



Toward Standards for Dynamics in Electric Energy Systems

Executive Summary

S-55

Power Systems Engineering Research Center

*Empowering Minds to Engineer
the Future Electric Energy System*



Toward Standards for Dynamics in Electric Energy Systems (S-55)

Final Project Report

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Executive Summary

Overall summary

The goal of our research is to define criteria and a systematic method for advancing the current control/automation in power systems for the purpose of guaranteeing transient stabilization during severe, yet anticipated contingencies. This is very important since such criteria/requirements for the dynamical components when interconnecting to the grid do not exist. As such, these dynamical components lack specific control objectives, relevant for the stability and the performance of the large power grid. This situation has many implications since as power grids become more dynamic the stability and the performance of the grid will be greatly challenged. In addition, various types of generators, wind generators, storage and Flexible AC Transmission systems (FACTS) need to have specific objectives which if met, will enable them to assist on maintaining the stability and the performance of the interconnected grid. Based on these distributed stability criteria, the control and automation of each component can be defined accordingly (for meeting those requirements). Today, the current automation used in power systems is linear constant-gain-based AVR controllers that are not designed to meet any specific stability requirements at the component level. Because of this, their contribution to the stability of the large power grid is not clear. These controllers are at best able to guarantee stability and performance in a small neighborhood around the equilibrium point and correspondingly respond in a stable way to small disturbances only. Because of this, the performance of the currently used transient stability controllers, during large severe disturbances, is greatly challenged. Today's power systems are experiencing many dynamical problems ranging from small-signal instabilities, frequency instabilities, voltage instabilities to transient instabilities, sub-synchronous resonance (SSR) and transient instabilities, such as loss of synchronism. Undoubtedly, one of the most critical dynamical problems is loss of synchronism since in the most known wide-spread blackouts transient instabilities were the main cause. In fact, loss of synchronism typically initiates a sequence of cascading events that lead to blackouts.

While the range of dynamical problems that power systems experience at present still has not been significantly affected by the integration of renewables, it is expected that this will change in the near future. The reason is that the integration of renewable energy resources in the US system is still very low. Nonetheless, numerous wind generators and PVs are expected to get connected to the bulk energy system (BES) grid and to produce a significant amount of the total US electricity demand in the near future. Such high integration levels, are going to alter the dynamical behavior of the system during transients. Therefore, transient instabilities will become even more critical and need to be addressed carefully. The only standards related to transient stabilities today are the North American Electric Reliability Corporation (NERC) transmission planning (TPL) standards. These are concerned with the planning of a power system such that at various loading levels and under expected severe contingencies, it remains transiently stable. Such an approach, suffers from several drawbacks. First, it is prone to inefficiencies i.e. to causing operation of power systems far below its real equipment capabilities. Second, it is expensive i.e it results to high costs of transmission expansion to meet the worst-case stability criteria. Third, it does not relate the system-wide transient stability requirement to transparent criteria that various dynamical components,

such as synchronous generators, have to meet. The above points make the need for simple plug-and-play standards for transient stability more pronounced.

Our approach to overcoming these problems fundamentally relies on advanced control and automation to ensure provable/guaranteed transient stability and performance for the assumed known set of contingencies. The first part of the proposed approach is defining stability criteria that different components have to meet, either on their own or as a group. We then relate these distributed stability criteria in light of the system-wide stability. This is important for bridging the gap between system-wide stability guarantees and plug-and-play distributed stability criteria. In this report, we propose design of specifications for components and groups of components so that when these are met the system-level criteria are met. When the components cooperate to meet specified objectives as a group, communication-based control architectures are required to implement the required cooperative schemes. The second part of our approach is based on the introduction of the intelligent Balancing Authorities (iBAs), which are, groups of components that are responsible for meeting a set of stability criteria in a coordinated way. The final part of our approach discusses the development of several novel advanced nonlinear control design methods that can be used by the iBAs to meet their stability criteria.

As a proof-of-concept, we use several test cases to illustrate the effectiveness of our approach. More specifically, we use the IEEE 24-bus RT system to show that with our method the Critical Clearing Time (CCT) of the system, which is the most-common metric for assessing transient stability, is increased for the given set of probable contingencies. In this scenario, nonlinear decentralized controllers are used by the formed iBAs. The performance of iBAs with more advanced cooperative control scheme is assessed using the IEEE 14-bus system and a small 3-bus system. On the IEEE 14-bus system, we show how transient stability and voltage regulation can be achieved using an iBA comprising conventional synchronous generators. At other extreme, the 3-bus system has in addition to two synchronous generators a state-of-the-art wind generator with a fast battery storage. On this system, we show how the wind generator and the synchronous generator can define an iBA and jointly ensure that synchronous generators do not lose synchronism during a given contingency. This is achieved by means of using storage available on the wind generator.

We conclude, more generally, that advanced control-based methods can enable operation of power systems closer to their stability limits. This is because advanced nonlinear control can make an unstable contingency scenarios in closed-loop stable. Therefore, it becomes possible to reduce the need for unnecessary transmission expansions for retaining transient stability during severe contingencies. Instead, the approach offers less expensive cyber solutions to further enhancing stability of critical generators. Notably, new dynamical components such as storage, state-of-the-art wind generators and Flexible AC Transmission Systems (FACTS) can be integrated into power systems at value for improving transient stability of power systems; this fundamentally enhances stability of current systems whose controllers are only governors and AVR's of synchronous generators.

Part I: Standards and Protocols for Stable Dynamics in the Electric Power Systems

Part I of this project performed by Carnegie Mellon University (CMU) team concerns difficult questions regarding relations between: (1) the specifications which manufacturers must meet prior to connecting dynamic components (power plants, FACTS) to an electric power grid; (2) NERC standards which require that system operators do not create different types of instabilities during normal and/or contingency conditions; and, (3) standards and protocols which new equipment owners must meet prior to connecting to an electric power grid. These seemingly unrelated problems must be related in order for the electric power systems to work in the future as the grids evolve and are expected to serve supply/demand patterns for which they may have not been designed. Notably, to utilize the potential of new fast controllable technologies, such as FACTS and various fast storage, and to close the loop with synchronized sensors such as PMUs, for purposes of operating the grid more efficiently without experiencing operating problems, it is essential to establish relatively simple enforceable standards for dynamics. In particular, it is necessary to ensure that such standards will lead to provably acceptable dynamic response. Meeting these objectives is a tall order, given that at present only analyses tools exist for assessing off-line whether the system would respond in a dynamically acceptable manner (say, stay transiently stable within pre-specified critical clearing time for the given list of contingencies). This is done for given tuned controllers implemented by the manufacturers. We propose to consider standards which enhance dynamic response by requiring that (groups of) components meet their own standards as recommended in this report.

Having dynamic standards becomes particularly critical in grids with continuous net demand fluctuations. These fluctuations can only be balanced by fast primary controllers and, given lack of market and financial mechanisms to incentivize deployment of fast control and sensing, it is essential to establish technical standards and protocols.

In this report we briefly describe that relations (1)-(3) are currently not aligned, and stress the need to relate them. Two, somewhat different, approaches are proposed to overcome this problem. The first approach requires system operators to play the key role in identifying likely dynamical problems, identify equipment affected and set requirements for enhanced control for this equipment only. The second approach proposes a set of criteria which all (groups of) components must meet in order to connect to the power grid. The system operator only provides solved power flow for normal loading and equipment conditions, the range of likely load deviations and the list of contingencies for which required standards for dynamics must be met. No specific dynamic models information is required by the system operators about any equipment. Each component must either meet the set standards for dynamics by implementing its own local control and/or cooperate with the other components to meet standards for dynamics jointly. The second idea is effectively a generalization of how control authorities (areas) meet frequency regulation specifications today; we note that the AGC standards are being set without knowing characteristics of the power plants in the control area; it is the responsibility of the control area itself to know these characteristics in order to meet the AGC standards. We explain in this report how can this be defined for ensuring acceptable dynamic response more generally. We refer to the control area-like entities (groups of components jointly meeting standards for dynamics) as intelligent Balancing Authorities (iBAs).

As a result of our attempting to generalize AGC standards for frequency regulation by establishing protocols to ensure acceptable dynamic response over wide temporal ranges and during both normal and contingency conditions, we propose how such standards could be set for avoiding most typical dynamical problems. It was pointed out to us during the course of this project that the digital electronics standardization was the key to technology deployment at value. As the electric power industry evolves into more dynamic industry driven by both technological and societal changes it is essential to take a step back and attempt to set relatively simple (or as simple as possible) protocols and standards to enable dynamically acceptable operation of the changing electric power grid operation. The effort at CMU in this project is highly motivated by this situation. It is our recommendation to discuss further the proposed protocols and to make next steps into the direction of relating existing NERC standards to the standards which would lead to provable performance by requiring all (groups) of components connected to the grid to meet them. Assuming that the basic idea is of interest to the industry, further discussions with industry, NERC in particular, will be needed to move forward.

Throughout this report the emphasis has been on a representative critical standard, namely transient stability standard. Illustration of the two approaches to setting quantifiable criteria needed to ensure transient stability within a given critical clearing time for given list of contingencies is provided. We emphasize that by combining a systematic modeling of power system dynamics with model-based control design for nonlinear dynamic systems, the proposed criteria become verifiable and implementable. Illustrative examples are provided showing how the proposed standards can result in transiently acceptable system response. Future steps include generalization of the proposed transient stability standard to the set of standards for acceptable dynamics, ranging across voltage stability, mid-range dynamic response, inter-area dynamic specifications. An important open question concerns protection settings so that they do not over-ride the response set by standards for dynamics. Protection should be a safety mechanism to protect the equipment from damage, and not for managing system-level dynamic response. Special protection schemes are examples of iBAs meeting transient stability standards in a coordinated way. The difference between SPSs and the dynamic standards proposed is that protection disconnects equipment in a coordinated way. It is proposed here to, instead, achieve pre-specified transient stability according to the proposed standard using smart high-gain multi-modal nonlinear control to avoid loss of synchronism, for example. Further work is needed to establish mechanisms for coordinating the proposed dynamic standards with the protection settings in the newly emerging power grids. This is needed to avoid situations in which protection leads to loss of synchronism often experienced during major blackouts.

Part II: Standards for Dynamics in Microgrid-based Future Distribution Systems

The objective of this work done at Texas A&M is to formulate and evaluate standards for dynamics in future distribution systems. With the advance of sensing and communication technologies, we envision a “smarter distribution” system that is comprised of multiple microgrids [1]. Clusters of distributed energy resources and loads, known as “microgrids”, can be managed by local intelligent decision makers and coordinated by the distribution system operator (DSO) to achieve stable and sustainable operation. Interconnected through distribution lines, microgrids exchange power to mitigate renewable resource output fluctuation and balance out the mismatch between local power generation and consumption through aggregation effect. The dynamic performance of such a smart

distribution system heavily depends on the control architecture that manages thousands of heterogeneous resources/consumers at scale.

One of the main challenges of dynamic control architecture for future distribution grid is how to coordinate heterogeneous distributed energy resources (DERs), energy storage systems (ESSs) and controllable loads (CLs) so that the overall system performance is guaranteed. A promising solution would be to break the distribution system down into interconnected clusters [1]. As defined by the U.S. Department of Energy (DOE) [2], such resource and load clusters can be considered as a microgrid if it has a clear electric boundary. This boundary is commonly referred to as “the point of common coupling (PCC)”. In a microgrid, each power generation and/or consumption unit is controlled by its local unit controller (LUC). In addition, all the LUCs are managed by an intelligent microgrid central controller (MGCC). Then one level above, the PCC voltage of each microgrid will be coordinated by the DSO [3]. With such clustered configuration, the computational complexity and communicational burden can be significantly reduced for distribution system operation.

For the coupled operation of microgrids, it is important that proper power sharing achieved among system modules. In current practice of microgrid interface control, algorithms mimicking SG swing equations are commonly adopted to craft synthetic inertia in case that the system frequency is at risk of running into unacceptable level following resource and/or load disturbances. Such frequency droop and inertia emulation methods generate microgrid interface behavior according to the nature of SG swing equations. However, several factors limit their application for future distribution systems: 1) synthetic inertia slows down system transient response; 2) the conflict between frequency regulation requirement and the sensitivity of indicating power imbalance [4]. Taking advantage of synchrophasor measurement technology, VSI output voltage angle can be directly drooped instead of frequency to indicate power imbalance since the voltage angle of microgrid interface VSIs can be set arbitrarily as long as a synchronized angle reference is available. It has been realized that drooping the VSI voltage angle instead of frequency can be a better option for power sharing considering its advantage in transient performance and control flexibility. In angle droop control methods, signals from the global positioning system (GPS) are utilized for angle referencing, which is enabled by intelligent electronic devices (IEDs) with phasor measurement units (PMUs) embedded [4]. In the study system to be investigated in this paper, no physical interface VSI is deployed at each microgrid PCC. A virtual interfacing scheme is designed to control the PCC voltage indirectly through managing the integration VSIs of selected internal distributed generation units with synchrophasor measurement available at their respective connection point (CP).

With future distribution grids configured as microgrid interconnections, a three level hierarchical control framework is proposed to guarantee system-wide small signal and transient stability. At the primary level the model reference control (MRC) is performed, through which each microgrid interface is controlled to track a designed reference model. At the secondary level, a droop management scheme is proposed to adjust the reference model droop gains based on the stability assessment results. At the tertiary level, an AC power flow (ACPF)-based supervisory control strategy is utilized to dispatch the nominal setting to each microgrid central controller (MGCC). With such three-level control framework adopted, theoretical results on system-wide dynamic stability criteria in the sense of Lyapunov are obtained. Minimum information exchange is required

among microgrid modules and the distribution system operator, which is a highly desirable feature in energy management programs for future distribution systems. This theoretical result implies the potential of designing provably stable standards for dynamics for future distribution systems. Future work will continue to develop real-world systems and validate the dynamic performance of such real-world distribution systems.

Part III: Risk Based Transient Instability Criteria for Dynamic Reliability Standards

The objective of this research is to provide an approach for risk-based security assessment (RBSA) to define the dynamic reliability standards in the future electricity grid. Electric power system security assessment is one of the most important requirements for operational and resource planning of the bulk power system. Security assessment ensures safe operation of the power system for all credible contingencies. The traditional deterministic approach for power system planning as per the North American Electric Reliability Corporation (NERC) reliability criterion consists of evaluating operating limits or planning the system to withstand the worst-case scenario. This deterministic approach usually provides a conservative criterion and can result in expensive bulk system expansion plans or conservative operating limits. Electric utilities have to operate much below their maximum capacity due to the security margins imposed on them by the system operating criteria. Furthermore, with increased converter-based renewable penetration into the electric grid the dynamics of the grid are changing. In addition, the variability and intermittency associated with the renewable energy sources introduce uncertainty in the electricity grid. Since, security margins have direct economic impact on the utilities; more clarity is required regarding the basis on which security decisions are made.

RBSA of a power system provides a measure of the security of the power system that combines both the likelihood and the consequence of an event. Risk based methods provide more information on the security of the system at different operating conditions and can provide a basis for making decisions on security margins. A novel approach to estimate the impact of transient stability is presented in this research by modeling several important protection systems within the transient stability analysis. A robust metric to quantify the impact of transient instability event is proposed in the research that incorporates the effort required to stabilize any transiently unstable event. Two different metrics to quantify the impact of transient instability are presented. To simulate the proposed RBSA method, a synthetic test case is developed that represents upstate New York and the province of Ontario. The test case has all the major features of a realistic power system for transient stability simulations and reliability assessment. Exhaustive time domain simulations are performed on a credible list of contingencies for different fault types and location. Simulations are performed for varying system loading conditions and varying converter-interfaced renewable energy injections. Risk of transient instability events are evaluated from accurate impact assessment obtained by modeling the protection system and accurate probabilistic data obtained from the industry. The stochastic nature of converter-interfaced wind energy injection is also modeled into the risk assessment methodology. The variability and intermittency of such renewable generation should be included in the defining the standards for the future electricity grid. The effect of converter-interfaced renewable energy injection on system reliability is investigated using RBSA. The simulations results show that converter-based renewable generation injection helps in improving the transient stability limits. The simulation results show that RBSA can be used effectively in system planning to select security limits. Comparison of RBSA with

deterministic methods show that RBSA not only provides less conservative results, it also illustrates the bases on which such security decisions are made. RBSA is used to identify zones in the electricity grid with reliability issues using equal risk contour plots. Zonal risk assessment can help system planners in identifying key areas within the system that can affect system reliability. RBSA helps in identifying critical aspects of system reliability that is not possible using the deterministic reliability techniques.

Project Publications:

- [1] Y. Zhang, Y.; and L. Xie. "Online dynamic security assessment of microgrids interconnections for future smart distribution," *IEEE Transactions on Power Systems*, vol. 30, no. 6, pp. 3246-3254, November 2015.
- [2] Zhang, Y.; K. Ding, and L. Xie. "Interactive Control of Coupled Microgrids for Guaranteed System-wide Small Signal Stability," *IEEE Transactions on Smart Grids*, vol 7, issue 2, pp. 1088-1096, March 2016.
- [3] Zhang, Y.; and L. Xie. "A Transient Stability Assessment Framework in Power Electronic-interfaced Distribution Systems," *IEEE Transactions on Power Systems*, vol. PP, issue 99, pp. 1-9, February 25, 2016.
- [4] Datta, Sohom; Vijay Vittal. "Risk-Based Transient Stability Assessment for the Future Electricity Grid with High Converter-interfaced Renewable Penetration," *IEEE Transactions on Power Systems*, to be submitted.

Student Theses:

- [1] Zhang, Yun. *A Clean Slate Control Framework for Future Distribution Systems*. Ph.D. dissertation, Texas A&M University, College Station, TX, 2015.
- [2] Datta, Sohom. *Risk-based Transient Instability Criteria for Dynamic Reliability Standards in the Future Electricity Grid*, Ph.D. dissertation, Arizona State University, Tempe, AZ, 2016.

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The Power Systems Engineering Research Center (PSERC) is a multi-university Center conducting research on challenges facing the electric power industry and educating the next generation of power engineers. More information about PSERC can be found at the Center's website: <http://www.pserc.org>.

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