)$$

where θ consists of the voltage angles at each bus, B is the imaginary component of the Y_{bus}, and P is the vector of real power injections. The dc power flow is faster to solve than the ac power flow, and is always guaranteed to have a solution [13].

The dc power flow provides two simplifications to the frequency stability problem. One, because we've fixed all the voltages in the system to be exactly 1 pu, exciters are not necessary, as their primary purpose is to control the synchronous machine field voltage [14]. Furthermore, the dynamics of the machine are faster than the time frame considered in the proposed methodology, so they can be ignored.

The second assumption of the proposed methodology is a uniform frequency approximation. This assumes that the frequency at every bus in our system is the same. In a standard system where we do not assume a uniform frequency approximation, it can be observed that on weak tie lines, generators at one end of the tie could oscillate against generators at the other end of tie, resulting in low frequency oscillations [15]. As a result of the generators oscillating against one another, low frequency oscillations would arise, which are damped out by power system stabilizers [16]. However, with the uniform frequency approximation, the low frequency oscillations no longer exist, and as such, we do not need to consider power system stabilizers in our system.

Thus, the proposed methodology is as follows. A dc power flow is used to initialize the system at steady state, and remains at steady state until a contingency occurs. When a contingency occurs, the steady state is disturbed and we must solve for the generator dynamics in order to observe the behavior of the system. The differential equation solved for in the dc frequency stability is (4), where M_T is defined as the total inertia in the system, and a is defined as the accelerating power, which is the different between the total mechanical and electrical power in the system [17].

$$M_T\dot{\boldsymbol{\omega}}_{\boldsymbol{o}} = a \quad (4)$$

The results of solving (4) for the behavior of the frequency at the next time step is used as input to the governor model, which adjusts the mechanical power of the generator. However, because there are no machine models considered, the changes from the governor model are reflected as changes in generation in the system. Thus, our dc power flow must be re-solved with in order to determine the line flows. However, by introducing the accelerating power a, we have also adjusted the dc power flow equations seen in (3), where for any generator i, we have (5), where M_i is the inertia at a specific generator [18].

$$\Big(P_{Gi} + \frac{M_i}{M_T}a\Big) - P_{Li} = -B_{ii}\theta_i \quad (5)$$

III. Simulation Results and Comparisons

This paper compares the effectiveness of frequency response computation using the proposed method and the conventional full frequency stability simulation. The uniform system frequency formulation of the proposed method is mentioned in the previous section. For the conventional method, the inertia-weighted average generator frequency is used, where a full ac power flow based frequency stability simulation is conducted to compute the individual generator frequencies.

It is important to note that since the assumptions of dc power flow based dynamic simulation (DCPF) and the uniform frequency approximation (UFA) ignore faster dynamics from the synchronous machine, exciter, and stabilizer models, and only focus on the dynamics in a longer time frame, a larger step size can be used in the simulation to reduce the computation time. In this paper, a full frequency stability simulation adopts a 0.5-cycle time step, while the proposed method uses time steps of 6, 12, and 24 cycles as comparisons.

Two case studies using the public test cases of difference sizes and complexities are included. The first case study uses a 37-bus test case from [19] as a proof of concept. The second case study uses a 2000-bus synthetic system, which has more realistic size and complexity to the real transmission system. The synthetic power system test cases and scenarios are developed in the work of [20]–[22]. They are created to be realistic and fictitious, and do not contain any confidential information about the actual grid. They can be downloaded, used, and published freely from [23].

The average computation time of each simulation method is recorded. The approximated system frequencies from the two different methods are compared with the individual generator frequencies from a full frequency simulation.

Three evaluation metrics are developed to quantify the accuracy of each method's system frequency response representation compared to the individual generator frequencies. Inertia-weighted mean error calculates the average mismatch between the calculated system frequency and individual frequency of synchronous generators in the system, where more weight is put on synchronous machines with higher inertia values. The mathematical formulation of inertia-weighted mean error is shown in equation (6).

$$\text{Inertia-Weighed Mean Error} = \frac{\sum\limits_{i=1}^{Ngen} \left(h_i \sum\limits_{j=1}^{Ntime} \mid X_{ij} - Y_j \mid \right)}{Ntime \times \sum\limits_{i=1}^{Ngen} h_i}$$

(6)

where:

$Ngen$	number of synchronous generators
$Ntime$	number of time steps for the system frequency result
h_i	inertia for generator i
X_{ij}	frequency of generator i at time step j
Y_j	approximated system frequency at time step j

As the minimum frequency after a contingency is an important measure for power system reliability standards [24], the gap between the lowest value of individual generator frequencies, and the lowest system frequency is used as another evaluation metric. The inertia-weighted correlations between generator frequencies and approximated system frequencies measure their similarity from the perspective of time series. It is used as the third metric to quantify the effectiveness of the two methods.

A. Case Study 1: 37-Bus System

The 37-bus system is a public test case from [19]. This system has voltage levels from 350 kV to 69 kV. It serves a total load of 813 MW with nine generators with total generation capacity of 1347 MW. The one-line diagram for the 37-bus system can be found in Figure 1.
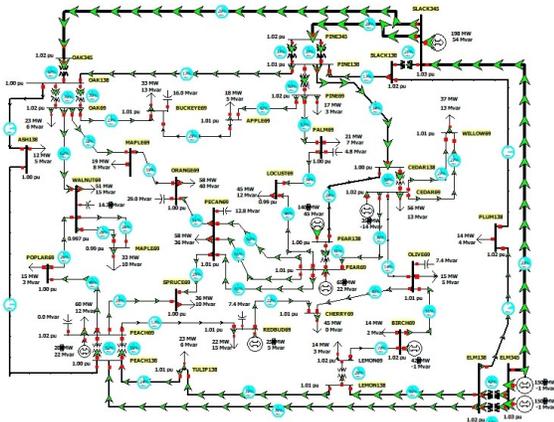

Fig. 1. One-line Diagram for the 37-bus Test Case

The case study simulated a contingency with generation loss, where generator PEAR69, a unit with 110 MW generation capacity that serves about 8% of the system load, is disconnected from the system at $t = 1$ sec. We conduct

four simulations, all with different simulation settings; a full frequency stability run with a 0.5 cycle time step, and three dynamic simulations using both dc power flow and uniform frequency approximation with a 6-cycle, 12-cycle and 24-cycle time resolution. All the simulations have duration of 20 seconds.
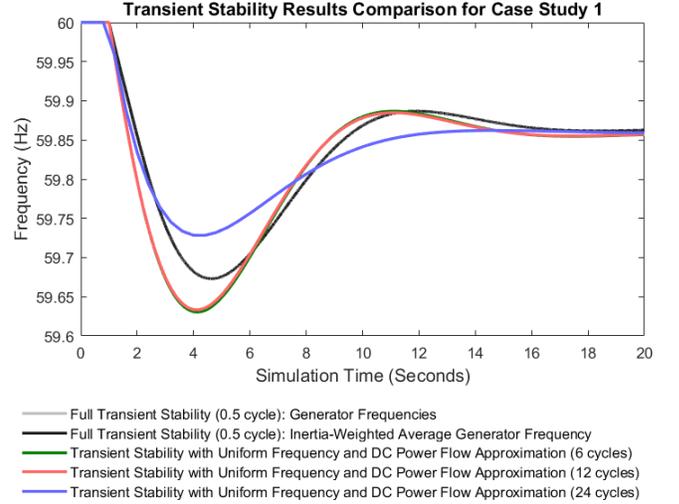

Fig. 2. Frequency Stability Results Comparison for Case Study 1

Figure 2 presents the results from the simulations of this case study. Similar behavior is observed across the simulations as the frequency drops when the contingencies are applied and gradually recover. As the 37-bus test case is small in size, the variations of individual generator frequency are relatively conforming, thus the inertia-weighted average system frequency is almost identical to the individual generator frequencies. The simulations with dc power flow and uniform frequency approximation exhibit slightly different frequency waveforms with different step size used. The 6-cycle and 12-cycle time step frequency responses have lower nadir value compared to the inertia-weighted average frequency, while 24-cycle time step simulation yield to a higher minimum value. All of the simulations return to a similar steady-state frequency value by the end of the 20-second simulation.

TABLE I
FREQUENCY STABILITY SIMULATION RESULTS COMPARISON FOR CASE STUDY 1

Simulation Method	Simulation Time (Sec)	Weighted Mean Error (Hz)	Minimum Frequency Gap (Hz)	Correlation
0.5-Cycle Full TS	14.5	0.000	0.000	1.000
6-Cycle UFA + DCPF	1.1	0.016	-0.042	0.974
12-Cycle UFA + DCPF	0.6	0.016	-0.040	0.974
24-Cycle UFA + DCPF	0.3	0.019	0.056	0.970

Table I presents summary statistics for the simulations. The time to run the 20-second simulations range from 0.3 seconds to 14.5 seconds, where the full power system stability has the longest computation time, and the 24-cycle UFA + DCPF takes the shortest. Recall that the weighted mean error presents an average error metric, as the inertia-weighted average frequency is almost identical to the generator frequencies, the mean error is close to zero. The weighted mean error increase as the step size becomes larger, with the 24-cycle case having the largest mean error with 0.019 Hz deviation. The minimum frequency gap presents the difference between the simulation's lowest frequency and the value of the generator with the lowest frequency observed over the duration of the simulation. The 6-cycle and 12-cycle simulation have 0.042 and 0.040 Hz deviation below the minimum generator frequency. The 24-cycle simulation have 0.056 Hz difference above the min generator frequency. The correlation provided measures the similarity between individual generator frequencies and the frequency of the system using each simulation method, which ranges from 0.970 to 1.000.

B. Case Study 2: ACTIVSg2000 Synthetic System

The ACTIVSg2000 synthetic system is a public test case that contains 2,000 buses on the footprint of United States ERCOT Interconnection. This synthetic system has voltage levels from 500 kV to 115 kV, and serves a total load of 67 GW with generation capacity of 100 GW. The one-line diagram of ACTIVSg2000 synthetic system can be found in Figure 3.
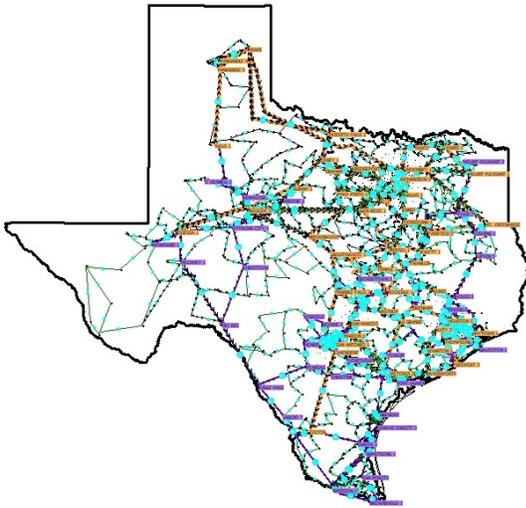

Fig. 3. One-line Diagram for the ACTIVSg2000 Test Case

The case study simulated a contingency of major generation loss, where generator WADSWORTH 4, the largest unclear unit in the system with 1354 MW generation capacity, is disconnected from the grid at $t = 1$ sec. Similar to case study 1, the simulations include a full frequency stability run with a 0.5-cycle time step, and three dynamic simulations using both dc power flow and uniform frequency approximation

with a 6-cycle, 12-cycle and 24-cycle time resolution. All the simulations have duration of 20 seconds.
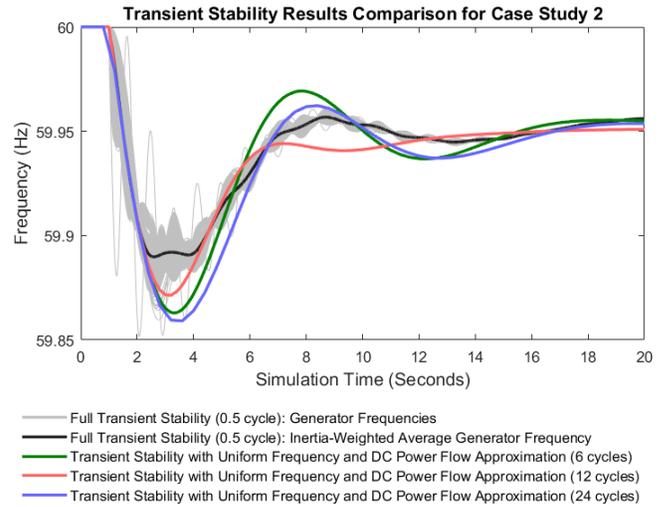

Fig. 4. Frequency Stability Results Comparison for Case Study 2

Compared to the 37-bus system case study, as the size of the system increase, inter-area oscillations tend to magnify. Thus the difference between individual generator frequencies is more obvious and it creates a grey band in Figure 4. The frequency at generator WADSWORTH 3 has the least conforming variation compare to the rest of the system, as it is attached to the same substation as the unit experiencing the outage. The black line in the figure shows the inertia-weighted average frequency, in this case has the highest nadir value compared to other simulation results. The 24-cycle UFA + DCPF simulation has the lowest nadir frequency.

Table II presents summary statistics for each simulation run in Case Study 2. As observed in Case Study 1, a greater level of approximation in the case yielded faster simulation times. The simulation times range from 0.6 seconds to 24.7 seconds, the fastest of which was recorded for the 24-cycle UFA + DCPF simulation. The weighted mean error is lowest at 0.003 Hz in the full frequency stability simulation and greatest at 0.008 Hz in the simulation with uniform frequency and dc power flow approximations with a 24-cycle time step. The correlation ranges from 0.946 to 0.981.

As the size and complexity of the power system increases, a full frequency stability has a much longer simulation time relative to the simulations that use dc power flow and uniform frequency approximations. On the other hand, as more approximations are made in the various simulation methods, the less representative the system frequency response is compared to the individual generator frequencies. An overall trend of decrease in evaluation metrics values can be observed.

Simulation Method	Simulation Time (Sec)	Weighted Mean Error (Hz)	Minimum Frequency Gap (Hz)	Correlation
0.5-Cycle Full TS	24.7	0.003	0.038	0.981
6-Cycle UFA + DCPF	1.5	0.008	0.011	0.946
12-Cycle UFA + DCPF	1.0	0.006	0.020	0.955
24-Cycle UFA + DCPF	0.6	0.008	0.008	0.964

IV. APPLICATIONS

A. Fast Screening for Power System Dynamic Response

One of the main applications for the dc power flow based frequency stability is the notion of fast screening techniques when observing the response of a system. In large systems where there are numerous models for generators, getting to understand the behavior of the system from a holistic view does not necessarily mean that one needs to understand the exact behavior of every generator. As such, dc power flow based frequency stability provides a method of being able to observe the overall behavior of a system without needing to understand how each individual element in the system responds to contingencies.

An example implementation of fast screening would be testing the resiliency of a grid to a variety of contingencies. In this case, one would be interested in observing how the system progresses as the event occurs, but may not be interested in how every generator in the system reacts to the event. A dc power flow based frequency stability approach allows for the quick testing of a multitude of contingencies on any system, while still expressing an approximation of the the behavior of the system that would be useful for an overall gauge on how resilient the system is to a specific contingency.

B. Education and Training on Large-Scale Power System Operation

The proposed methodology is also applicable in the field of power system operation education and training. Currently, there has been multiple uses for large-scale synthetic power systems in education, ranging from single-user experiences on contingency analysis and economic dispatch [25], to multi-user experiences in operating a synthetic power grid [9], [26], all on the scale of about 2,000 buses. The work of [11] has also developed a dispatcher training simulation platform using uniform frequency approximation, where approximated system frequency response can be provided to system operators without long waiting time.

In providing a tool that allows for even quicker frequency stability simulation on larger systems, the dc-based approach also removes some of the hardware limitations. In particular, large-scale power system test cases that have the real-life size and complexity can be used when understanding power system

dynamics and how certain actions can impact larger grids in almost real-time.

This would provide students with an opportunity to develop an intuition on how to operate large-scale power grids while remaining within the time constraints of labs or classes. For the operation training, the dc-based approach can provide good quality frequency transients analysis of the power system in a much shorter time for major disturbances involving large frequency deviations.

C. Frequency Transients Analysis for Combined Transmission and Distribution System

Furthermore, a dc-based frequency stability approach also allows the dynamic analysis for higher resolution data in combined transmission and distribution (T&D) power systems. Because the focus of dc-based frequency stability is to make approximations in order to speed up computation time while still producing acceptable results that would roughly mimic the behavior of the actual system, large scale T&D power system models that are highly detailed can be simulated.

The ability to simulate system frequency response for highly-detailed T&D system models enables the potential for infrastructure coupling, and also increases the situational awareness for system operations.

For example, in the case of extreme weather and natural disasters such as hurricanes and wildfires, the frequency response results with information from the distribution-level grid would assist operators to better understand the system conditions, where quick judgments and mitigation plans can be made based on the relative success of such implementations without having to wait for extended periods of time for simulations to finish.

V. CONCLUSIONS AND FUTURE WORKS

The level of approximation in the simulation presents an engineering choice as a trade off between accuracy and frequency speed. The most detailed simulation, the full frequency stability simulation, takes a relatively long time to run each simulation, yet provides high fidelity in its simulated system response. The simulation with the highest level of approximation, the 24-cycle uniform frequency and dc power flow approximation simulation, takes little time to run the simulation, yet provides a more approximate representation of the system behavior. The dc-based approach to frequency stability has a litany of potential applications including use as a screening tool for power system contingency response, expanding the possibilities of education and training on large-scale power system operations, and for using highly detailed T&D power system models to enable infrastructure coupling and increase situational awareness.

For the future work, similar methodology can also be applied while dividing the system into areas, where each area would have its own accelerating power equation. This will address the potential issue of different regions having substantial modes and inter-area oscillations in large systems.

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