



Monitoring and Maintaining Limits of Area Transfers with PMUs

Final Project Report

S-64

Power Systems Engineering Research Center
*Empowering Minds to Engineer
the Future Electric Energy System*



Monitoring and Maintaining Limits of Area Transfers with PMUs

Final Project Report

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Executive Summary

The report is presented in two parts. Part 1 extends area angle monitoring with PMUs to get actionable information in emergencies. Part 2 describes structural modeling and performance metrics needed for monitoring and control of the changing electric power system.

Part 1: Monitoring and Maintaining Limits of Area Transfers with PMUs

Phasor Measurement Units, or PMUs, also known as synchrophasors, can quickly measure voltage phasor angles with respect to a common reference at multiple locations spread across the power grid. When these measured PMU angle data are made available at a control center, the challenge is to turn the data into actionable information about the power grid.

Most of the current methods have the easier objective of detecting system conditions that are anomalies or outliers. Indeed, if we subtract measured PMU angles to get angle differences, then unusually large angle differences generally correspond to stressed conditions, and these stressed conditions can be distinguished from normal operating conditions. While it is of some use to be able to detect and report that the conditions are stressed, the problem underlying the stress, whether action needs to be taken, and which action to take are not specified. That is, the PMU data processed in this unstructured way can detect a generally stressed condition, but does not provide actionable information to solve a specific problem.

To get actionable information from PMUs we need to formulate a more specific problem, and this project addresses the effect of line outages inside a particular area when there is a particular overall pattern of power flow through the area. The PMU angle measurements are made around the border of the area. We use circuit theory to combine the measured angles into a scalar “area angle” that quantifies the area stress with respect to line outages inside the area. That is, the area angle measures the impact of line outages inside the area. Offline computations can set a threshold for the area angle that is related to the N-1 criterion. Then if the area angle exceeds the threshold, emergency action to reduce the power flow through the area is recommended. Equally important is that if the area angle is less than the threshold, no emergency action is needed. This actionable information is obtained essentially by restricting the problem formulation to monitor and respond to the overloading problem associated with a particular power transfer through a particular area.

The standard way to compute effect of line outages inside the area is to perform state estimation in order to get a detailed description of the outages and individual line flows inside the area so that corrective actions can be taken as needed. Using the state estimator in this way is an accurate and useful procedure when it can be performed. The advantage of the area angle computation from PMU measurements is that it is faster, and available when the state estimator does not converge. This makes the area angle particularly appropriate when there are multiple simultaneous line outages that could cause further outages in a cascade. Multiple outages are the most difficult case for state estimation, and quickly determining whether emergency action is needed with the area angle based on PMUs is particularly useful in this case of potential further cascading. Since the area angle is a single bulk measure of the complexities of power flows and outages interacting

inside the area, it is an approximation. However, it appears to be a practical approximation that can give actionable information.

The area angle is calculated online from a weighted sum of the voltage phasor angles measured around the border of the area. This is a very easy and fast calculation. The weights are calculated offline from a DC load flow of the area. There is an assumed pattern of power flow through the area and positive weights correspond to buses which have power entering the area and negative weights correspond to buses which have power leaving the area or loads. The area angle is thus a bulk angle between buses on one “side” of the area to the other “side” of the area. Since the area angle is derived from circuit theory, it behaves intuitively when conditions change. If the power flow through the area increases by 10%, then the angle across the area increases by 10%. If there are line outages inside the area, then the power flow through the area is passing through an area of higher impedance and so the area angle increases. That is, even if the power flow through the area does not change much, the rerouted power flow through the area due to the line outages encounters more impedance, and so the area angle increases. This shows how the area angle responds to line outages inside the area, and how the area angle provides information not available from the bulk power flows into the area.

Previous work (with PSerc support) tested the area angle on the north-south transfer of power through Washington and Oregon states. One side of the area in which power flows into the area largely corresponds to the Canadian border and the other side of the area in which power leaves the area largely corresponds to the California-Oregon intertie. Thresholds for emergency action were computed and tested with multiple outages inside the area. For further practical applications of overload monitoring and mitigation with area angles computed from PMUs, it is important to define power system areas and their associated patterns of power flow in meaningful ways. That is, the area angle should be set up to monitor and mitigate a particular and salient pattern of power flow stress in the power system.

This project extends the area angle monitoring and mitigation to a different sort of area in which the power flows from the border of the area into large loads inside the area. Testing these new areas in Southern Idaho and in Southern California shows that emergency thresholds for area angle developed in relation to the N-1 criterion seem effective in discriminating the triple outages that require no quick action from those that require quick emergency action to curtail the power transfer. This new demonstration and testing of area angle extends the capability to combine PMU measurements into a scalar index to monitor a specific problem and determine if emergency action needs to be taken or not. This fast action based on PMU measurements is particularly useful for multiple contingencies when it is possible that the state estimator may not converge.

In order to work with these two new areas in the WECC region, we used a more detailed 19402 bus model of the WECC, and we refined the project modeling, software and algorithms to make them efficient enough to handle this detailed system model. One of the original project objectives was to redo the previous work on the north-south transfer through Washington and Oregon states with the more detailed model to assess the advantages or limitations of the detailed model versus a reduced model in this case. However, we were unable to get good results for the detailed model for this case. We also briefly assess the performance of the area angle when the power stress

direction varies. The case we tested showed considerable robustness to variation of the power stress direction.

The online calculation of the area angle, given the weights for combining the PMU measurements at the border of the area, are very easy and trivial. The offline testing of the area angle and the offline computation of the weights was performed in Mathematica software. This code is strictly research grade, but is available to PSerc members on request.

DOE project DE-0000849 “Real Time Applications Using Linear State Estimation Project (RTA/LSE)”, led by Electric Power Group LLC and subcontracting to Iowa State University pursues a practical industry demonstration of area angle monitoring with PMUs.

Part 2: A Structural Approach to Operations and Planning in the Changing Industry

The first section of Part 2 explains the broader context to the project work of needs and opportunities emerging in the changing industry. As the industry is changing, many solutions are being proposed. It has been difficult to put the specific methods into use. To cope with this problem, a unified approach is needed for modeling which supports extensions of current operating protocols to include and use fast measurements without data overload, and at value. There is also an overall context of an emerging broader framework for supporting interactions in complex electric power grids so that each group of grid users, and the grid itself, contribute to electricity service according with well-defined interactions and with a multi-layered modeling for future electric power grids. A transformed state space lends itself naturally to answering some key questions in this project, namely determining the minimum number of sensors (PMUs) and PMU-enabled actuators so that power transfers across area boundaries are stabilized in closed loop is achieved. It has been conceptualized how, instead of modeling system dynamics as a single "flat" model, interactions between components within an area; and interactions between areas within a region can be described by interaction variables. This concept could form the basis of next generation SCADA needed for PMU-based control without excessive complexity.

Placement of PMUs for enabling the best power delivery has a basic requirement of making the system dynamics observable. The second section of Part 2 describes the methods introduced to do this. Once the system dynamics are observable, one can begin to place actuators and protection to close the loop and ensure stable operation. An analogue method can be used to place actuators for fast closed-loop control. Ultimately, next generation SCADA emerges as a carefully selected fast communications scheme supporting fast control/protection that ensures no instabilities such as voltage collapse. We worked on graph methods for placing the PMUs and controllers so that the small signal stability of an electric power system is achieved. Theoretical work was done on structural controllability and observability conditions which can be used to select minimum number of locations and types of sensors and actuators to ensure stable operation.

The third section of Part 2 uses PMUs to control wind farms so that they can in an aggregated way provide power committed to the system operator. Specific control schemes of wind farms were introduced by incorporating feedback signals from PMU measurements, to enable them to regulate their power output to system-condition-dependent dynamic references. By meeting these power

references, the wind farms can contribute to guaranteed small-signal stability of the interconnected system while its loading conditions vary. This work shows how one may use PMUs to enable integration of renewable resources.

Project Publications:

- [1] Nipun Popli, Sergio Pequito, Soumya Kar, A Pedro Aguiar, and Marija Ilic. Selective strong structural minimum cost resilient co-design for regular descriptor linear systems. to appear in Automatica (arXiv preprint arXiv:1704.01157, 2017)
- [2] S. Pequito, N. Popli, S. Kar, M. Ilic, and A.P Aguiar. A framework for actuator placement in large scale power systems: Minimal strong structural controllability. In Proceedings of IEEE International Workshop on Computational Advances in Multi-Sensor Adaptive Processing, December 2013.
- [3] S. Baros, M. Ilic, Distributed Torque Control of Deloaded Wind DFIGs for Wind Farm Power Output Regulation, IEEE Transactions on Power Systems, Volume: 32, Issue: 6, pp. 4590 - 4599, Nov. 2017.
- [4] S. Baros, M. Ilic, A Consensus Approach to Real-time Distributed Control of Energy Storage Systems in Wind Farms, IEEE Transactions on Smart Grid, vol. PP, Issue: 99, pp.1-1, Sept. 2017

Student Theses:

- [1] Vikram K.R. Chiluka, *New areas for fast synchrophasor monitoring of multiple overloads with area angles*, Master's Thesis, Iowa State University, 2017.
- [2] Nipun Popli, *Multi-layered Energy Conversion and Frequency Control in Complex Electric Power Systems*. PhD Dissertation, Carnegie Mellon University, 2017.

Part I

Monitoring and Maintaining Limits of Area Transfers with PMUs

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1. Introduction

This report shows how to combine together synchrophasor measurements into a scalar area angle that quickly indicates whether multiple line outages require emergency action to reduce a specific power flow through the area to forestall line overloads. The state of the art is extended by setting up the area and the specific power flow in practical examples in which power flows into the border of the area and is consumed by loads inside the area. The advantages of using synchrophasor measurements in this way are their speed and their independence from state estimation. That is, the synchrophasor area angle can quickly recommend emergency action when needed, even if the state estimator fails to converge, as is possible when there are multiple outages. If the state estimator converges, then the area angle gives a fast indication that can be confirmed some minutes later with the more detailed conventional analysis based on state estimation.

The angle across an area of a power system is a weighted combination of synchrophasor measurements of voltage phasor angles around the border of the area [3, 7]. The weights are calculated offline from a DC load flow model of the area in such a way that the area angle satisfies circuit laws. Area angles were first developed for the special case of areas called cutset areas that extend all the way across the power system [4, 5, 6]. This was generalized to an area with power flow in one principal direction through the area as illustrated in Figure 1.1b and demonstrated with the north-south flow from Canada to California through an area that included Washington and Oregon states [10]. There are also AC versions of area angles [3, 15]. The area angle describes the stress on the area due to the power transfer, and an increase in the angle corresponds to increasing the loading of the area lines carrying the power transfer. (Since the area angle satisfies circuit laws, the intuition for this behavior is similar to the simple special case of two parallel circuits joining two buses: If one of the circuits outages, the total power flow transfers to the remaining circuit, but the angle between the two buses increases because the remaining circuit has higher impedance than the double circuit.) The purpose of setting up a specific area stressed with a specific power transfer from one area border to another area border is so that the corresponding area angle across the area and between those borders can be a meaningful scalar measurement for which thresholds for emergency action can be set.

For the area angle defined in [10], actionable thresholds for the area angle were developed so that the north-south power transfer could be quickly curtailed on an emergency basis if the area angle exceeded its threshold. This fast indication of the need for emergency action is particularly useful for multiple outages in which there is a possibility that the state estimator will not converge, so that the methods based on state estimation of detecting and mitigating line overloads are not available.

The new areas we introduce in this report consist of one boundary M_a enclosing the entire area and another boundary M_b formed by major loads in the middle of the area as shown in Figure 1.1a. The power flow pattern of interest is the import of power into the area through boundary M_a and its flow through the area to the loads M_b inside. This pattern of power flow stresses the area by loading its lines, and the area angle between M_a and M_b measures this stress.

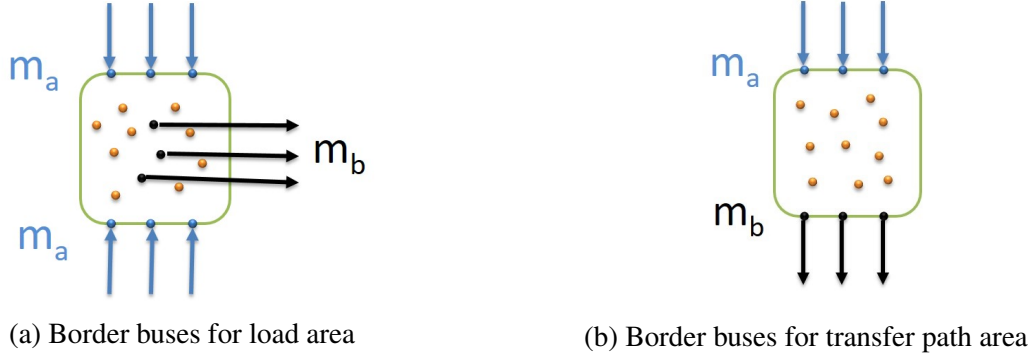


Figure 1.1: Border bus selection for different areas. Power enters the area in the border buses in M_a and leaves the area in border buses M_b .

All the results are based on a 19402 bus, 2024 summer base case DC load flow model of the WECC system unless otherwise stated. Throughout the report, we do not address the line outages inside the area that island the area.

1.1 Objective

The angle difference between two buses indicate a stressed power system. But an area of a power system has many buses and looking at the angle difference between any two buses does not give actionable information of the stress in the system. We reduce the area to a single line and combine the synchrophasor measurements at the border buses of an area to form an area angle. The area angle is the angle difference between the two buses of the reduced network and gives the stress across the system. Thresholds can be set for the area angle to monitor multiple line outages inside the area.

The specific objectives of this report are the following:

1. Test the area angle for new types of areas
2. Check the robustness for different patterns of stress while setting up actionable thresholds.
3. Study the effects the detailed model has on the offline computation process and develop efficient algorithms for better computation.
4. Explore calculating the area angle and setting up the thresholds in a twenty thousand bus WECC system model.

1.2 Organization of report

The first chapter gives a brief introduction on the intuition behind area angle and the objectives of the report. Chapter 2 gives a detailed description of the calculation of area angles and setting up actionable thresholds for them for monitoring. Chapter 3 describes the detailed WECC model. Chapter 4 gives the simulation results for new areas, robustness to stress patterns, effects of exceptional outages and the effect of model detail. Chapter 5 concludes the report. The appendix describes improvements in modeling and computation.

2. Review of area angle

2.1 Calculation of area angle and power across the area

Area angle is a scalar quantity obtained from angle measurements from the Phasor Measurement Units (PMUs or synchrophasors) at the border buses of an area. These angle measurements from PMUs are combined in a linear combination with weights to give one area angle. (The detail description and calculation of the area angle is found in [1, 7]). This can be thought of as in effect reducing the area to a single transmission line and finding the angle across the line which gives us the stress across it.

After choosing the area of interest, the border buses of an area must be identified. The selection of border buses depends on the type of area and is described in section 2.2. The power entering into the area is the power flowing across the tie lines (tie lines which are outside the area), P_{tie}^m and the power injections at the border buses P^m . All the buses inside the area are reduced by the Kron reduction process. The power injections across the interior buses are also reduced by Kron reduction and replaced as power injections at the border buses P_{int} . Hence the total power into the reduced area is the sum of internal and external powers:

$$P = P_{tie}^m + P^m + P_{int} \quad (2.1)$$

Now the reduced area consists of border buses and the lines connecting them as shown in figure 2.1. This network can be further reduced to a single transmission line. The power injections across its nodes P_{ab} is the sum of power injections across the border buses. The susceptance of the reduced line depends on the susceptances of the lines inside the network. Thus the value of susceptances changes whenever there is a change inside the network (For example outages of the lines inside changes the configuration of the network and changes susceptance of the reduced line). The angles at the border buses M_a have positive weights and angles at border buses M_b have negative weights. We assume angle measurements from synchrophasors are available at the chosen border buses of

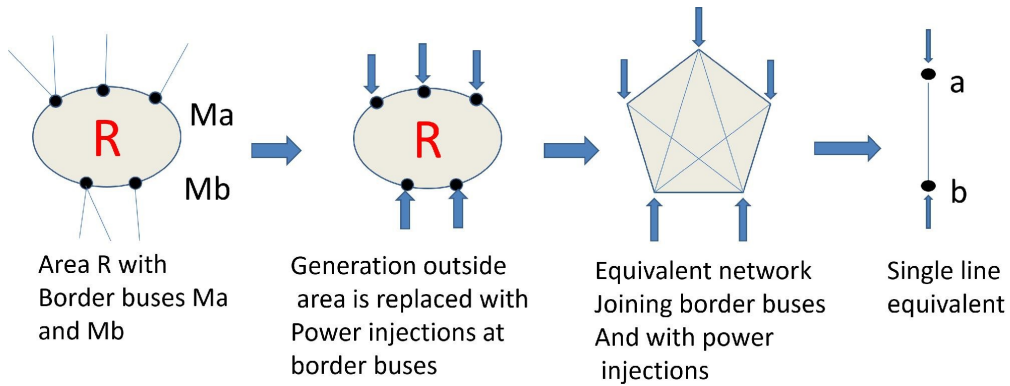


Figure 2.1: Area angle representation

an area. Area angle is computed as a weighted combination of angles across the border buses of an

area. If the border buses are ordered as $1, 2, 3, \dots, m$ and angles across these buses are $\theta_1, \theta_2, \dots, \theta_m$ then the area angle is computed as

$$\theta_{area} = \sum_{j=1}^m w_j \theta_j \quad (2.2)$$

$$w_j = \frac{\sigma_a B_{eq}}{b_{area}} \quad (2.3)$$

$$b_{area} = \sigma_a B_{eq} \sigma_a^T \quad (2.4)$$

$$\sum_{j=1}^m w_j = 0 \quad (2.5)$$

Here σ_a is the row vector of length m with entries of 1 at positions where there are M_a buses and the rest are zero. B_{eq} is the equivalent susceptance matrix of the border buses and b_{ab} is the bulk susceptance of the area. The power flow across an area is then

$$P_{ab} = b_{ab} \theta_{area} \quad (2.6)$$

2.2 Selection of border buses

The area angle calculation and maximum power that can enter the area depends on the susceptance of the area, which in turn depends on the configuration of the area chosen. Different configurations of the area can be obtained by choosing a different set of border buses and for each of these configurations, area angle will be different since the susceptances change. For the area angle to be calculated, the border buses of an area must be chosen in such a way that isolating the border buses disconnects the area from the rest of the network. In other words, the tie lines connecting the border buses must form a cutset.

The border buses of an area can be categorized into two sets. The first set of border buses must be chosen such that power entering into those buses along the tie lines must be positive. The second set must be chosen such that power entering those buses is negative. For example consider the BPA area (Figure 1.1b) which acts as a transmission corridor transferring power from northwest Canada to northern California. In this case northern border buses are named as M_a border buses and southern border buses are named as M_b border buses. For the load areas such as the southern California area (Figure 1.1a), the power is entering across all its outer border buses. In this case, all the outer border buses are selected to be M_a border buses and some load buses inside the area are selected to be M_b border buses. The choice of the M_b load buses depends on the availability of PMU measurements. Generally, electric utilities install PMUs at the largest load buses to monitor various parameters and hence we can select these buses to be M_b border buses.

2.3 The maximum power that can enter an area under single contingencies

Previous work uses area angle to define thresholds to monitor stress across the area under various contingencies [10] and showed that area angle is a good indicator of stress. The strategy is to define thresholds based on the line limits in terms of maximum power transfer through the area and convert the maximum power transfer threshold to an equivalent area angle threshold to monitor stress across the area. Then data from PMU are combined to measure the area angle and this area

angle is compared to the threshold. If the measured area angle is greater than the threshold, then it is an indication that the system is under stress and action is required.

To evaluate the maximum power that can enter the area it is necessary to stress the area with additional power injections [10]. These additional power injections can be made at border buses in proportion to the tie line flows entering or leaving at the border buses and in proportion to the net injection at the buses inside the area. That is, to find out the maximum power injection at the border buses we can inject the additional power at the border buses M_a and M_b .

To calculate the additional power injections, we first apply any contingencies by removing lines inside the area and then the DC power flow is calculated and the power flows through all the lines is determined. We need to calculate the amount of power that needs to be injected at the border buses such that line k reaches its limit in case of contingency i . The power injection is calculated from the generation shift factor as

$$\Delta P^{ab(i)kmax} = \frac{\Delta P_k^{limit(i)}}{\rho_k^{ab(i)}} \quad (2.7)$$

$$\rho_k^{ab(i)} = b_k(e_u^T - e_v^T)((B^i)^{-1})(e_a - e_b) \quad (2.8)$$

where $\Delta P_k^{limit(i)}$ is the difference between the power flow and its rated power flow in line k after contingency i . $\rho_k^{ab(i)}$ is the generation shift factor of the line k with respect to the power at border buses M_a . B_i is the susceptance matrix after line i is outaged, b_k is the admittance of the line i . u and v are the sending and receiving end buses of line k . For e_a , we can choose its entries corresponding to the M_a buses according to weights $\alpha_j, j \in M_a$ that are the fraction of power flows along the tie lines connecting the border buses:

$$\alpha_j = \frac{P_{intoj}}{P_{intoa}} \quad (2.9)$$

Similarly for e_b , we can choose $\alpha_j = \frac{P_{intoj}}{P_{intob}}, j \in M_b$. Alternatively, the weights can be chosen as the weights w_j used to define the area angle. These alternatives are discussed further in Chapter 4 of this report.

The maximum possible extra power injection into the border buses when line i is out such that the system satisfies the N-1 contingency criteria is the minimum of all additional power injection that satisfies all the line limits.

$$\Delta P^{inj} = \text{Min} \{ \Delta P^{ab(1)kmax}, \Delta P^{ab(2)kmax}, \dots, \Delta P^{ab(n)kmax} \} \quad (2.10)$$

If the power is injected at border buses M_a then the share of power injection at each border bus is

$$\Delta P_j = \alpha_j \Delta P^{inj} \quad (2.11)$$

Then the maximum power that can enter the area at border buses M_a is the sum of power across the cutset of lines joining the M_a border buses to the network outside the area and additional power calculated from equation 2.10 and the power injections at border M_a buses.

$$P_{ma}^{max(i)} = \Delta P^{injout} + \sigma_a P^{minto(i)} + P_{ma} \quad (2.12)$$

where $P^{minto(i)}$ is the sum of power flows through the M_a border buses when line i is outaged.

While calculating the area angle for different line outages, we do not consider the line outages which isolate the system when removed such as the radial distribution lines.

A threshold is set to be the area angle that occurs when the worst case single line outage happened. When area angle computed after other line outages is less than this area angle, then emergency measures should be taken to curtail the power transfer through the area.

2.4 Monitoring multiple outages

2.4.1 Simple example

Suppose the area is a transfer path area and power is transferred from north to south buses. Whenever a contingency happens, the power flow and voltage angles get redistributed. Whenever there is no path parallel to and outside the area, the tie flow into the area does not change. Whenever there is a high impedance path parallel to the area, the tie flow into the area does not change much. Hence, in these cases, the power entering the area is the same or approximately the same in both base case and in case of contingencies.

Consider the simple example of the case of three parallel lines connecting two buses as shown in Figure 2.2. The power entering the area is the same in all cases (base case and contingency

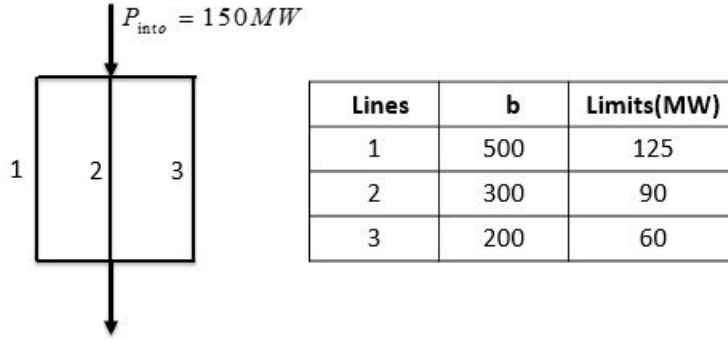


Figure 2.2: Simple example on monitoring multiple outages

cases).

Here we show in this simple example, the procedure to set up angle threshold to monitor multiple contingency cases.

Consider the case where line 3 is out. The powers flowing in lines 1 and 2 are 93.75 MW and 56.25 MW respectively. The maximum power that can enter into the area depends on the line limits and power flows. The additional power that should be injected at the north bus such that line 2 reaches its limit is 90MW ($\Delta P_{inj} = \frac{300}{800} = 90 - 56.25$). Therefore for line 2 to reach its limit, the maximum power that should be injected at the north bus is $P_{inj} = 150 + 90$. Similarly, for line 1 to reach its limit, the power that should be injected is $P_{inj} = 150 + 50$. Therefore, the maximum power that can enter into the area without violating the N-1 contingency criteria is minimum of the above maximum powers which is 200 MW. The area angle in this case is 10.74° . We can compute the maximum power that can enter the area and the area angle for the cases when lines 1, 2, 1&2, 1&3, 2&3 each outage and these cases are given in table 2.1

Table 2.1: Simple example demonstrating that area angle tracks severity

Lines	Base case			line 1 out			line 2 out			line 3 out		
	P	θ_{ab}	P_{max}	P	θ_{ab}	P_{max}	P	θ_{ab}	P_{max}	P	θ_{ab}	P_{max}
1	75		250	0		-	107.14		175	93.75		200
2	45	8.59°	300	90	17.18°	150	0	12.27°	-	56.25	10.74°	240
3	30		300	60		150	42.86		210	0		-
		8.59°	$P_{max}^{min} = 250$		17.18°	$P_{max}^{min} = 150$		12.27°	$P_{max}^{min} = 175$		10.74°	$P_{max}^{min} = 200$
			lines 1 & 2 out			lines 1 & 3 out			lines 2 & 3 out			
Lines	P	θ_{ab}	P_{max}	P	θ_{ab}	P_{max}	P	θ_{ab}	P_{max}	P	θ_{ab}	P_{max}
1	0		-	0		-	150		-25			
2	0	42.97°	-	150	28.64°	-60	0	17.18°	-			
3	150		-90	0		-	0		-			
		42.97°	$P_{max}^{min} = -90$		28.64°	$P_{max}^{min} = -60$		17.18°	$P_{max}^{min} = -25$			

From table 2.1, we can see that in the case of single line outages, as the maximum power that can enter the area decreases from 250 MW to 150 MW, the area angle increases from 8.59° to 17.18°. Similarly, for double line outages, the maximum power that can enter the area decreases from -25 MW to -90 MW, thus effectively violating the N-1 contingency criteria. The area angle in this case increases from 17.18° to 42.97°.

The area (Figure 2.2) is designed such that it follows N-1 criteria. Now, we set the maximum power entering the area in the worst case single contingency to be the emergency power threshold. Since the maximum power is a hypothetical quantity and cannot be monitored, we convert the maximum power emergency threshold to emergency area angle threshold. The area angle can be computed from the measurements of synchrophasor data available at border buses.

Following the procedure, we set the emergency power threshold in the simple example (2.2) to be 150 MW i.e., the worst case single contingency happens when line 1 is out and the corresponding area angle is 17.18°. We choose this area angle to be emergency area angle threshold. We can see that, in case of multiple outages, the area angle is always above the emergency area angle threshold, thus effectively indicating that multiple outages inside the area are worse than the worst case N-1 case, and require emergency action to reduce the transfer through the area.

2.4.2 Algorithm

We now summarize the area angle algorithm from [10].

Offline calculations

1. Choose the border buses of an area such that the border buses form a cutset (section 2.2).
2. For each single outage inside the area, after the outage, calculate the maximum power that can enter the area before the first line limit is encountered. The maximum power that can enter the area for the worst case single outage is the emergency threshold for the maximum power entering the area. Also define the alarm threshold on the maximum power entering the area.

3. Set the base case power entering the area to the emergency threshold of the maximum power. Then for all single outages inside the area, calculate the area angle after the outage.
4. After eliminating the exceptional outages, choose the minimum of all the maximum powers from step 2 as the emergency power threshold (This is because this is the maximum amount of power that can enter into the area under worst case single contingency without violating N-1 contingency criteria). The corresponding area angle will be emergency area angle threshold.

Online implementation

1. Continuously observe the system using synchrophasors at the border buses. Get the values of voltage angles from the synchrophasors in real time.
2. Calculate the area angle using the weights computed offline.
3. If outages which are causing local power redistribution problems have not occurred, then compare the area angle to its thresholds to take no action or to take proper action with the appropriate urgency.
4. If the area angle is above the emergency area angle threshold (it implies that the multiple outages are worse than worst case single line contingency and not following the N-1 criteria), then take emergency actions to reduce the power in the tie lines of the area.

2.5 Exceptional outages

It is not always the case that the area angle is inversely related to the maximum power that can enter the area. In our experience we encountered some cases in which there are exceptional outages for which the area angle does not necessarily track the maximum power that can enter into the area. In [10], Darvishi explained one illustrative example of an exceptional outage where the area angle increases but the maximum power entering the area remains the same for the simple network of Figure 2.3. Here we show additional cases by changing the susceptance and line limit values for the same illustrative example.

The various possibilities of exceptional outages are given in table 2.2. In order to explain all

Table 2.2: The possibilities of exceptional outages

P_{into}^{max}	θ_{ab}
Decreases	Constant
Increases	Constant
Constant	Decreases
Constant	Increases
Decreases	Decreases
Increases	Increases
Constant	Constant

the possibilities of exceptional outages in table 2.2, consider the following network in Figure 2.3.

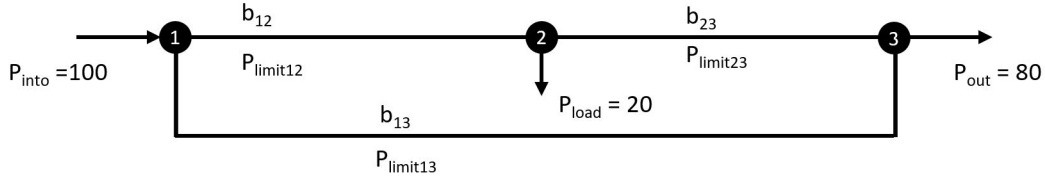


Figure 2.3: Simple network for illustrating exceptional outages

The line limits are chosen such that the network satisfies the N-1 criteria. In this network the power entering into the area (bus 1) is 100 pu and is always the same in base case and in case of contingencies. However, the maximum power that can enter into the area changes. The power out is 80 pu and load is 20 pu in all the cases. By changing the limits and susceptances of the lines inside the area, we can demonstrate all the possible exceptional cases as shown in table 2.3. The single line outages which are not following the inverse relation are exceptional outages. This more general analysis of exceptional outages should be useful in understanding cases in which the area angle does not work as expected.

Table 2.3: Exceptional outages in simple network

$P_{limit12}$	b_{12}	$P_{limit13}$	b_{13}	$P_{limit23}$	b_{23}	line 1-2 out		line 1-3 out		P_{into}^{max}	θ_{13}
						P_{into}^{max}	θ_{13}	P_{into}^{max}	θ_{13}		
100	40	100	30	80	20	100	3.3	100	6.5	constant	increase
100	50	120	30	80	60	120	3.3	100	3.3	decrease	constant
100	50	120	20	80	60	120	5	100	3.3	decrease	decrease
100	50	100	20	80	60	100	5	100	3.3	constant	decrease
120	50	100	30	100	60	100	3.3	120	3.3	increase	constant
120	40	100	30	100	20	100	3.3	120	6.5	increase	increase
100	50	100	30	80	60	100	3.3	100	3.3	constant	constant

3. Description of power system network model

The data used for modeling and simulation is the North American Western interconnection (WECC) system. The details and the difference between reduced and detailed model are given in table 3.1. The network formed is given in Figure 3.1. The top part of the graph corresponds to those buses

Table 3.1: Difference between the detailed and reduced models

	Detailed model	Reduced model
Number of buses	20194	1553
Number of loads	10951	898
Number of transmission lines	16912	2115
Number of generators	4254	493
Number of two winding transformers	7654	243
Number of three winding transformers	561	0
Number of HVDC lines	3	0
Number of areas	239	64

which are in Canada followed by those buses which are in Washington, Montana, Oregon, Idaho, Nevada, Utah, Colorado and the bottom part of graph corresponds to buses which are in southern California, Arizona. The DC load flow voltage angle is computed for all the buses in the network and these are shown by the colors in Figure 3.1. It can be seen that angle is higher at northern buses and tends to reduce as one progresses towards the south, indicating that power is transferred from northern part of Washington state (where there is generation available) to load parts such as south western part of California (where there are major load centers) with some power consumed in between. In this report, we explain the area angle concepts on Southern California region and Southern Idaho region that are essentially load areas, and the BPA area which covers the states of Washington, Oregon and part of Idaho. The BPA area acts as transmission corridor transferring power from Canada to California.

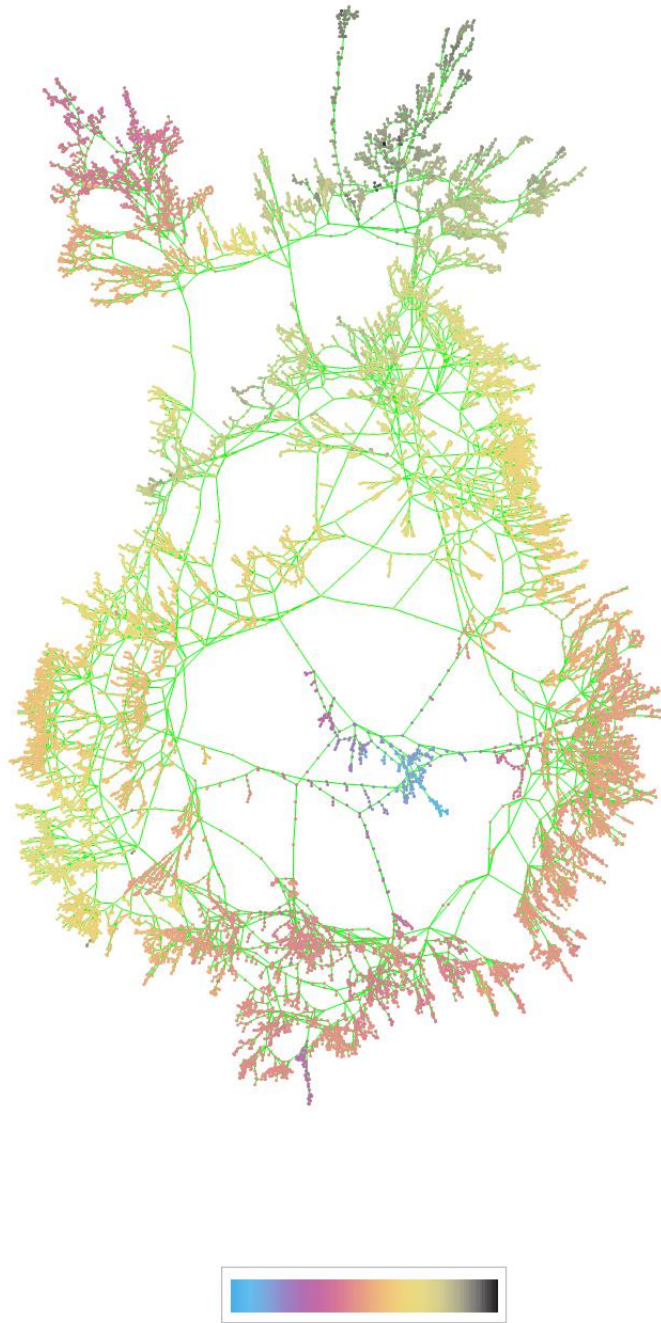


Figure 3.1: Angles at the buses plotted on a 19402 bus WECC model. The black color represents a higher value and blue color represents a lower value. Layout is not geographic.

4. Areas, area angles and thresholds

We calculated the area angle and set the thresholds on area angles for three different areas. Two areas in Idaho and in Southern California are load areas. The third area is a transmission corridor through the states of Washington and Oregon supplying power from Canada down to California.

4.1 Southern Idaho area

The Southern Idaho area is a load area, where the power is consumed inside the area. According to the model, it has about 271 buses and 312 transmission lines. The Idaho area is given below with the M_a border buses colored in red and M_b border buses colored in blue and all the other buses inside the area are colored in black. The numbers across the border buses represents the weights at those buses.

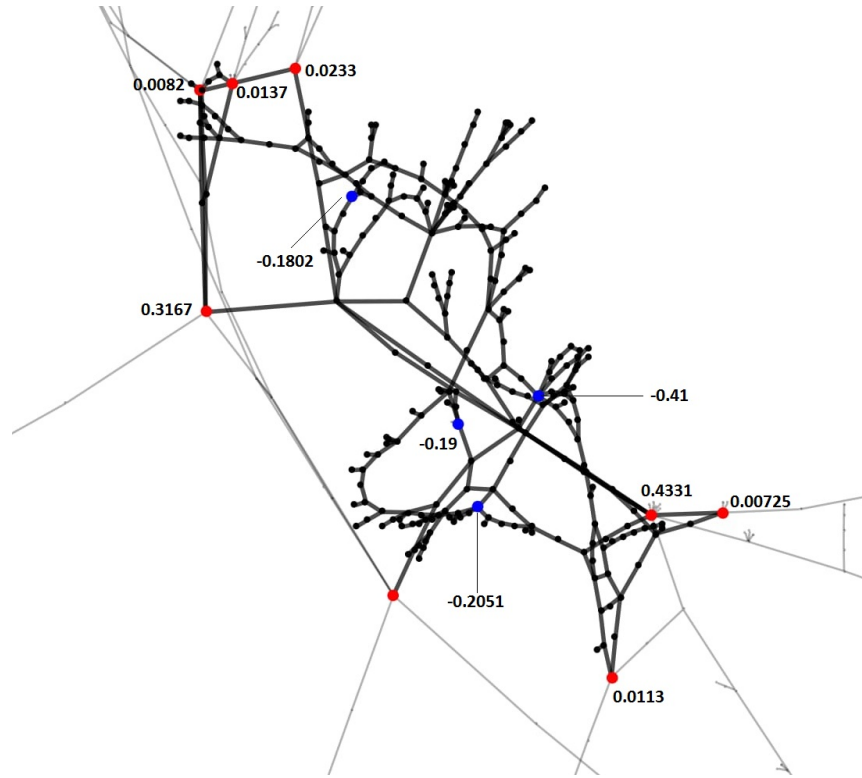


Figure 4.1: Southern Idaho area: Border M_a buses are colored in red and border M_b buses area colored in blue. Numbers represent the weights

4.1.1 Outages and the calculation of thresholds for area angle

All the lines inside the area are simulated to be outaged one at a time and after removing the exceptional outages, the results are plotted below. The minimum of the maximum powers that can enter the area is 33.2 pu with corresponding area angle 9.93 deg. So, the emergency threshold in this case will be 9.93 deg. (We do not set any alarm thresholds in this case as in [10] as the slope

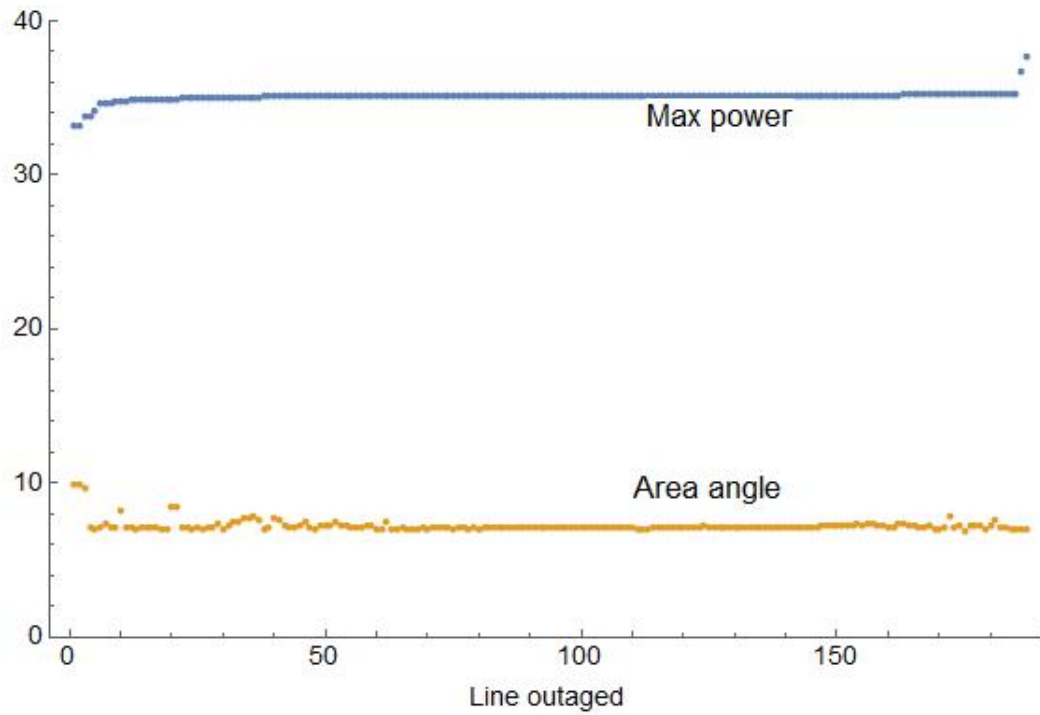


Figure 4.2: Single line non-exceptional outages for Southern Idaho area. Outages are ordered so the maximum power increases.

of the maximum power is not clear.) The double and triple outages are given below after excluding the exceptional outages. We can see that the area angle emergency threshold discriminates the double and triple outages that have powers less than the emergency power threshold.

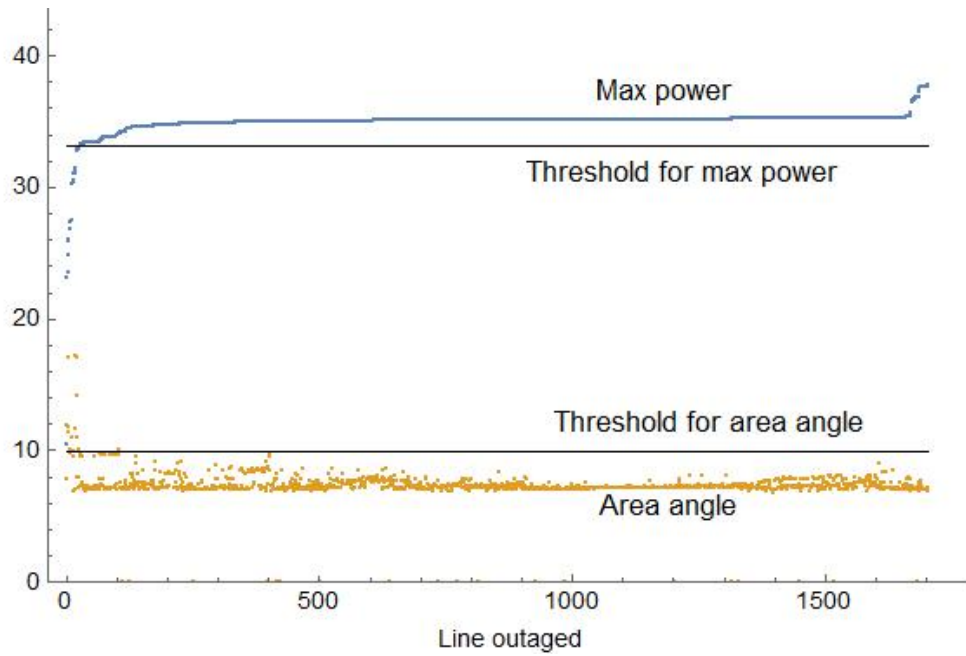


Figure 4.3: Random sample of 1700 double line non-exceptional outages for Southern Idaho area

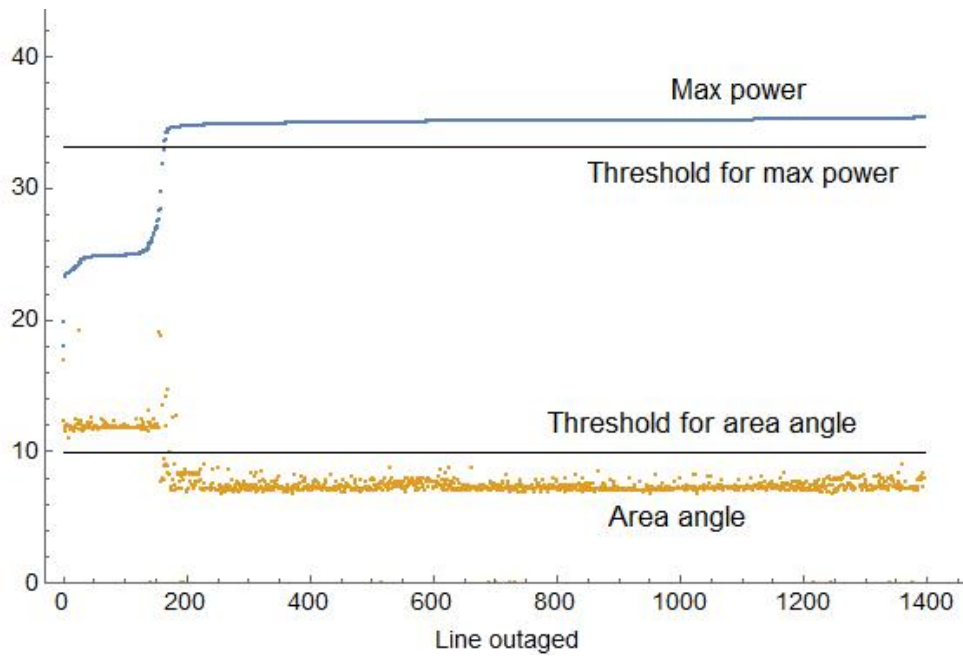


Figure 4.4: Random sample of 1396 triple line non-exceptional outages for Southern Idaho area.

4.2 Southern California area

The Southern California is a load area with power transferred through an outer border and consumed inside the area. The Southern California area network buses and transmission lines are shown in Figure 4.5.

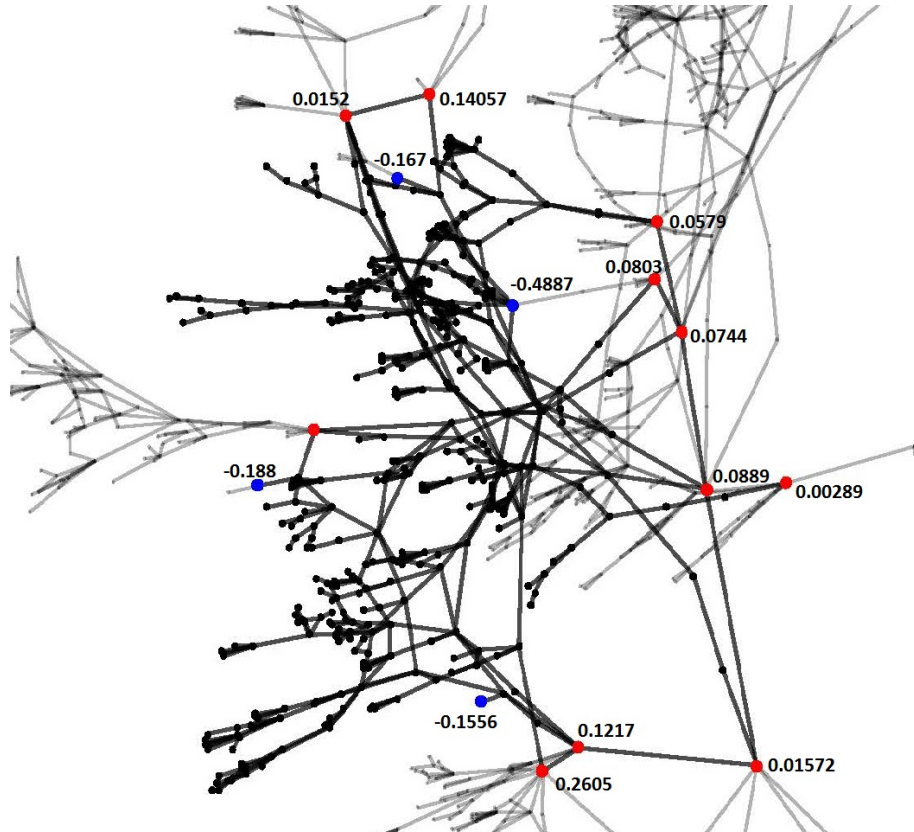


Figure 4.5: Southern California area

One pattern of bulk power flow through the Southern California area transfers power from the outer border of the area to Los Angeles. This bulk power flow is limited by maximum power flow limits on the transmission lines. Under normal operation, there is considerable margin available for this power transfer. Single contingencies reduce but do not eliminate this margin, and in this case state estimation can generally identify the contingency and converge to give the flows on all the remaining lines and identify any corrective actions necessary. In rare but consequential cases, there can be multiple outages, and in this case the state estimator may or may not converge, but there is always a need to quickly discriminate whether fast emergency action to reduce the power transfer is necessary or not.

The Southern California area consists of Los Angeles and regions surrounding Los Angeles and is shown by the darker buses and lines in Figure 4.5. The Southern California area network has 418 buses and 501 lines. Red buses in Figure 4.5 represent the outer border buses and blue buses are major loads in Los Angeles. The weights used to compute the area angle are shown in Figure 4.5 and are calculated offline and updated occasionally. Given the weights and the availability of

the synchrophasor measurements at the specified buses, the online calculation of the area angle from the synchrophasor measurements using the weights is trivial. In practical application, we can expect some simplification and reduction in the measurements required. It may be possible and desirable to omit measurements with small weights, or to approximate a lower voltage bus measurement by a constant angle difference from the higher voltage bus in the same substation or close by.

Here we are assuming synchrophasor measurements are available at the specified buses. As of 2010, synchrophasors were installed or proposed at all the border buses except for one of the load buses. The trend is for synchrophasor measurements to become more widespread, particularly as modern relays can include synchrophasor measurements. We note in computing the area angle that border buses with very small weights can be omitted from the calculation so that synchrophasor measurement at those buses is not required.

4.2.1 Outages and area angle thresholds

The single line outages are given below.

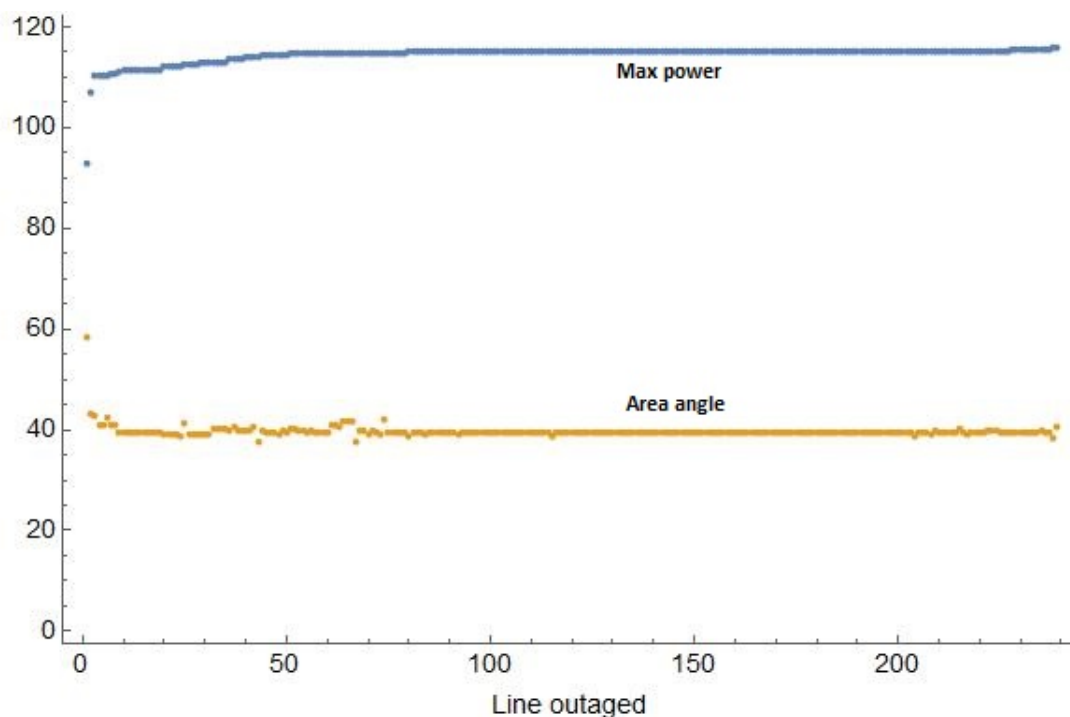


Figure 4.6: Single line non-exceptional outages for Southern California area. Outages are ordered so that maximum power increases

The power entering the area during the worst case single contingency is approximately 93 pu and the corresponding area angle is 58 pu (approximately). The double and triple outages are given below with the emergency thresholds for area angle and max power and it can be seen that the thresholds clearly detect the double and triple outages which are worse than worst case single contingency.

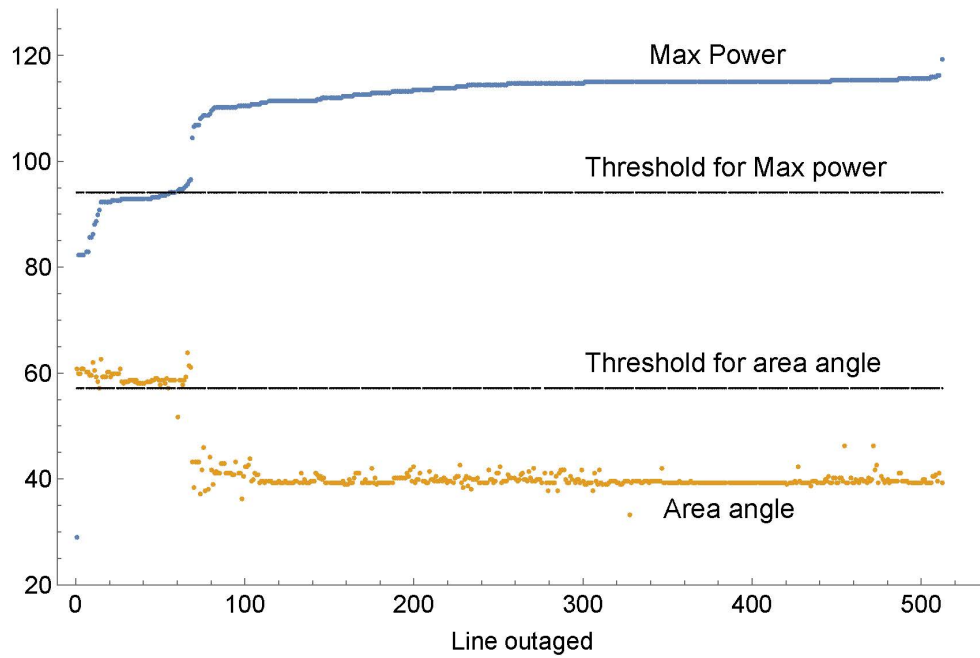


Figure 4.7: Random sample of 512 double line non-exceptional outages for Southern California area.

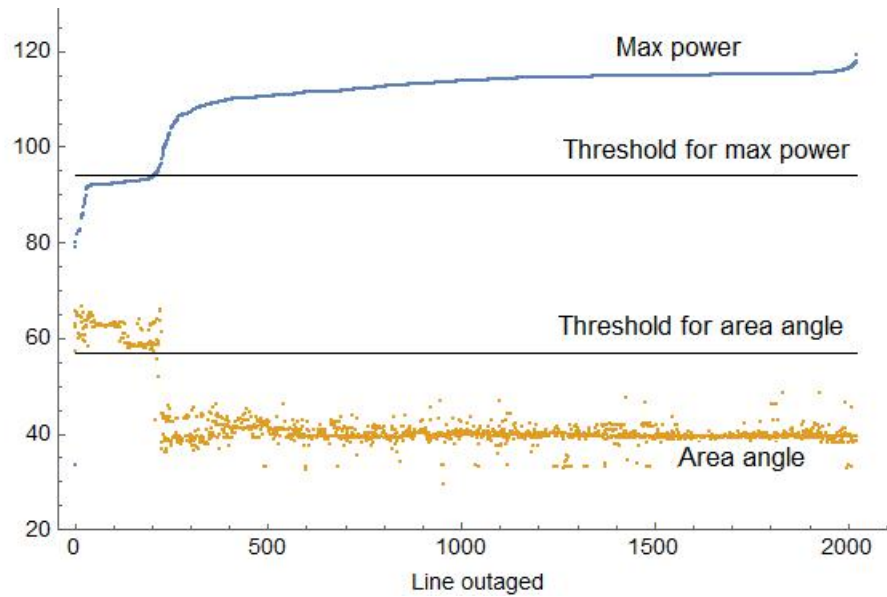


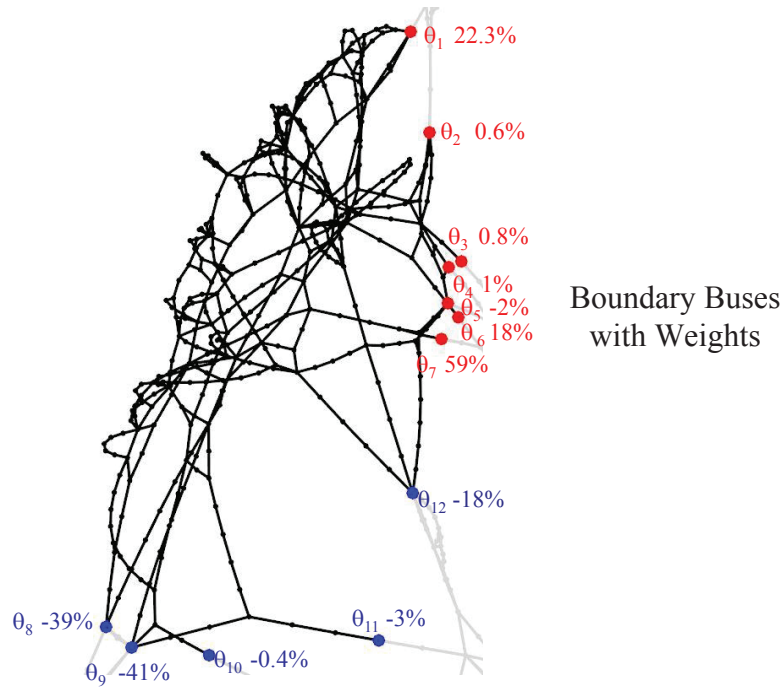
Figure 4.8: Random sample of 2020 triple line non-exceptional outages for Southern California area.

4.3 BPA area

Unlike Idaho and Southern California areas, which are load areas, the BPA area acts as a transmission corridor sending power from Canada in the north to California in the south. The border

buses form a minimal cutset of the network and are shown in Figure 4.9. This BPA network has 407 buses and is formed from a reduced 1553 bus WECC network and is the same area studied in [10],

We also worked on a much more detailed model of the BPA area consisting of 3737 buses and 4271 lines, but were unable to get satisfactory results.



8

Figure 4.9: BPA area in reduced WECC network

4.4 Robustness to changing stress direction

When determining the area angle thresholds, it is necessary to choose a pattern of stress by which the power transfer is increased. When a line is out, the participation factors for all the remaining lines are calculated with respect to power injections at the border buses. The maximum power that can be injected across the border buses such that line k inside the area reaches its limit is obtained by dividing the limit of that line by its participation factor according to equation (4) in [10]. Then the amount of power to be injected into the border buses is the minimum of injections across all the lines. The amount of power to be injected at the border bus such that line k reaches its maximum power limit depends on the generation shift factor of line k . According to equation (8) in [10] the generation shift factor for line k with respect to injections at border buses is given by

$$\rho_k^{ab(i)} = b_k(e_u^T - e_v^T)((B^i)^{-1})(e_a - e_b)$$

Here e_a and e_b are $n \times 1$ vectors (n is the number of buses) with values only at the positions of border buses and the rest are zero. We choose the values in these column vectors to specify the pattern of stress. The first method is to choose e_a and e_b according to the weights at the buses. The second method chooses e_a and e_b according to $\alpha = P_{intoj}/P_{intom}$. The pattern of stress is defined by how the border buses participate in changes in the power transfer.

We compare these two different methods of stressing each area to assess the robustness of the thresholds when the power stress pattern is changed.

1. The first method increases the power at border bus i proportional to the power injected at border bus i from outside the area.
2. The second method increases the power at border bus number i proportional to the area angle weight w_i .

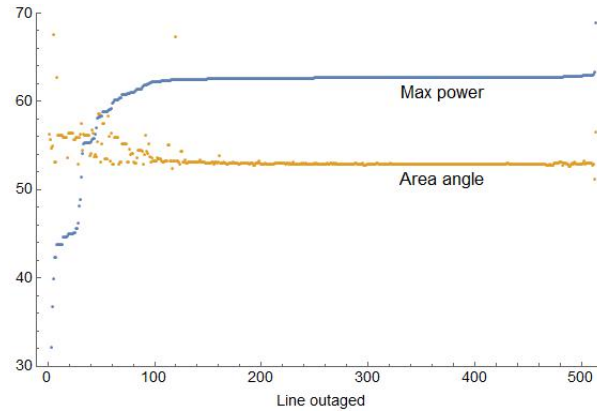


Figure 4.10: Single line outages for reduced BPA network. Pattern of stress used here is according to weights at the buses

Here we compare the single line outages of BPA network in a reduced network. Single line outages for the reduced BPA area from [10] is reproduced here for easy reference in Figure 4.10.

The outages are ordered according to increasing amount of maximum power transfer into the area. The results in [10] for the north-south transfer of power through the BPA area are obtained with the second method, so here we give the results for the first method¹. The weights at the border buses used for stressing the system in [10] are

$$w = \{0.23, 0.0057, 0.0078, 0.1, 0.18, 0.017, 0.6, -0.03, -0.4, -0.38, -0.18, -0.004\} \quad (4.1)$$

The weights at the border buses which are proportional to tie line flows are

$$\alpha = \{0.68, 0.0111, 0.002, 0.056, 0.019, 0.042, 0.18, -0.002, -0.4, -0.35, -0.23, -0.029\} \quad (4.2)$$

We note the substantial difference in the weights in (4.1) and (4.2).

The single outages of the system stressed according to α are given in Figure 4.11. Comparing Figure 4.11 with Figure 4.10 we can see that the results are similar and the thresholds do not depend on the method of stress.

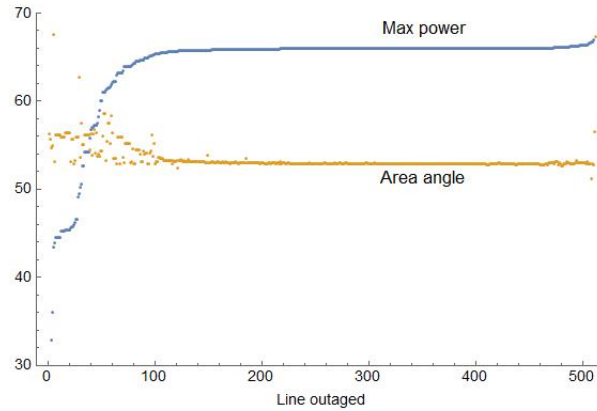


Figure 4.11: Single line outages for reduced BPA network. Pattern of stress used here is proportional to the tie line power flows into the buses.

4.5 Effect of exceptional outages

The formulation of the areas is such that power enters into the area through one set of border buses and transfers or get consumed at the other set of border buses. The radial lines inside the area do not participate in the power transfer. The meshed lines in the area can participate in the power transfer. There is a general tendency for an outage of one the meshed lines to decrease the maximum power that can be transferred through the area, since the outage tends to transfer more power to the parallel paths. Moreover, the outage tends to increase the impedance across the area while the power transfer remains constant. Since the area angle obeys circuit laws, it follows that the area angle generally increases. Thus there is generally an inverse relationship between area angle and

¹The first method is described by equation (8) of [10]. However the results presented in [10] tacitly use the second method.

maximum power transfer that we exploit in the monitoring. However, there are some exceptional cases in which the area angle does not respond inversely to the maximum power transfer. These exceptional cases usually correspond to local power redistribution problems as explained in [10] and further in Chapter 3 of this report. Depending on the nature of the lack of response, some of the lines giving exceptional outages need to be independently monitored to improve the accuracy of the interpretation of the area angle changes. Figure 4.12 shows all the single line outages for the Idaho area, including the exceptional outages shown as red dots. Figure 4.13 shows all the triple line outages for the Idaho area that include at least one exceptional outage.

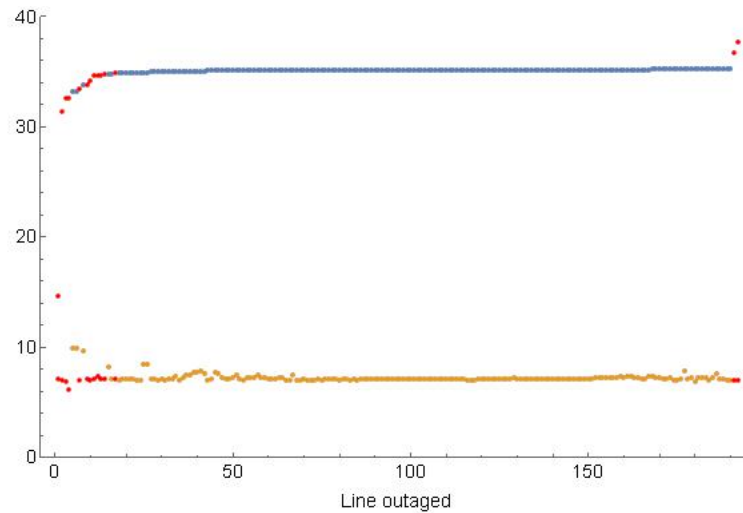


Figure 4.12: All single line outages for Idaho area with exceptional outages colored in red

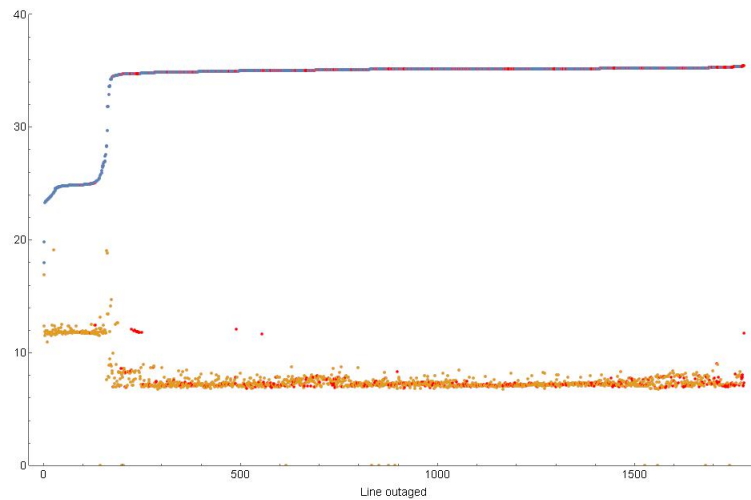


Figure 4.13: Random sample of triple line outages for Idaho area with exceptional outages colored in red

4.6 A perspective from interface power flow limits

Area angle is an approach to monitoring and mitigating overload limits with a scalar bulk measurement. It provides a fast but approximate PMU-based alternative to detailed methods of monitoring each line via state estimation that can function for multiple contingencies when the state estimator does not converge.

A conventional scalar bulk measurement approach to system limits uses interface power flow limits. Interface definition is created by using offline studies and “engineering experiences”. That approach works reasonably well for stable power flow patterns. Today, the interfaces defined in this static way become less efficient and there are good chances that the interface-based approach could be too optimistic or/and too conservative. Thus as power flow patterns become more varied, interface limits need to be computed more dynamically.

Similar considerations should apply for area angles. Several different area angles (for different patterns of flow across the same area or for different areas) may need to be developed, one for each pattern of power flow. While it seems that a choice of several relevant area angles could be made using the approach of this report and engineering judgment, it seems that we do not yet understand forming meaningful areas well enough to make feasible automatically and dynamically forming areas and their angles. This could be considered in future work. However, while dynamically varying limits are useful from a operations/security prospective, they are less desirable from a market perspective because the market needs a long term “monetary feedback” and a dynamic interface cannot provide that.

It is also interesting to compare interface power flow limits with area angles. There is a fundamental difference between a flow variable such as power through an interface and a voltage difference variable such as an area angle. (They are of course related via Ohm’s law.) Area angles react to contingencies differently than interface power flows, since line outages often just redirect the same power flows to parallel paths, whereas the angle responds to the increased impedance the power is flowing through. The power industry probably developed using interface power flow limits because the power could be readily measured. Now that PMUs are becoming widespread, the different possibilities of area angles can be also be pursued.

One of the interesting heuristics for forming meaningful areas is to assemble the approximate border of the area from key interfaces already established in the power system. Either the interface has to be a closed interface already surrounding the area or it has to be assembled from open interfaces so that they completely surround the area. This type of area can help to show how the concept of interface power flows relates to the concept of area angles.

In future practical applications, the strict requirement that the border buses of the area form a nodal cutset entirely separating the area from the rest of the network may need to be relaxed a bit, mainly because of PMU availability. While the relevant PMUs are often available at medium and high voltage buses, in order to strictly form a cutset, it is sometimes necessary to choose lower voltage buses as border buses. Some of these low voltage border buses will tend to be connected to high impedance lines that can cause their weights to be small or negligible, and approximations can be made with little error in the area angle response. For example, one can either use nearby PMU measurements (which can be further adjusted with the typical average difference between their angles if needed) or one could use more elaborate statistical methods to estimate the voltage angle at the missing PMU buses. These approaches should be explored in future work.

5. Conclusion

Our overall philosophy to extract actionable information from synchrophasor data is to restrict the problem to one pattern of stress for one phenomenon, and suitably combine data from multiple synchrophasors into a meaningful scalar to be monitored. This restriction of the problem then allows not only detection of emergency conditions when the scalar exceeds a threshold, but specific mitigation actions to correct the problem. In particular, we use an area angle to monitor a specific power transfer through a specific area with respect to thermal limits.

To advance and make workable this philosophy for area angles monitoring thermal limits inside an area, it is necessary to develop the art of choosing areas and power transfers stressing these areas, and show that meaningful thresholds can be developed. In this report, we extend the area angle monitoring to a different sort of area in which the power flows from the border of the area into large loads well inside the area. The emergency thresholds for area angle developed in relation to the N-1 criterion seem effective in discriminating the triple outages that require no quick action from those that require quick emergency action to curtail the power transfer.

We also briefly assess the performance of the area angle with respect to power stress direction. We have a choice of stressing the system either according to the weights or according to the proportional tie line power flows. The maximum power that can enter the area remained the same irrespective of the type of the stress and the emergency thresholds that are setup discriminates the multiple outages.

The time required to run the offline algorithm of calculating and setting up the thresholds will be in the magnitude of days if computed by brute force methods. The techniques introduced helped achieve computational efficiency. After employing these techniques, the time required for offline algorithm varies from hours to days depending on the size of the area. The offline calculations that calculate the weighting for the angles were improved to be practical for large system models, but there is room for further improvement in calculation efficiency. Online algorithm calculations are very fast since the computation is trivial and they use phasor voltage angle measurements from the synchrophasors at the border buses of the area.

Our testing of area angle extends the capability to combine synchrophasor measurements into a scalar index to monitor a specific problem and determine if emergency action needs to be taken or not. This fast action based on synchrophasor measurements is particularly useful for multiple contingencies when it is possible that the state estimator may not converge. In particular, we have shown that an area angle that suitably combines synchrophasor measurements can monitor a specific power flow through a power system area, and that a threshold on the area angle for emergency action to reduce the power flow can be set so that multiple line outages that are more severe than the worst case single line outage can be quickly distinguished. The area angle leads to actionable advice because it is associated with a particular pattern of power flow, and that is the power flow that would be curtailed if the area angle exceeds its threshold. The online calculations combining the synchrophasor measurements are fast and the monitoring and actions would be independent of the state estimator. The area angle is based on circuit theory and reacts intuitively in a way that is analogous with the angle difference across a transmission line. The area angle

is not perfect (there are some exceptional cases of line outages for which the area angle does not suitably respond), but it is one of the few methods that goes beyond monitoring to yield actionable information based on synchrophasor measurements.

A. System modeling and computation

As described in the previous chapters, all the simulations are run on a twenty thousand bus Western Interconnection (WECC) system and all the calculations are done using Mathematica software. This chapter describes the modeling and steps to improve the computational efficiency. The data available for simulation is in the PSLF epc format. We have the choice of running DC load flow either in PSLF or PSSE software and export the necessary details for further calculations in any format supported by Mathematica. Since we have the framework set up to read PSSE .raw file format in Mathematica, we exported the .epc file as a .raw file.

A detailed system is always challenging in terms of modeling, computational efficiency, data analysis etc. Techniques are employed to reduce the computational time and memory required for computations. In the offline calculations testing area angle and setting thresholds, line outages have to be simulated. Whenever a line is out, the network topology changes and the susceptance matrix changes. In the calculation of participation factor, inverse of susceptance matrix is used as shown in equation 2.8. The network has 20000 buses, so the susceptance of network is a matrix with 20000 rows and 20000 columns. Inverse calculation of such a matrix involves huge computational time and memory. We use the matrix inversion lemma to calculate the inverse of such a huge matrix and this is further explained in section A.5. We achieved better computational time efficiency by utilizing many of the inbuilt functions in Mathematica. The computational time and memory required to simulate the area depends on the size of the area.

A.1 Branches

The DC power flow is given by the equation

$$P = B\theta \quad (\text{A.1})$$

where $P_{n \times 1}$ is the column vector of power injections at the n buses, $\theta_{n \times 1}$ is a column vector of voltage angle at the buses, and $B_{n \times n}$ is the admittance matrix where

$$B_{ii} = -\sum_{n=1}^k b_{in} \quad (\text{A.2})$$

$$B_{ik} = -b_{ik} \quad (\text{A.3})$$

and b_{ik} is the susceptance of the line joining bus i and bus k . In the DC load flow, all the branches are considered lossless. Therefore all the two winding transformers and transmission lines are represented with series impedance $z = r + jx$, $b = \frac{-1}{x}$.

A.2 Three winding transformers

A three winding transformer modeling is different from a two winding transformer. While modeling a three winding transformer, we have the choice of a three bus equivalent model or a four bus equivalent model as shown in Figure A.1. In the three bus model, the three winding transformer is split into two transformers. It does not consider the impedance of primary winding. In the four bus equivalent, it is split into three two-winding transformers. For the DC load flow calculation,

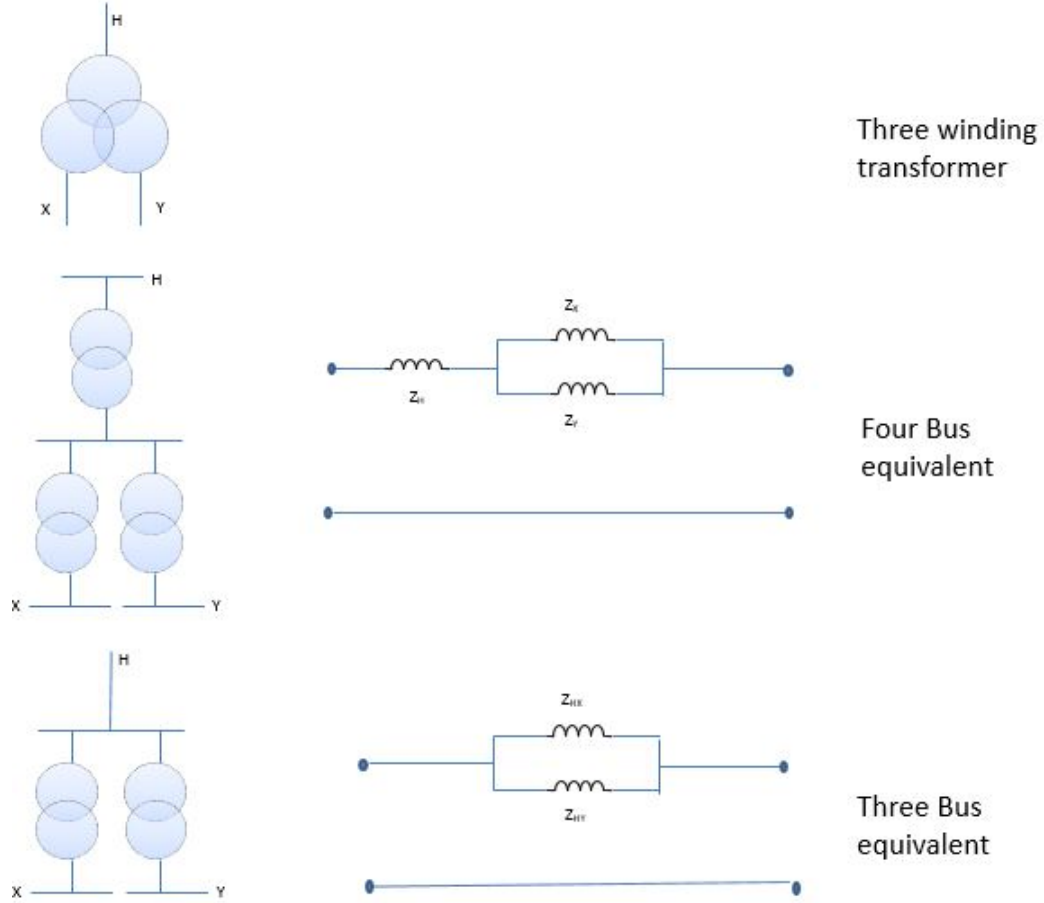


Figure A.1: Modeling of three winding transformer

the primary impedance can be ignored. Therefore, for the DC load flow calculations, the three bus equivalent is used to model the three winding transformer.

A.3 HVDC lines

In the western interconnection, there are three HVDC connections

1. Eastern Alberta Transmission line, which is 485 km long interconnecting Newell HVDC static inverter plant near Brooks, Alberta with Heathfield static inverter plant near Gibbons, Alberta.
2. Pacific DC Intertie, also called Path 65, is 846 miles long interconnecting Celilo converter station in Oregon to Sylmar converter station north of Los Angeles.
3. Intermountain HVDC power line, also called Path 27, is 488 miles long interconnecting Adelanto converter station in Adelanto, California to Intermountain converter station in Delta, Utah.

In order to model the HVDC lines, we remove power from those buses where HVDC power is injected and add power to those buses where HVDC power is extracted. In other words, if P_{dc} is

the amount of power that is transferred through the HVDC line from bus a to bus b , then at bus a , the injection will be $-P_{dc}$ and at bus b , the injection will be P_{dc} .

A.4 Participation factor calculation

The area angle computation and the setting of area angle threshold helps us discriminate the double and triple line outages which are comparable to worst case single line outage. The shift factor of each line inside the area with respect to the border buses of the area is given by equation (2.8), which is copied here as

$$\rho_k^{ab(i)} = b_k(e_u^T - e_v^T)((B^i)^{-1})(e_a - e_b) \quad (\text{A.4})$$

Here e_a and e_b have nonzero entries corresponding to buses M_a and M_b . e_u and e_v have entry 1 at the starting bus position and ending bus position of line k respectively.

After choosing a particular area, the values and positions of elements in the column matrices e_a and e_b do not change since they are ratios of base power injections at the border buses. The values of row matrices e_u^T and e_v^T do not change but the positions change according to the starting and ending buses of line k . However, these positions are within range of buses in the area since the area angle is computed only for the chosen area and all the values at the positions outside the range of area buses are zero. The structure of the matrices is given below

$$e_u^T - e_v^T = [0 \ 0 \ \dots \ 0 \ v_1 \ v_2 \ \dots \ v_k \ 0 \ \dots \ 0 \ 0]$$

$$((B^i)^{-1})(e_a - e_b) = \begin{bmatrix} x_1 \\ x_2 \\ \vdots \\ x_n \end{bmatrix}$$

$$(e_u^T - e_v^T)((B^i)^{-1})(e_a - e_b) = 0 * x_1 + 0 * x_2 + \dots + v_1 * x_{b1} + v_2 * x_{b2} + \dots + v_k * x_{bk} + \dots + 0 * x_n$$

From the above equations, we can see that in the participation factor calculation, only the elements of the *Binverse* matrix whose positions are within the range of area buses are required. Hence we can form a sparse *Binverse* matrix which has elements only in the range of buses of the chosen area and all other elements allowed to be zero. This not only reduces the memory to store the *Binverse* matrix but also increases efficiency in calculation of participation factor.

A.5 B inverse matrix calculation

To calculate the participation factor during single, double, and triple outages, it is necessary to calculate B_{out}^{-1} matrix for each outage i . We calculate the B_{out}^{-1} matrix from the matrix inverse

lemma.

$$e_{ij} = \begin{bmatrix} 0 \\ \vdots \\ 1 \\ \vdots \\ -1 \\ \vdots \\ 0 \end{bmatrix}$$

$$B_{out} = B + b_{ij}e_{ij}e_{ij}^T \quad (\text{A.5})$$

Here B_{out} is the B matrix after line k is out. e_{ij} has 1 at the starting bus position of line k and -1 at the ending bus position. b_{ij} is the susceptance of the line k with starting and ending bus positions at i and j respectively.

From the matrix inversion lemma

$$(B + cd^T)^{-1} = B^{-1} - B^{-1}c(I^M + d^T B^{-1}c)^{-1}d^T B^{-1} \quad (\text{A.6})$$

where B is an $n \times n$ matrix, c and d are $n \times m$ matrices and I is an $m \times m$ Identity matrix.

Applying the Matrix inversion lemma to our problem results in the calculation of B_{out}^{-1} from base case B^{-1} matrix:

$$B_{out}^{-1} = B^{-1} - \frac{B^{-1}b_{ij}e_{ij}e_{ij}^T B^{-1}}{1 + b_{ij}e_{ij}^T B^{-1}e_{ij}} \quad (\text{A.7})$$

Here B^{-1} is the base case pseudoinverse of the B matrix with elements only in the positions which are in the range of area buses.

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Part II

A Structural Approach to Operations and Planning in the Changing Industry

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1. Introduction

Section 2 of Part 2 in this report is contributed by Prof. Marija Ilic, as part of her broader research efforts, and describes a general structural approach to modeling and control of the changing electric power systems. The problem of aggregated information exchange and its implementation using PMUs and other sensors is considered in the context of next generation SCADA, referred to as Dynamic Monitoring and Decision Systems (DyMoNDS). This contribution is summarized for its relevance to ensuring reliable electricity service by the changing electric power system that is characterized by dynamic actions not fully under the control of utility operators. Specific methods reported in sections 3 and 4 are put in the context of broader framework for supporting interactions in complex electric power grids so that each group of grid users, and the grid itself, contribute to electricity service according to well-defined interactions within a multi-layered modeling for future electric power grids. A transformed state space lends itself naturally to answering some key questions in this project, namely determining the minimum number of sensors (PMUs) and PMU-enabled actuators so that power transfers across area boundaries are stabilized in closed loop is achieved. The transformed state space is fully formalized in a major recently completed publication [R3]. It has been conceptualized how, instead of modeling system dynamics as a single “flat” model, interactions between components within an area and interactions between areas within a region can be captured by utilizing the notion of so-called interaction variables. This concept could form the basis of next generation SCADA needed for PMU-based control without excessive complexity.

Specific contributions in Section 3 are made in collaboration with graduate student Nipun Popli, who is currently a postdoctoral fellow at the MIT Energy initiative. Early on in this project the CMU team worked on graph methods for placing the PMUs and controllers so that the small signal stability of an electric power system is achieved. Theoretical work was done on structural controllability and observability conditions which can be used to select minimum number of locations and types of sensors and actuators to ensure stable operation. This resulted in the following publications:

- Nipun Popli, Sergio Pequito, Soumya Kar, A Pedro Aguiar, and Marija Ilic. Selective strong structural minimum cost resilient co-design for regular descriptor linear systems. to appear in Automatica (arXiv preprint arXiv:1704.01157, 2017)
- S. Pequito, N. Popli, S. Kar, M. Ilic, and A.P Aguiar. A framework for actuator placement in large scale power systems: Minimal strong structural controllability. In Proceedings of IEEE International Workshop on Computational Advances in Multi-Sensor Adaptive Processing, December 2013.

- Nipun Popli. Multi-layered Energy Conversion and Frequency Control in Complex Electric Power Systems. PhD thesis, Department of Electrical and Computer Engineering, Carnegie Mellon University, USA, 2017.

Dr. Nipun Popli continued working at CMU after his doctoral thesis defense. Dr. Slava Maslennikov (ISO-NE) served as an industry advisor on his PhD thesis committee. This has ensured direct collaboration with our industry member who provided us with most feedback throughout this project.

Specific contribution to this project was made by the CMU graduate student Stefanos Baros, currently also a postdoctoral fellow at the MIT Energy Initiative. Under this effort specific control schemes of wind farms were introduced by incorporating feedback signals from PMU measurements, to enable them to regulate their power output to system-conditions-dependent dynamic references. By meeting these power references the WFs can contribute to guaranteed small-signal stability of the interconnected system while its loading conditions vary. As a follow up to our earlier work, we have further enhanced the methods for distributed control of wind power plants, and two technical papers have been published:

- S. Baros, M. Ilic, Distributed Torque Control of Deloaded Wind DFIGs for Wind Farm Power Output Regulation, IEEE Transactions on Power Systems, Volume: 32, Issue: 6, pp. 4590 - 4599, Nov. 2017.
- S. Baros, M. Ilic, A Consensus Approach to Real-time Distributed Control of Energy Storage Systems in Wind Farms, IEEE Transactions on Smart Grid, vol. PP, Issue: 99, pp.1-1, Sept. 2017 This work represents an illustration of how one may use PMUs to enable integration of renewable resources.

Part 2 of this report is organized as follows. In Section 2, the efforts and specific contributions are put in the context of broader needs and opportunities emerging in the changing industry. As the industry is changing, many solutions are being proposed. It has been difficult to put the specific methods into use. To cope with this problem, a unified approach is needed for modeling which supports extensions of current operating protocols to include and use fast measurements without data overload, and at value. In particular, placement of PMUs for enabling best power delivery requires in start that these make the system dynamics observable. Section 3 provides results on specific methods introduced to do this. Similarly, once the system dynamics is observable, one can begin to place actuators and protection to close the loop and ensure stable operation. Analogue method can be used to place actuators for fast closed-loop control. Ultimately, next generation SCADA begins to emerge into carefully selected fast communications scheme supporting fast control/protection that ensures no instabilities, such as voltage collapse. Finally, Section 4 concerns specific uses of PMUs for controlling wind farms so that they can in an aggregated way provide power committed to the system operator. The specific contributions and publications are examples of how this can be done, assuming PMU measurements are available and utilized.

2. A structural approach to operations in the changing industry

2.1 Overview

The overall approach we take is based on the structural modeling and performance metrics needed for monitoring and control of the changing electric power systems. An important objective has been to establish a foundation for multi-layered modeling so that:

- A systematic information structure is established between different industry layers, starting from EHV balancing authorities (BAs), through transmission providers, load serving entities (LSEs), distribution companies, down to very small clusters of end users.
- This information structure forms the basis for future general end-to-end multi-layered SCADA with well-defined functionalities.
- The next generation SCADA builds on the existing information exchange supporting economic dispatch and automatic generation control (AGC).
- An interaction variable (intVar) is an aggregate measure of multi-rate multi-spatial power imbalance between an intelligent Balancing Authority (iBA) and the rest of the system to which it is interconnected.
- Different sensors and communication channels are needed for different level of temporal and spatial granularity. For the first time even the very fast intVar relevant for monitoring fast transient instabilities and, even electromagnetic interactions between different parts of power electronically controlled parts of the system can be used. PMUs are one particular example of such fast sensors.

We provide the contextual rationale for extending today's SCADA and NERC criteria to multi-temporal and multi-spatial information exchange protocols in support of highly distributed and highly dynamic industry in which resources, demand and grid which potentially can cause reliability problems and can also contribute to enabling more reliable electricity services.

This section is based on the invited presentation made by Prof Marija Ilic to PSERC Systems Stem, December 2016 in Atlanta, Georgia. The work is motivated by the general observation that as the industry moves forward to adopt new technologies, and to integrate new non-utility stakeholders into the electric power grid, many non-unique/methods-dependent solutions become possible. In particular, key to the PSERC project S-64, it is clear that there exists the need for next generation controllers using PMUs to avoid system stress, such as congestion of thermal limits, voltage collapse, loss of synchronism, inter-area oscillations and many other complex grid problems. Potentially powerful methods are generally hard to utilize for variety of reasons. To start with, it is hard to explain to map potential benefits from these methods into binding information protocols and reliability requirements. As a result, there exists a disconnect between what PMUs and new smarter controllers/protection can do, on one hand, and the regulatory and financial incentives for their deployments. In this section we propose a possible way forward by which all entities

connected to the grid are required to become or belong to an intelligent Balancing Authority iBA [Stefanos Baros, and Marija Ili. “Intelligent balancing authorities (IBAS) for transient stabilization of large power systems.” PES General Meeting— Conference & Exposition, 2014 IEEE. IEEE, 2014.] responsible for either operating in an islanded disconnected way or, if connected, exchanging minimum information at the pre-agreed rates. This minimum information exchange basically needs to be such that iBAs meet their own internal sub-objectives subject to ensuring that commitment made through the required information exchange are met. This approach is intended to both eliminate “free riders” and to manage otherwise overwhelming complexity which can result from the need for a single system operator to model and control very detailed spatial and temporal interconnected system dynamics. At the same time, it is a natural outgrowth of today’s balancing authorities. Notably, the emergence of “mini-control areas” closer to the end users was foreseen some time ago by both early visionaries in our field [Lester Fink in Ilic, Marija, Francisco Galiana, and Lester Fink, eds. Power systems restructuring: engineering and economics. Springer Science & Business Media, 2013]. Also, we observe that early in industry deregulation some major non-utility players, including Enron [Free, Clinton, and Norman Macintosh. “Management control practice and culture at Enron: The untold story.” (2006)], wanted to become their own control areas, but this idea was not approved by the industry. More recently, it has become practically impossible to manage highly unconventional intermittent resources as well as price responsive demand according to reliability rules in place.

Notably, managing uncertainties is difficult since most of the rules rely on (N-1)/(N-2) deterministic criteria. The technologies and methods capable of managing these uncertainties are therefore hard to justify and pay for. Speaking more generally, anything that is not viewed as a deterministic disturbance is managed by setting margins just in case these uncertainties occur. There are no specific end users which are identified as sources of disturbances nor specific control/protection technologies dedicated to managing these disturbances. Section 2 is written with an intent to suggest a possible extension of today’s balancing authorities (BAs) into iBAs with carefully defined binding information exchange. The main R&D challenge then becomes the one of physics-based modeling for setting specifications to be met by all groups of system users. These must be basis for straightforward to understand/enforce industry protocols. Prof. Marija Ilic proposed such approach for industry consideration in context of an invited testimony to FERC; FERC recommended to further discuss this proposal with industry. In this report we re-iterate principles of this proposal and attach as an appendix to the report the FERC testimony. In light of project S-64 methods monitoring and control methods introduced here are some examples of technologies needed to be used by the future iBAs so they implement methods for meeting iBA specifications proposed. Effectively, the proposed iBAs as the basis for next generation SCADA are an outgrowth of today’s BAs which are more granular spatially and temporally. Because of fast intermittent disturbances it is no longer possible to only set criteria for quasi-static area-control-error (ACE), but iBAs must be responsible for small signal stability and transient stability. Similarly, spatial aggregation and granularity are an end-to-end concept which includes distribution systems, microgrids, non-utility owned distributed energy resources (DERs), demand response participation and alike. Finally, and possibly most critical, are extensions for enabling risk management related to wide range of disturbances and topology changes. If congestion occurs on the high voltage grid, it can be managed by the large generators as well as by the smaller clusters of grid users [Ilic, M., Joo,

J. Y., Carvalho, P. M., Ferreira, L. A., & Almeida, B. (2013, August). Dynamic monitoring and decision systems (DYMONDS) framework for reliable and efficient congestion management in smart distribution grids. In Bulk Power System Dynamics and Control-IX Optimization, Security and Control of the Emerging Power Grid (IREP), 2013 IREP Symposium (pp. 1-9). IEEE].

2.2 Main industry challenge

The above concerns comprise several major technical challenges:

1. Establishment of quantifiable performance criteria/metrics/protocols needed to support automated control of hard-to-predict (uncertain) deviations from scheduled conditions (power profiles and/or equipment status).
2. These are needed to avoid:
 - operational problems (short-term instabilities)
 - long-term instabilities (resource adequacy, financial instabilities, not discussed in this project).

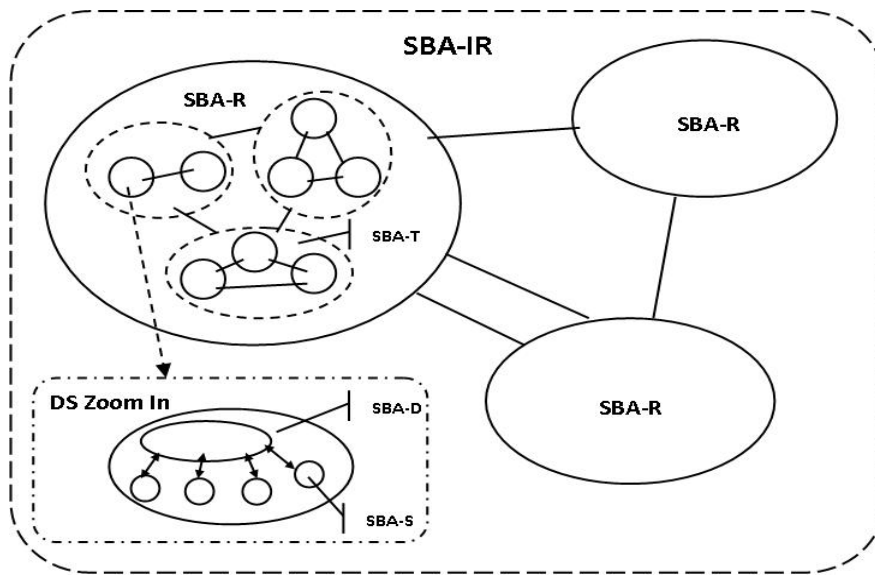
The basic principles of the existing standards, notably AGC principles are summarized in an earlier PSERC report [Ilic, Marija. “Toward Plug-and-Play Standards for Dynamics in the Changing Electric Energy Systems.” (2015)]. In the same report principles of new standards for the changing industry by evolving from the existing standards (based on similar high-level principles) are proposed.

The innovation challenges to deployment of methods proposed in project S-64 are as follows:

- There is no single entity charging the entire design, possibly different for micro-grids
- The power network spreads over vast geographical areas, creating challenges for sensing, communication and estimation.

Key issues that must be overcome are:

- Establishing a new information structure supported by future SCADA. The proposed structural approach is one possible way forward [Ilic, Marija D. “Toward a unified multi-layered modeling and simulation paradigm for electric energy systems.” Power Symposium (NAPS), 2017 North American. IEEE, 2017.]
- What needs to be controlled
- Where to place sensors and why
- What needs to be communicated



- SBA: Smart Balancing Authorities
(Generalization of Control Area)
- IR: Inter-Region
- R: Region
- T: Tertiary
- D: Distribution
- S: Smart Component

Figure 2.1: General structure of the emerging electric energy systems

2.3 General structure of the changing electric energy systems

Shown in Figure 1 is a sketch of the emerging electric energy system in which smart (intelligent) Balancing Authorities are interacting [Ilic, M., “Dynamic Monitoring and Decision Systems for Enabling Sustainable Energy Services”, Network Engineering for Meeting the Energy and Environmental Dream, Scanning the Issue, Proc. of the IEEE, 2011.] Major observations:

- All about balancing power at the right temporal and spatial granularity (makes it simple)
- But, the models used are not explicitly posed this way
- New structural modeling to overcome this problem [Ilic, Marija D. “Toward a unified modeling and control for sustainable and resilient electric energy systems.” Foundations and Trends in Electric Energy Systems 1.1-2 (2016): 1-141.]
- Use to support interactive Dynamic Monitoring and Decision Systems- DyMonDS
- Much room for generalizing today’s hierarchical control
- Much room for making use of nonlinear control; use of PMUs to manage fast transient and small signal oscillations in real time.

2.4 Fundamental modeling contribution

Arriving at a physics-based structural modeling required using transformed state space for representing interactions between sub-systems/iBAs. Much the same way as today’s specifications for automated generation control (AGC) are in terms of energy/power measured as area control error (ACE), we propose to model the high level interactions between iBAs using power and rate of change of power for a stratum of temporal horizons relevant for ensuring stable and reliable operation. In [Ilic, Marija D., and Rupamathi Jaddivada. “Multi-layered interactive energy space modeling for near-optimal electrification of terrestrial, shipboard and aircraft systems.” Annual Reviews in Control (2018).] the fundamental underpinnings of this transformed state space modeling are derived. For purposes of this project and possible industry consideration it is relevant to summarize that interaction variables are a triple of data, representing power, rate of change of power and energy (time) specified for each temporal horizon of interest. This means that for very fast transient processes one must have technologies which are extremely flexible and are capable of delivering power at the rate specified over an extremely short time interval relevant for transient stability. This is followed by the slower specifications using the same common interaction variables. For example scheduling in energy markets will require specifications by the iBAs about power, rate of power produced (consumed) (“ramp rate”) and time interval (hour, 15 minutes). The same way, frequency regulation will require the same variable specifications over the time interval relevant for this power balancing. If this is done, the system frequency, as a consequence, will remain within the tolerance specified by the industry [Ilic, M., Skantze, P., Yu, C. N., Fink, L., & Cardell, J. (1999, February). Power exchange for frequency control (PXFC). In Power Engineering Society 1999 Winter Meeting, IEEE (Vol. 2, pp. 809-819). IEEE.]

2.5 The role of PMUs and methods described in Sections 3 and 4

Assume now that a set of protocols/standards based on these interaction variable specifications is in place and the next generation SCADA communicates these variables for coordinated management at the system level. Meeting these requirements at the very fast rates (for transient and/or small signal stability) will prompt the iBAs to deploy and use methods which are capable of ensuring that the specifications communicated in terms of fast interaction variables are implementable. Methods introduced in Section 3 can be used to decide placement of PMUs, controllers and their communications (iBA-level SCADA) to ensure that the specifications about the net interaction of each iBA with the rest of the system are met. This is then utilized by the clusters of wind farms (Section 4) for their contribution to IBA meeting the specified performance. The entities utilizing more effective technologies will be capable of meeting these specifications at lower cost and serve their end users better. At the same time, they can participate in system-level management and electricity markets more competitively.

3. PMU-enabled small-signal voltage and frequency stabilization via decentralized control laws

We summarize CMU's proposed approach to co-design PMU-communication-Storage to guarantee voltage or frequency stabilization with decentralized control laws. The overall objective of the proposed co-design architecture is to guarantee observability, controllability and stable eigenmodes, in closed-loop, for both voltages and frequencies across the network.

3.1 Voltage and frequency stabilization: A strong structural approach

A large-scale power system's dynamics, for a wide range of operating conditions, is represented by a set of nonlinear differential algebraic equations as:

$$\dot{x}(t) = f(x(t), y(t), u(t), p(t)), \quad (3.1)$$

$$0 = g(x(t), y(t), u(t), p(t)). \quad (3.2)$$

where $x \in \mathbb{R}^n$, $u \in \mathbb{R}^m$, $y \in \mathbb{R}^p$ are the states, inputs and outputs, and $p \in \mathbb{R}^q$ the system parameters. Typically, for a small-signal stability analysis, the set (3.1)-(3.2) is linearized around the nominal operating point of the grid, to obtain a linear system:

$$\Delta \dot{x} = A \Delta x + B \Delta u, \quad (3.3)$$

$$\Delta y = C \Delta x. \quad (3.4)$$

The sets of equations (3.3)-(3.4) represent a standard state-space form. Subsequently, critical system properties such as observability, controllability, and stability of open-loop eigenmodes are assessed. Nevertheless, these assessments are based on following strong assumptions:

1. System Identification: The machine parameters $p \in \mathbb{R}^q$ are known accurately.
2. Time-invariance: The linearized representation is assumed to be fixed over time.

Now, it must be noted that observability, controllability, and stability properties are numerics-dependent. In other words, these properties are highly susceptible to (in)accuracies of the parameters and the time-invariance assumption for the linear representation. Besides, for large systems, the properties are also influenced by the accuracy of the computational algorithms. In this project we invoke the theory of selective strong structural systems to address such challenges. We assume that only the structure of the system matrix A is given. Specifically, the sparsity of the matrix A is categorized in the form of *strictly zero entry* (0), *strictly non-zero entry* ($\times$), or *arbitrary real-value entry* ($\otimes$) which can take zero or non-zero value. Furthermore, we assume that sparsities of the control input matrix B and output matrix C are unknown. In other words, the input and the output matrices are to be designed. For the given sparsity, the matrix A can take multiple numerical forms. Therefore, given the system matrix structure, the goal is to determine:

1. Best locations for placing PMUs, which measure only one state variable each, to ensure system observability for all nominal operating conditions.

2. Best locations for placing ideal controllers, for instance, capacitor banks for voltage stabilization or fast storage for frequency stabilization, which control only one state variable each, to ensure system controllability for all nominal operating conditions.
3. Best communication channels between the PMUs selected in 1), and the controllers selected in 2), such that eigenmodes, in closed-loop, are stabilizable for all nominal operating conditions. Specifically, there are no fixed modes in closed-loop.

The aforementioned objectives translate in to the following subproblems:

1. Design sparsity of the output matrix C , with each row having exactly one *strictly non-zero entry* ($\times$), so that (A, C) are observable for all numerical realizations.
2. Design sparsity of the input matrix B , with each column having exactly one *strictly non-zero entry* ($\times$), so that (A, B) are controllable for all numerical realizations.
3. Design sparsity of the gain matrix K , coupling each *strictly non-zero entry* ($\times$) in output matrix C to exactly one *strictly non-zero entry* ($\times$) in input matrix B , so that the eigenmodes of the closed-loop matrix $(A - BKC)$ are stabilizable for all numerical realizations.

Motivated by the need for a formal framework to deploy storage-based technologies to ensure system-wide dynamic controllability, the concept of strong structural theory was utilized in [1]. More precisely, the storage-based technologies such as batteries, electric vehicle charging stations, cluster of flywheels, fast demand response, etc actuate the most critical state variables in the form of power injections and bus frequencies, to guarantee system-wide dynamic controllability across wide range of operating conditions. For instance, in [1], it was illustrated that careful selection of candidate load for frequency-based demand response precludes the requirement of expensive grid-scale storage. For example, in support of frequency stabilization, the matrix A of the linearized system in (3.3) is inherently singular due to power conservation laws captured by the algebraic equations in (3.2). Therefore, the controllability for the pair (A, B) cannot be ensured. So, the issue of an interconnected system's singularity, or loss of controllability, due to power conservation laws, can be addressed by placing either a fast storage device or automating controllable demand technologies [1, 2]. Effectively, by placing of fast or ideal balancing resources, the matrix B is designed so that the pair (A, B) is controllable. In addition, by invoking the concept of duality, our proposed notion of system-wide dynamic controllability can be extended to ensure system-wide dynamic observability [1]. Particularly, the framework allows for the selection of state variables to be measured with fast PMU-based sensors. For instance, in case of voltage stabilization, it is difficult to guarantee observability for pair (A, C) under certain numerical scenarios resulting from some of the operating conditions. To overcome this problem, the matrix C can be designed for a provably observable pair (A, C) over a wide range of operating condition. Now, in the context of large-scale power systems, we often require decentralized control schemes due to limited data sharing between the sensors and the controllable resources. The information pattern captures the information accessibility to controllable resources and implicitly represents the communication/cyber requirements associated with the decentralized control scheme, and its design is crucial to attain feasible decentralized control solutions. Subsequently, it is imperative to design communication channels to close the loop between the sensors and the actuators without fixed modes [3].

We propose that the guarantee of closed-loop stability, achieved by co-design approach to PMU-communication-storage architecture, is robust to parametric uncertainties as well as the assumption of time-invariance of the linearized system [4]. The proposed approach can be adopted to address small-signal stability of voltage/frequency around different operating points. In summary, conventional analysis only tests if instability may occur with the existing primary controllers, however, we propose a co-design of co-design approach to PMU-communication-storage architecture for obtaining decentralized control laws that would ensure the stability properties. Next, a proof-of-concept example is provided in support of the proposed approach.

3.2 Proof-of-concept: 5-bus power system

Consider in Fig. 3.1 a 5-bus power system with five dynamical components interconnected through transmission lines. These are two coal-fired steam turbines C_1 , C_2 , one gas-fired combustion turbine G_3 and the aggregate loads D_4 , D_5 . The generators C_1 , C_2 and G_3 are modeled as linearized

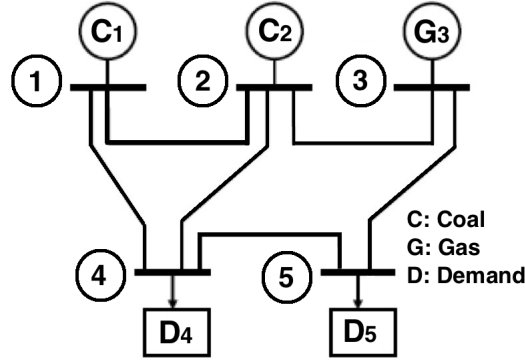


Figure 3.1: IEEE 5-bus test system ($1, 2, 3, 4, 5$ are the bus numbers)

governor control. The aggregate loads D_4 , D_5 , modeled as dynamic components, are represented by swing equations. Subsequently, the generators and the loads are electrically coupled through the differentiated linearized real-power flow equations¹. The 5-bus power system is represented as a 16^{th} order LTI system (3.3), and the structural representation of the matrix $A_{5_{bus}}$ is of the form:

where, the state variables are described in Table 3.1.

The first step is to ensure controllability of the 5-bus system over wide range of operating conditions, particularly for a given or a known sparsity of the structural matrix $A_{5_{bus}}$. Therefore, we determine the minimal number of storage-based devices to be placed in the system, along with their locations. Now, let there be a 16^{th} order structural identity matrix I_{16} , with diagonal entries as strictly nonzero ($\times$) and off-diagonal entries as strictly zero (0). Therefore, for each $\lambda \in \mathbb{C}$, the sparsity of the matrix $A_{5_{bus}}^\lambda = A_{5_{bus}} - \lambda I_{16}$ is of the form: Next, the rows and columns of the structural matrix $A_{5_{bus}}^\lambda = A_{5_{bus}} - \lambda I_{16}$ are permuted to obtain a lower-triangular form $M_{5_{bus}}^\lambda$ (see [1] for details on algorithm):

where the row and the column indices labelled in $M_{5_{bus}}^\lambda$ correspond to the row and the column indices in $A_{5_{bus}}^\lambda$, i.e., before permutations, respectively. Simply speaking, they correspond to

¹The coupling constraints are the linearized power flow equations. For the purpose of real-power balancing, decoupling between real and reactive power flow is assumed.

$A_{5\text{bus}}$

A_5^λ

M_5^λ

Table 3.1: 5-bus power system state variables

States	Description
x_1	C_1 's prime mover frequency
x_2	C_1 's turbine mechanical power output
x_3	C_1 's governor valve position
x_4	C_2 's prime mover frequency
x_5	C_2 's turbine mechanical power output
x_6	C_2 's governor valve position
x_7	G_3 's turbine fuel flow
x_8	G_3 's prime mover frequency
x_9	G_3 's governor valve position
x_{10}	frequency at bus-4
x_{11}	frequency at bus-5
x_{12}	power injection by C_1
x_{13}	power injection by C_2
x_{14}	power injection by G_3
x_{15}	power consumption by D_4
x_{16}	power consumption by D_5

$$M_{5\text{bus}}^\lambda = \begin{bmatrix} & 3 & 2 & 1 & 12 & 6 & 5 & 4 & 13 & 9 & 8 & 7 & 10 & 14 & 15 & 11 & 16 \\ 2 & \times & \otimes & & & & & & & & & & & & & & \\ 3 & \otimes & 0 & \times & & & & & & & & & & & & & \\ 1 & \times & \times & \otimes & \times & & & & & & & & & & & & \\ 5 & 0 & 0 & 0 & 0 & \times & \otimes & & & & & & & & & & \\ 6 & 0 & 0 & 0 & 0 & \otimes & 0 & \times & & & & & & & & & \\ 4 & 0 & 0 & 0 & 0 & \times & \times & \otimes & \times & & & & & & & & \\ 8 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \times & \otimes & & & & & & \\ 9 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \otimes & 0 & \times & & & & & \\ 12 & 0 & 0 & \times & \otimes & 0 & 0 & \times & 0 & 0 & 0 & 0 & \times & & & & \\ 13 & 0 & 0 & \times & 0 & 0 & 0 & \times & \otimes & 0 & 0 & \times & \times & & & & \\ 7 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \times & \otimes & 0 & \times & & & \\ 10 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \otimes & 0 & \times & & \\ 14 & 0 & 0 & 0 & 0 & 0 & 0 & \times & 0 & 0 & 0 & \times & 0 & \otimes & 0 & \times & \\ 15 & 0 & 0 & \times & 0 & 0 & 0 & \times & 0 & 0 & 0 & 0 & \times & 0 & \otimes & \times & \\ 11 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \otimes & \times \\ 16 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \times & \times & 0 & 0 & \times & \otimes \end{bmatrix}$$

the state variables indices to be considered for the storage-PMU-communication channel design. Notice that $M_{5\text{bus}}^\lambda$ contains 13 strictly non-zero entries, marked as $\times$:

It must be noted that there exist no non-zero entries in rows labeled as 13, 15, 16. In addition, the rows with labels 12, 13 in $M_{5\text{bus}}^\lambda$ can be permuted so that there are no non-zero entries in rows labeled as 12, 15, 16. Similar argument holds for the rows with labels 14, 15. Therefore, it requires three dedicated storage-devices, and the possible collection of state variables that can be controlled by dedicated actuators are indexed by $\mathcal{I}_1 = \{12, 14, 16\}$, $\mathcal{I}_2 = \{13, 14, 16\}$, $\mathcal{I}_3 = \{12, 15, 16\}$, or $\mathcal{I}_4 = \{13, 15, 16\}$ (notice the row indices highlighted in red). Corresponding to these solutions, there are three possible ways to construct the input matrix $B_{5\text{bus}}$, so that the row-column permutation of the concatenated matrix $[A_{5\text{bus}}^\lambda, B_{5\text{bus}}]$ will fulfill Popov controllability test for all possible realization of the structural matrix $A_{5\text{bus}}^\lambda$. To summarize, at least three dedicated storage devices

$$M_{5\text{bus}}^\lambda = \begin{bmatrix} & 3 & 2 & 1 & 12 & 6 & 5 & 4 & 13 & 9 & 8 & 7 & 10 & 14 & 15 & 11 & 16 \\ 2 & \times & \otimes & & & & & & & & & & & & & & \\ 3 & \otimes & 0 & \times & & & & & & & & & & & & & \\ 1 & \times & \times & \otimes & \times & & & & & & & & & & & & \\ 5 & 0 & 0 & 0 & 0 & \times & \otimes & & & & & & & & & & \\ 6 & 0 & 0 & 0 & 0 & \otimes & 0 & \times & & & & & & & & & \\ 4 & 0 & 0 & 0 & 0 & \times & \times & \otimes & \times & & & & & & & & \\ 8 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \times & \otimes & & & & & & \\ 9 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \otimes & 0 & \times & & & & & \\ 12 & 0 & 0 & \times & \otimes & 0 & 0 & \times & 0 & 0 & 0 & 0 & \times & & & & \\ 13 & 0 & 0 & \times & 0 & 0 & 0 & \times & \otimes & 0 & 0 & \times & \times & & & & \\ 7 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \times & \otimes & 0 & \times & & & & \\ 10 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \otimes & 0 & \times & \\ 14 & 0 & 0 & 0 & 0 & 0 & 0 & \times & 0 & 0 & 0 & \times & 0 & \otimes & 0 & \times & \\ 15 & 0 & 0 & \times & 0 & 0 & 0 & \times & 0 & 0 & 0 & 0 & \times & 0 & \otimes & \times & \\ 11 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \otimes & \times \\ 16 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \times & \times & 0 & 0 & \times & \otimes & \end{bmatrix}$$

are required to achieve the condition of controllability over wide range of operating condition, and their placement in the 5-bus system is non unique. Nevertheless, as per the four alternative input matrices achieving the minimal design, the state variables to be controlled are subsets of the nodal power injections/consumptions. The states x_{16} always require a dedicated storage, i.e., the power consumption by the aggregate load D_5 . For example, instead of placing a storage device at D_5 to actuate x_{16} , a possible alternative is to actuate the aggregate load by embedding local automation. The second storage device can be placed at bus-4 (x_{15}), or, at bus-3 (x_{14}). The third can be placed at bus-4 (x_{15}), or, at bus-3 (x_{14}). All possible input matrices are physically feasible. However, based on performance objective, for example cost or location of storage, some of the input matrices may be more suitable. But, all possible input matrix constructions are physically feasible. Similarly, for observability across wide range of operating of operating conditions, three dedicated PMU-based sensors are required. However, in contrast to the non unique solutions to guarantee controllability, the solution to ensure observability condition is unique, and consists in measuring with three dedicated sensors, the state variables indexed by $\mathcal{J} = \{2, 5, 8\}$. The output matrix $C_{5\text{bus}}$ can be constructed in a unique way. The state variables that need to be measured are turbine mechanical power outputs of C_1 (bus-1) and C_2 (bus-2), and the prime mover frequency deviations of G_3 (bus-3), marked as $\otimes$: Next, minimum three communication links are required to relay the data from the PMU-based sensors measuring the state variables indexed by $\mathcal{J} = \{2, 5, 8\}$, to the three storage-based devices. The objective is to ensure, in closed-loop, the system is stabilizable for all realizations of the matrices. In other words, for the given sparsity of the system matrix $A_{5\text{bus}}$, each sensor-measurement (represented by one row in $C_{5\text{bus}}$), is fed to each storage-based controller (represented by one column in $B_{5\text{bus}}$), so that the output-based feedback ensures stability of the system for all possible realization of $A_{5\text{bus}}$, $B_{5\text{bus}}$, and $C_{5\text{bus}}$. In other words, the exist no fixed modes for any of the operating condition. More precisely, the stabilizability of the system is guaranteed is the sensors and the storage are paired based on the approach proposed in [4]. In case of the given 5-bus system, non unique pairing exists between the three PMUs and three storage devices. Therefore, suppose that the cost associated with the possible storage placement schemes is uniform, i.e., the placing of storage-based energy resources at $\mathcal{S}_1 = \{12, 14, 16\}$, $\mathcal{S}_2 = \{13, 14, 16\}$, $\mathcal{S}_3 = \{12, 15, 16\}$, or $\mathcal{S}_4 = \{13, 15, 16\}$ require same capital investment. In addition, assume that the cost associated with communication channels are nonuniform, and are based on the distance between the buses. Assuming a homogenous cost of control by battery storage, and a homogenous

cost of sensing by PMUs, the cost of communication links is determined by the pairings between the PMUs and the storages devices. If the PMU-based measurements of the state variables indexed by $\mathcal{J} = \{2, 5, 8\}$ are fed to the dedicated storage devices actuating the state variables indexed by $\mathcal{J}_2 = \{13, 14, 16\}$, based on the pairings $(13, 5)$, $(14, 8)$ and $(16, 2)$, minimum communication cost is incurred. Notice that the pairing between PMUs and storage devices. The pairings $(13, 5)$ and $(14, 8)$ are placed at the same geographical location, i.e., bus-2 and bus-3, respectively. In addition, the proposed stabilizability property can be made robust with respect failure of dedicated storage device(s), dedicated PMU-based sensor(s), or a communication channel(s) (see [4] for details).

4. Distributed control of wind farms for power output regulation

In our work we developed distributed control methods for power output regulation of wind farms comprised of state-of-the-art (SoA) wind generators (WGs). Since wind farms produce high amount of power in current power systems, we can leverage their power regulation capability together with the advanced measurement capabilities of PMUs to ensure small signal stability and effective power control in certain areas of power systems. In the first thrust which we analyze below, we developed a distributed control design which can be adopted by SoA WGs with integrated storage devices to continuously, dynamically and distributively self-organize and control their power outputs by exploiting limited peer-to-peer communication. With the proposed scheme a wind farm can ensure that its total power output tracks a total power reference under highly dynamical conditions. This reference can be fast-varying depending on the overall system conditions. In the second thrust which we analyze below, we developed a distributed method for torque control of deloaded wind double-fed induction generators (DFIGs), the most common type of WGs deployed today. With this control scheme deloaded DFIGs can dynamically, distributively and fairly self-dispatch and adjust the power they generate so that their total power closely tracks a dynamic reference. By designing these advanced control methods, our goal was to enable WFs to effectively regulate their power outputs fast and dynamically in order to meet system-level stability requirements as well as to ensure that power transferred through specific transmission lines in the vicinity of the WFs respects certain thermal limits. Implementation of our proposed advanced feedback control schemes that we analyze below requires that several state-variables are measured using PMUs.

4.1 A consensus approach to real-time distributed control of energy storage systems in wind farms

According to a U.S. DOE study envisions that the wind integration level in the coming years (by 2050) is going to be such that 35% of the U.S. annual electricity demand will be generated by wind generators. Although high wind integration levels are desirable, there are some obstacles that need to be circumvented before they become realizable. The most important challenges related to high wind integration are balancing wind intermittency by enabling WGs to provide short-term predictable power and to provide frequency/inertial control. Because of wind intermittency, power quality deteriorates and the cost of electricity increases since expensive generators are called to generate the mismatch between scheduled/predicted and real wind power. At the same time, having WGs replacing SGs without providing frequency/inertial control decreases the overall inertia of the grid. As a result, power imbalances cause a more pronounced effect on the system frequency. Fortunately, nowadays, General Electric (GE) is commercializing state-of-the-art (SoA) WGs that have energy storage incorporated into their design, which provides a promising technology for overcoming the above issues. Nevertheless, in both industry and academia, no systematic control methods for this WG technology have been proposed that reveal and take full advantage of its capabilities. In our research, we established several novel distributed control architectures for the SoA WGs that have, among others, the following attributes: 1) they are based on ideas from multi-agent systems theory (e.g consensus), enabling eets of SoA WGs to accomplish mul-

multiple complex capabilities that require coordination; 2) they integrate and leverage the available advanced sensing, communication technologies into the control scheme of the SoA WGs; 3) have theoretical guarantees for the stability and performance they attain.

In our paper “A Consensus Approach to Real-time Distributed Control of Energy Storage Systems in Wind Farms”, we established a novel distributed control architecture for SoA WGs that enables them to balance the wind intermittency and provide short-term predictable power at the wind farm level, using the storage devices in a load-sharing fashion (i.e all storage devices provide the same amount of power). Lastly, we developed Control Lyapunov Function-based power electronics controllers for SoA WGs that implement the proposed protocol. The distributed power-electronics control architecture: 1) will contribute to the total generation cost reduction (especially in large-scale applications) since it uses stored wind energy, which eliminates the need for fast ramping-up SGs; 2) is practically realizable, requiring WGs to exchange feedback signals that can be easily measured locally; 3) has stability and performance that are guaranteed with or without communication delays.

On the practical side, regarding SoA WGs, our work is the first work that introduces a distributed power-electronics control architecture that exploits and reveals their full potential and enables them to accomplish complex objectives through self-organization and coordination. Further, we emphasize that since these WGs will be main energy generating units in the coming years, systematic control methods that are both practical and mathematically rigorous are needed before their large-scale application. Below we present the main ideas and results obtained in this research thrust.

4.2 Modeling

Here we are concerned with wind DFIGs as they are the most popular and commonly deployed WGs today. Wind DFIGs are characterized by high operational efficiency as they can vary the speed of their rotors in a wide range extracting maximum power from the wind for a large span of wind speed conditions. Interestingly, General Electric (GE) is now commercializing DFIGs with storage devices with the additional flexibility (over standard DFIGs) of being capable of meeting power commitments even when the wind conditions are poor. A typical DFIG with a storage device is depicted in Fig. 4.1. In what follows, we use the following notation convention. We denote the set of SoA DFIGs by $\mathcal{G}$ and index each WG by i such that $i \in \mathcal{G}$. The relevant models for our analysis are the models of the GSC, the interfacing capacitor, and the supercapacitor which we present next.

Grid-side Converter Model

The GSC model captures the dynamics of its output current in a $d - q$ coordinate system and it can be stated as follows.

$$\frac{dI_{dg,i}}{dt} = -\omega_s \left(\frac{R_{g,i}}{L_{g,i}} \right) I_{dg,i} + \omega_s I_{qg,i} + \omega_s \left(\frac{V_{dg,i} - V_{s,i}}{L_{g,i}} \right) \quad (4.1a)$$

$$\frac{dI_{qg,i}}{dt} = -\omega_s \left(\frac{R_{g,i}}{L_{g,i}} \right) I_{qg,i} - \omega_s I_{dg,i} + \omega_s \left(\frac{V_{qg,i}}{L_{g,i}} \right), i \in \mathcal{G} \quad (4.1b)$$

The constants $R_{g,i}, L_{g,i} \in \mathbb{R}_+$ denote the resistance and inductance of the GSC, $V_{s,i} \in \mathbb{R}$ the terminal voltage and $V_{dg,i}, V_{qg,i} \in \mathbb{R}$ the GSC’s controllable voltage components.

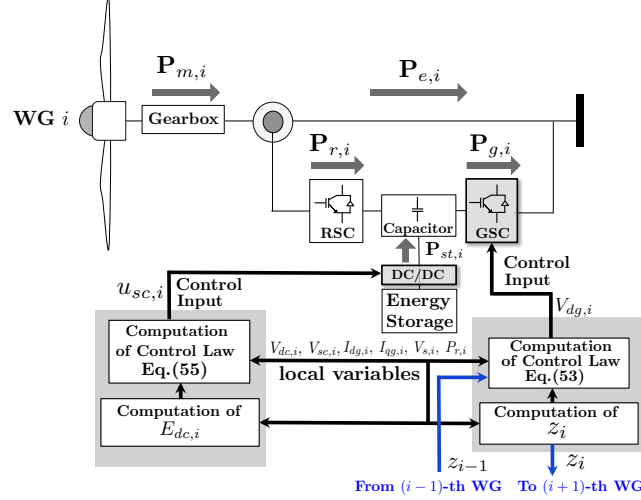


Figure 4.1: Distributed control of SoA wind DFIG with integrated energy storage

Interfacing capacitor model

An interfacing capacitor can be modeled through the dynamics of its DC voltage as:

$$(C_{dc,i}V_{dc,i})\frac{dV_{dc,i}}{dt} = (P_{r,i} + P_{st,i} - P_{g,i}), \quad \forall i \in \mathcal{G} \quad (4.2)$$

The constants $C_{dc,i}, V_{dc,i} \in \mathbb{R}$ represent the capacitance and DC voltage of the capacitor. Further, the variables $P_{g,i}$, $P_{r,i}$ and $P_{st,i}$ denote the power outputs of the GSC, the RSC, and the storage, respectively.

Supercapacitor (energy storage) model

We have particularly chosen supercapacitors as they have high efficiency and small reaction time-constant. Supercapacitors can be modeled as follows.

$$(C_{sc,i}V_{sc,i})\frac{dV_{sc,i}}{dt} = V_{sc,i}\frac{(u_{sc,i} - V_{sc,i})}{R_{sc,i}}, \quad \forall i \in \mathcal{G} \quad (4.3)$$

The variable $u_{sc,i} \in \mathbb{R}$ denotes the voltage input which is controlled by the DC-DC converter, and $C_{sc,i}, V_{sc,i}, R_{sc,i} \in \mathbb{R}_+$ denote the supercapacitor's capacitance, DC voltage and resistance, respectively. The storage power output in terms of $u_{sc,i}$ can be expressed as:

$$P_{st,i} = \frac{V_{sc,i}}{R_{sc,i}}(V_{sc,i} - u_{sc,i}), \quad \forall i \in \mathcal{G} \quad (4.4)$$

One can easily see that, this power output can be modified solely by the DC-DC converter.

4.3 Problem formulation

Consider the following setting. A WF with n WGs that incorporate supercapacitors is committed to the ISO for the provision of total power P_d . This schedule is issued by the ISO through the deployment of a wind forecasting method and an economic dispatch (ED) process. Sufficient

stored energy in the supercapacitors is ensured at the planning phase as part of the ED process which is repeated every 5 mins. Specifically, the planning ensures sufficient stored energy in the devices for effectively attaining real-time WF power output regulation, by taking into account the uncertainty about the expected wind power realization over the next look-ahead 5-min time window. Presuming sufficient energy reserves in the supercapacitors, our main problem can be formulated as follows: *To design an algorithm to control the storage devices in a distributed and coordinated way so that they collectively ensure real-time regulation of the WF's power output to a given reference P_d while the contribution of each device's power output is equal.* Below, we analyze several cases to provide more insight on the mechanics involved in attaining real-time WF power output regulation with the assistance of storage devices. First, we analyze the case where the storage devices are inactive and their power output is zero, i.e $P_{st,i} = 0, \forall i$ (Fig. 4.1). In this case, enforcing power balance at interfacing capacitor depicted in Fig. 4.1 leads to:

$$P_{g,i} = P_{r,i} + P_{st,i} \xrightarrow{P_{st,i}=0} P_{g,i} = P_{r,i}, \quad i \in \mathcal{G} \quad (4.5)$$

This is translated to the GSC power output being equal to the RSC power output. Moreover, the sum of the stator and rotor power outputs $P_{e,i}$ and $P_{r,i}$ approximately equals the mechanical power extracted from the wind $P_{m,i}$, i.e $P_{e,i} + P_{r,i} \approx P_{m,i}$. It follows immediately that, the total electrical power output of the WF is approximately equal to the total mechanical power:

$$\sum_{i \in \mathcal{G}} (P_{e,i} + P_{r,i}) \approx \sum_{i \in \mathcal{G}} P_{m,i} \quad (4.6)$$

Bearing in mind that the latter is highly volatile, one can realize that the WF's total power output will also be highly volatile. This constitutes the primary reason that can render the WF unable to meet its power commitment. Another reason is that there exists a significant time-delay between the moment the ISO issues the schedule P_d and the moment that it is physically implemented by the WF. This delay, together with the minute-to-minute variability of the wind speed, might in fact result in having:

$$\sum_{i \in \mathcal{G}} (P_{e,i} + P_{r,i}) < P_d \quad (4.7)$$

On the contrary, in the case where the storage devices participate in the WF power output regulation, the WF will be able to meet its power commitment even when the power emanating from the wind is insufficient. In this case, we will have:

$$\sum_{i \in \mathcal{G}} (P_{e,i} + P_{r,i} + P_{st,i}) = P_d \quad (4.8)$$

This can be realized by having each storage device generating (or drawing) power, in steady-state, equal to:

$$P_{st,i} = (P_{g,i} - P_{r,i}), \quad i \in \mathcal{G} \quad (4.9)$$

Hence, the storage devices can act both as sources and sinks of energy with the ultimate goal of driving the total power to the reference P_d . The total power commitment will be met when the aggregate storage power satisfies the equation:

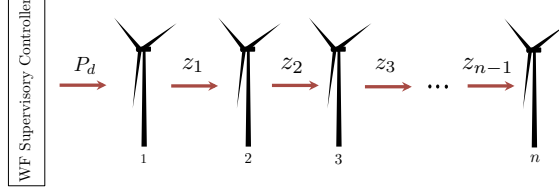


Figure 4.2: Allowable communication between WGs

Condition 1 (Total storage power reference tracking).

$$\sum_{i \in \mathcal{G}} P_{st,i} = P_d - \sum_{i \in \mathcal{G}} (P_{e,i} + P_{r,i}) \quad (4.10)$$

Beyond meeting the WF's power commitment P_d , another requirement that we impose on the storage devices is that they contribute equally to this goal. The reason behind imposing such a constraint is to accommodate fair utilization of the storage devices. This is of practical importance as the amount of power that these devices are generating determines the electrical loading experienced by their power electronics. In fact, the above requirement appears very often when dealing with power electronics because it guarantees that the total electrical loading is evenly distributed among them and that the endured wear and tear is comparable. Very commonly, this requirement appears as a control objective for photovoltaic generators. In our case, the load-sharing requirement can be translated into the following condition.

Condition 2 (Load-sharing (consensus) among storage devices).

$$P_{st,i} = P_{st,j}, \quad \forall i, j \in \mathcal{G} \quad (4.11)$$

With the two primary control objectives (meeting Conditions 1, 2) having been analyzed, the main problem can be stated as follows.

Problem 1. *Coordinate and control the energy storage devices and GSCs of a fleet of SoA WGs in a distributed way so that they attain real-time WF power output regulation with load-sharing.*

4.4 A consensus approach to distributed control

Our proposed control approach for solving Problem 1 is outlined below, partitioned into five main steps.

- **Step 1:** We pose Problem 1 as a twofold control problem, a constrained consensus problem for the GSCs with variables of interest $z_i \triangleq (P_{g,i} - P_{r,i})$, i.e the mismatch between the GSCs' and RSCs' power outputs, and a tracking control problem for the DC-DC converters where variables of interest are the storage power outputs $P_{st,i}$ with objective $\lim_{t \rightarrow \infty} P_{st,i}(t) = z_i, \forall i$.
- **Step 2:** We introduce a leader-follower consensus protocol that GSCs can implement through their control systems to drive their z_i to a common value (consensus), and a closed-loop form for the interfacing capacitor dynamics that DC-DC converters can implement through their control system to enable the variables $P_{st,i}$ to attain reference tracking.

- **Step 3:** We perform timescale separation analysis of the coupled closed-loop dynamics of the consensus protocol and the interfacing capacitor, deriving explicit conditions that the control gains of the GSCs and DC-DC converters have to satisfy in order for these dynamics to manifest three distinct timescales.
- **Step 4:** We let the control gains of all the converters fulfill the Conditions in Step 3. Given that, we establish asymptotic stability of the closed-loop dynamics by leveraging temporal decomposition and compositional stability analysis tools.
- **Step 5:** We design a distributed controller for the GSC which leads to the closed-loop dynamics of z_i matching the consensus protocol dynamics and a CLF-based controller for the DC-DC converter which ensures that the closed-loop dynamics of the capacitor take the desired form stated in Step 2.

4.5 Reducing the control problem to equivalent subproblems

Real-time WF power output regulation with load-sharing is formulated in Section 4.3 as a control problem for the storage devices with objective to meet *Conditions* 1 and 2. Here, we propose the following approach for meeting these conditions: dynamically regulate each power output $P_{st,i}$ to z_i , i.e ensure that $P_{st,i} \rightarrow (P_{g,i} - P_{r,i})$, and coordinate the GSCs so that their controlled-variables z_i satisfy the next two conditions.

Condition 3 (Total power reference tracking).

$$\sum_{i \in \mathcal{G}} z_i = \left(P_d - \sum_{i \in \mathcal{G}} (P_{e,i} + P_{r,i}) \right) \quad (4.12)$$

Condition 4 (Consensus among z_i).

$$z_i = z_j, \quad \forall i, j \in \mathcal{G} \quad (4.13)$$

Using these two conditions, our main problem can be reduced to two equivalent control subproblems; the first one is for the GSCs to attain restricted consensus among all z_i and the second one for the DC-DC converters to regulate the storage power outputs $P_{st,i}$ to their respective z_i .

Problem 2 (Constrained Consensus among z_i). *Coordinate and control the GSCs so that the variables z_i asymptotically converge to a common value (consensus), i.e fulfill Condition 4, while the constraint given in Condition 3 is met.*

Problem 3 (Storage Power Outputs Reference Tracking). *Control each storage device $i \in \mathcal{G}$ so that its power output $P_{st,i}$ is regulated to its respective z_i , i.e $\lim_{t \rightarrow \infty} P_{st,i}(t) = z_i$.*

4.6 Consensus protocol and proposed closed-loop form of capacitor's dynamics

Next, a consensus protocol is presented, that the GSCs can adopt to self-organize and drive their z_i to consensus, and a proposed closed-loop form for the capacitors' dynamics that can enable the power outputs of the storage devices $P_{st,i}$ to attain reference tracking.

Leader-Follower Consensus Protocol

Without loss of generality we choose WG l , where $l \triangleq 1$, as the leader, and describe the followers with the set $\overline{\mathcal{G}} \triangleq \mathcal{G} \setminus l$. Our proposed leader-follower consensus protocol is described through the dynamical equations below.

Consensus Protocol $\mathcal{P}_1$

Leader

$$\frac{d\xi_h}{dt} = \left(P_d - \sum_{i \in \mathcal{G}} (P_{e,i} + P_{r,i} + z_i) \right) \quad \xi_h \in \mathbb{R} \quad (4.14a)$$

$$\frac{dz_l}{dt} = -k_{\alpha,l}(z_l - \xi_h), \quad z_l \in \mathbb{R}, \quad z_l \triangleq z_1 \quad (4.14b)$$

Followers

$$\frac{dz_i}{dt} = -k_{\alpha,i}(z_i - z_{i-1}), \quad z_i \in \mathbb{R}, \quad \forall i \in \overline{\mathcal{G}} \quad (4.14c)$$

The protocol's states are the variables z_i and the auxiliary variable of the leader ξ_h . The variable ξ_h is the one that “drives” the protocol dynamics and guarantees regulation of the total WF power to the reference P_d . Notice that every WG is allowed to communicate with a single neighboring WG.

The protocol $\mathcal{P}_1$ is executed through the following mechanism. The leader WG receives information about the reference P_d from the WF supervisory controller while, at the same time, it communicates to its neighbor (WG 2) the variable z_1 . Synchronized with the leader, each follower i receives from its neighbor $(i-1)$ the variable z_{i-1} and communicates to its neighbor $(i+1)$ the variable z_i . Upon receiving P_d , the leader combines that with the information $\sum_{i \in \mathcal{G}} (P_{e,i} + P_{g,i})$ that can be retrieved locally and updates both the state-variables ξ_h and z_1 through equations (4.14a) and (4.14b). Similarly, each follower i , upon receiving z_{i-1} , updates its corresponding z_i through equation (4.14c). Next, the performance on Protocol $\mathcal{P}_1$ under communication link and agent failures is discussed.

Performance under communication link or agent failures

The proposed consensus protocol relies on a row-connected communication network topology which offers low levels of robustness with respect to communication link and agent failures. Specifically, if one communication link or an agent is compromised the protocol cannot reach convergence with the total number of agents participating even when the failure is detected and the control logic of several agents is modified. This can happen because the agents that are connected after the receiving node of the affected link (or agent) will be left uncoordinated after the failure. On the other hand, communication networks with redundant number of links can offer higher levels of robustness to such failures and can yield convergence of the protocol with the total number of agents participating, in the case of a link failure, and with all but the affected agent participating, in the case of an agent failure. However, this can be realized presuming that the failures can be detected and the control logic of several affected agents can be modified accordingly. Our control

approach can be easily adapted to accommodate such communication network topologies. Regarding the requirement for modifying the control logic of several agents after a link or agent failure, we underline that this is a general limitation present in most, if not in all, distributed control algorithms. Its presence is due to the fact that the performance of these algorithms relies heavily on the ability of all agents to update/control certain state-variables and exchange information reliably.

Proposed closed-loop form of capacitor's dynamics

Our proposed closed-loop form for the interfacing capacitor's dynamics, stated in terms of the variable $\Delta E_{dc,i} \triangleq (E_{dc,i} - E_{dc0,i})$ that denotes deviation of the capacitor's stored energy level from its equilibrium, can be written as:

$$\frac{d(\Delta E_{dc,i})}{dt} = -k_{2,i}(\Delta E_{dc,i}), \quad \forall i \in \mathcal{G} \quad (4.15)$$

The DC-DC converters can shape the closed-loop capacitors' dynamics so that they acquire this form, enabling the storage power output $P_{st,i}$ to track the variable z_i . To see that, consider the open-loop dynamics of the stored energy as:

$$\frac{d(\Delta E_{dc,i})}{dt} = (P_{r,i} + P_{st,i} - P_{g,i}), \quad \forall i \in \mathcal{G} \quad (4.16)$$

With the closed-loop dynamics of the capacitor taking the form (4.15), the dynamics of the storage device's power output $x_i \triangleq P_{st,i}$ can be derived as follows. First, let (4.15) be equal to (4.16), differentiate both sides of the resulting equation and substitute dz_i/dt from (4.14c). This will eventually yield:

Storage Power Dynamics

$$\frac{dx_i}{dt} = -k_{\alpha,i}(z_i - z_{i-1}) - k_{2,i}(x_i - z_i), \quad \forall i \in \mathcal{G} \quad (4.17)$$

Observe that, when the protocol is at equilibrium, the above equation yields $x_i = z_i$ which means the storage device's power output equals z_i . The protocol dynamics in (4.14b) and (4.14c) serve as the desired closed-loop dynamics for z_i and can be realized by the GSCs, while the dynamics in (4.17) serve as the desired closed-loop dynamics for x_i and can be realized by the DC-DC converters. The overall system comprised of the coupled protocol dynamics and the closed-loop storage power dynamics, can be described by equations (4.14a)-(4.14c) and (4.17).

4.7 Numerical results

In this section, we evaluate the performance of the controllers and the effectiveness of the consensus protocol and closed-loop form of capacitor dynamics in resulting in WF power output regulation with load-sharing. For this scope, a modified version of the IEEE 24-bus reliability test system is used, where, at bus 22, a row-connected WF comprised of 10 SoA WGs with supercapacitors is placed. The network topology that characterizes the communication links among the WGs is depicted in Fig. 4.8b. The GSCs and DC-DC converters of all WGs adopt respectively, the proposed distributed control law and the CLF-based control law. Numerical simulations are conducted under the following representative scenarios.

- *Scenario 1:* The WF power reference P_d is constant (see Fig. 4.3a).
- *Scenario 2:* The WF power reference P_d varies in a step-wise manner (see Fig. 4.5a).

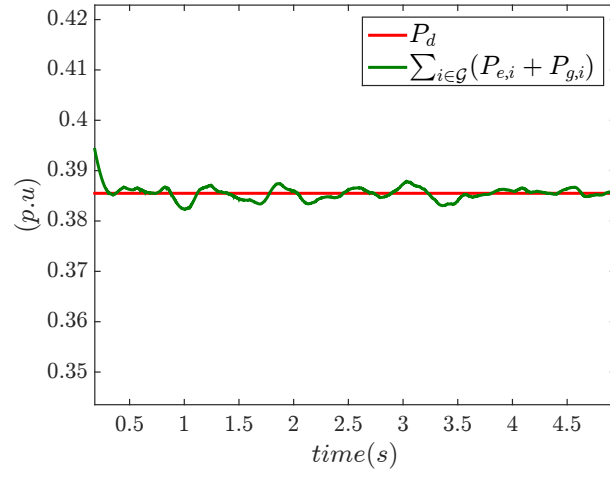
The results under Scenario 1 are discussed first. Observe from Fig. 4.3a that the total WF power output is tightly confined around P_d . This is accomplished through the rapid convergence of the GSC-controlled variables $\mathbf{z}$ and storage power outputs $\mathbf{x}$ to ξ_h (consensus) which, on a slower timescale, converges to ξ_{h0} , as depicted in Fig. 4.3b and Fig. 4.4a, respectively. The variations of the stored energy levels in the supercapacitors are depicted in Fig. 4.4b. Altogether, the results verify that WF power output regulation with load-sharing of the storage devices is carried out effectively in this Scenario.

Moving forward, the results under Scenario 2 are discussed. From Fig. 4.5a, one can observe that the proposed distributed controllers attain WF power reference tracking with good performance as the total WF power rapidly and closely tracks the fast-varying reference P_d .

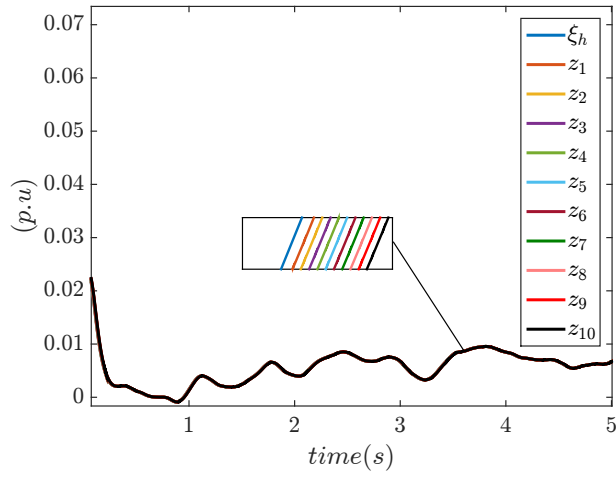
In Fig. 4.5b, observe the dynamic responses of the variables z_i which are driven by the regulation of the GSCs' power outputs through the proposed protocol in response to changes in the reference. These variables manifest indistinguishable trajectories (see Fig. 4.5b) as they all reach consensus rapidly and converge to the variable ξ_h which varies on a slower timescale. On this slow timescale, ξ_h converges to the equilibrium ξ_{h0} (which depends on P_d) driving the variables $\mathbf{z}$ to the equilibrium ξ_{h0} as depicted in Fig. 4.5b. In particular, observe that the variables $\mathbf{z}$ and ξ_h are concurrently driven to the quasistatic equilibrium ξ_{h0} while consensus among them is already attained. Finally, the variations of the stored energy levels in the supercapacitors under this Scenario are depicted in Fig. 4.7.

The responses of the variables $\mathbf{x}$ match one-to-one the responses of the variables $\mathbf{z}$, manifesting indistinguishable trajectories, as seen in Fig. 4.6a. This is explained as follows. The DC-DC converters, through their controllers, regulate the storage power outputs $\mathbf{x}$ to their corresponding $\mathbf{z}$ in order to provide the power demanded by the GSCs to attain WF power output regulation. This action indirectly leads to the storage power outputs $\mathbf{x}$ reaching consensus as well, achieving that way the load-sharing objective.

In conclusion, the distributed controllers, by realizing the proposed consensus protocol and closed-loop capacitor's dynamics, effectively carried out WF power output regulation with power-sharing among storage devices.

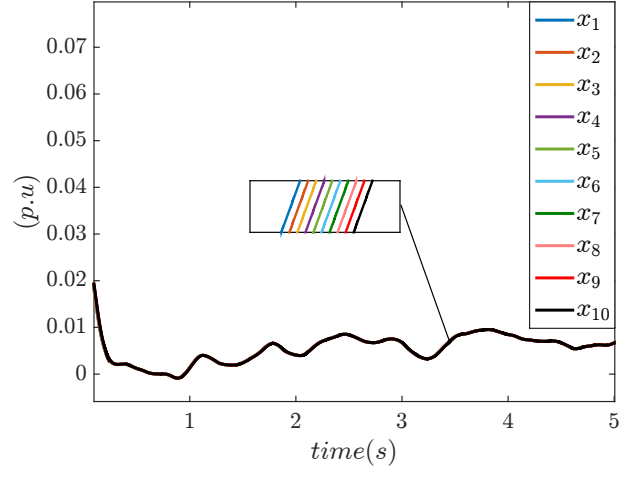


(a)

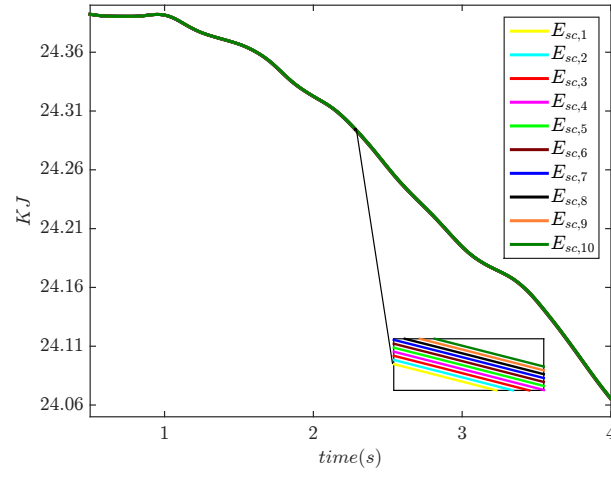


(b)

Figure 4.3: *Scenario 1* a) WF total power output, b) State-variables z_i

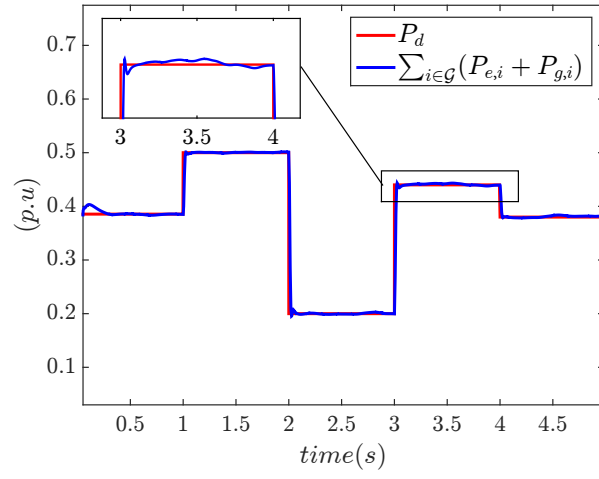


(a)

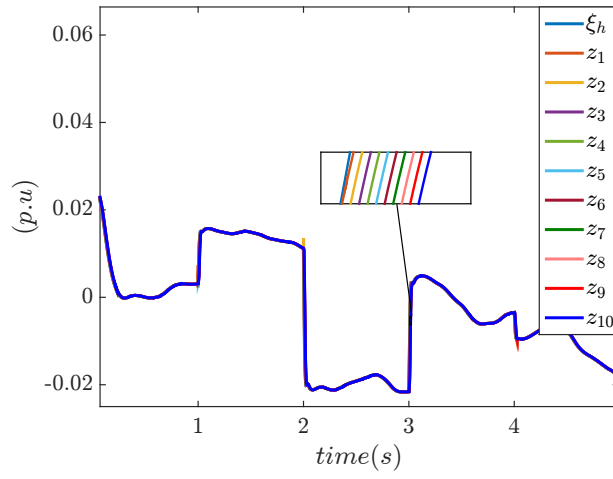


(b)

Figure 4.4: *Scenario 1* a) Storage power outputs x_i , b) Energy levels $E_{sc,i}$ with $V_{sc,i} = 1kV$, $C_{sc,i} = 50mF$, $i = 1, \dots, 10$

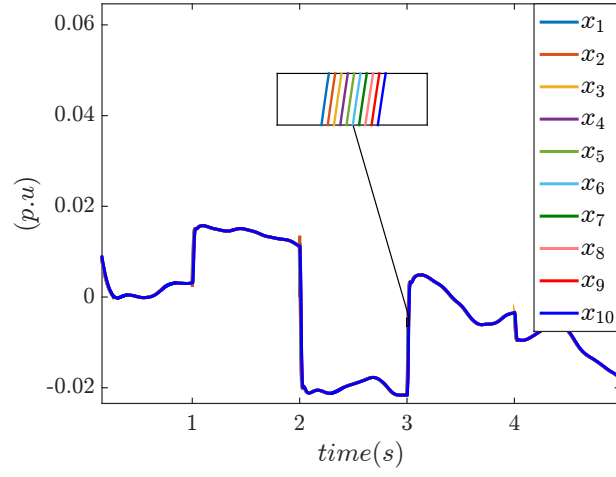


(a)

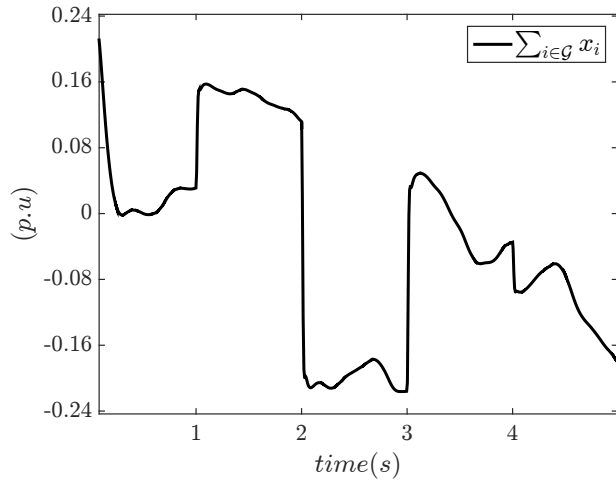


(b)

Figure 4.5: *Scenario 2* a) WF power output (blue) and reference (red), b) z_i



(a)



(b)

Figure 4.6: *Scenario 2* a) Storage power outputs x_i , b) Total storage power

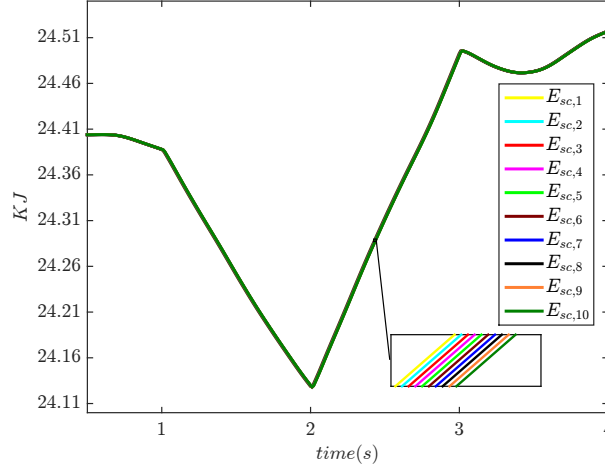


Figure 4.7: *Scenario 2* Energy levels $E_{sc,i}$ with $V_{sc,i} = 1kV$, $C_{sc,i} = 50mF$, $i = 1, \dots, 10$

4.8 Distributed torque control of deloaded wind DFIGs for wind farm power output regulation

In today's power systems, WGs are often operated in a deloaded regime, extracting less power than the maximum available from the wind. When WGs are being operated in such regime, they are able to increase their power output when needed in order to provide frequency regulation for example. In the operation of large wind farms (WFs) comprised of numerous WGs being operated in a deloaded regime, a challenge that arises is to define the set-points of these WGs. In other words, to dispatch a group of WGs based on the required total WF power and according to the local wind speed conditions (to each WG), in a timely, robust and computation-ally efficient fashion: timely, since in the future, WFs will have to respond faster to maintain supply-demand balance, especially in microgrid settings; robust, such that the performance of WFs is also reliable and computation-ally efficient to support timely and cost-effective operation (especially when the number of WGs is very large). Current approaches that address the above problem are centralized, meaning that information from each WG is communicated to a central WF controller. These approaches are prone to single-point failures, require high computational effort, extensive communication infrastructure and might not be able to respond timely. In our work, we effectively addressed the above problem by developing a novel distributed control architecture for deloaded WGs, elaborated below.

In our paper “Distributed Torque Control of Deloaded Wind DFIGs for Wind Farm Power Output Regulation”, whose main ideas and results we present below, we introduced a novel distributed control architecture that WGs can adopt to dynamically self-dispatch themselves, ensuring that: their total extracted power from the wind matches a given reference and their utilization levels are the same (i.e load-sharing). More specifically, we developed a Control Lyapunov Function-based torque controller for the rotor-side power electronics of WGs that implements the proposed protocol. The proposed control architecture: 1) can dispatch a group of WGs based on local wind-speed conditions eliminating the need for a central wind farm controller and leading to low computational cost; 2) requires minimum peer-to-peer communication among neighboring WGs; 3) enables WGs to be dispatched timely which is critical since dispatching is performed under fast-varying dy-

namical wind and loading conditions to balance supply-demand (especially in autonomous power systems such as microgrids); 4) has guaranteed stability and performance.

Our work is the first work to systematically and effectively solve the problem of dispatching a group of deloaded WGs in a distributed, dynamic and efficient manner. In contrast with previous work, our method is dynamic in the sense that the proposed power electronics WG controllers reach consensus dynamically according to a given reference. We emphasize that the problem of dispatching WGs efficiently and distributively is as critical as solving the Economic Dispatch (ED) problem of SGs in a distributed fashion, which has already attracted a lot of attention in the power systems and control communities. Therefore, our work provides the first steps in this direction. Below, we outline the main ideas and results obtained in this direction.

4.9 Dynamical modeling

We consider control of the rotor-side dynamics, therefore, we only present the dynamical models associated with the rotor. These can be fully described by three ordinary differential equations (ODEs) which represent the internal rotor-voltages dynamical model with the RSC control input and the rotor-speed dynamical model of each DFIG. The set of deloaded WGs is denoted by $\mathcal{G} \triangleq \{1, \dots, n\}$ and each WG is indexed by i so that $i \in \mathcal{G}$.

4.9.1 Internal rotor voltages dynamical model

The first two equations describe the dynamics of the internal rotor-voltages and can be stated as:

$$\begin{aligned} \dot{E}'_{d,i} = \frac{1}{T'_{0,i}} \left[-(E'_{d,i} - (X_{s,i} - X'_{s,i})I_{qs,i}) + T'_{0,i}(-\omega_s \frac{X_{m,i}}{X_{r,i}} V_{qr,i} \right. \\ \left. + (\omega_s - \omega_{r,i})E'_{q,i}) \right], \quad i \in \mathcal{G} \end{aligned} \quad (4.18a)$$

$$\begin{aligned} \dot{E}'_{q,i} = \frac{1}{T'_{0,i}} \left[-(E'_{q,i} + (X_{s,i} - X'_{s,i})I_{ds,i}) + T'_{0,i}(\omega_s \frac{X_{m,i}}{X_{r,i}} V_{dr,i} \right. \\ \left. - (\omega_s - \omega_{r,i})E'_{d,i}) \right], \quad i \in \mathcal{G} \end{aligned} \quad (4.18b)$$

We underline that the rotor-voltage dynamics are given in a $d-q$ coordinate system, where d is the axis that is aligned with the terminal voltage phasor vector, and q is the axis that is orthogonal to d .

4.9.2 Rotor speed dynamical model

The rotor speed dynamics can be described by:

$$\dot{\omega}_{r,i} = \frac{\omega_s}{2H_i} (T_{m,i} - T_{e,i}), \quad i \in \mathcal{G} \quad (4.18c)$$

where the mechanical torque can be expressed analytically as:

$$T_{m,i} \triangleq \frac{1}{2} \frac{\rho \pi R_i^2 \omega_s}{S_{b,i} \omega_{r,i}} C_p(\lambda_i, \theta_i) v_{w,i}^3, \quad i \in \mathcal{G} \quad (4.18d)$$

The power coefficient $C_{p,i}$ can be expressed in terms of the pitch angle θ_i and tip-speed λ_i as:

$$C_{p,i} \triangleq 25.52 \left[\left(\frac{1}{\lambda_i + 0.08\theta_i} - \frac{0.035}{\theta_i^3 + 1} \right) \right] \cdot e^{-12.5 \left(\frac{1}{\lambda_i + 0.08\theta_i} - \frac{0.035}{\theta_i^3 + 1} \right)} \quad (4.18e)$$

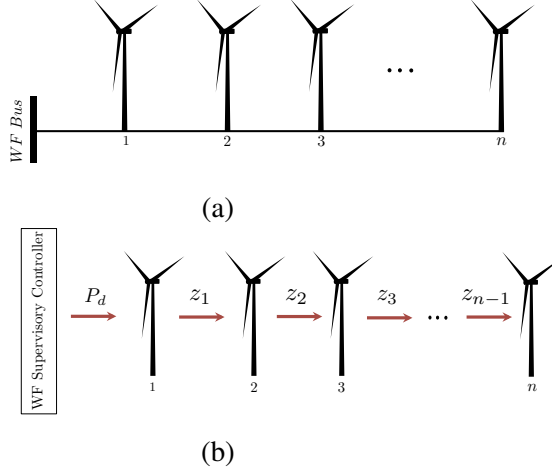


Figure 4.8: a) Physical topology b) Communication topology of WF

Finally, in terms of rotor speed and wind speed, the tip-speed can be expressed as:

$$\lambda_i \triangleq \frac{2k_i}{p_i} \frac{\omega_{r,i} R_i}{v_{w,i}}, \quad i \in \mathcal{G} \quad (4.18f)$$

The mechanism through which the RSC adjusts the mechanical power can be explained by focusing on the last three equations. Concretely, the RSC regulates the rotor speed $\omega_{r,i}$ through which it adjusts the power coefficient $C_{p,i}$, and eventually the mechanical torque $T_{m,i}$.

4.10 Problem formulation

Here, we study a wind farm comprised of n wind generators operating in a deloaded mode. The mechanical power extracted from the wind by each WG i is determined by equation:

$$P_{m,i} \triangleq \frac{1}{2} \rho C_{p,i} A_i v_{w,i}^3, \quad i \in \mathcal{G} \quad (4.19)$$

where $C_{p,i} \in \mathbb{R}_+$ is the power coefficient, $\rho \in \mathbb{R}_{++}$ the air density (kg/m^3), $v_{w,i} \in \mathbb{R}_{++}$ the wind speed in (m/s) and $A_i = \pi R_i^2 \in \mathbb{R}_{++}$ the area swept by the blades with $R_i \in \mathbb{R}_+$ being the blade radius. Notice that, the only controllable variable in (4.19) is $C_{p,i}$, which can be regulated by the WG through variation of the rotor speed $\omega_{r,i}$. When the wind speed is low, DFIGs are usually operated under a Maximum Power Point Tracking (MPPT) strategy. Under this strategy, a wind DFIG is controlled so that $C_{p,i} = \bar{C}_{p,i}$, where $\bar{C}_{p,i} = \max_{\lambda_i} \{C_{p,i}(\lambda_i, \theta_i^*)\}$ and so that $P_{m,i}$ in (4.19) equals:

$$\bar{P}_{m,i} \triangleq \frac{1}{2} \rho \bar{C}_{p,i} A_i v_{w,i}^3, \quad i \in \mathcal{G} \quad (4.20)$$

The constant $\bar{C}_{p,i}$ denotes the maximum value of the power coefficient, so it holds that $C_{p,i} \in [0, \bar{C}_{p,i}]$. In our case, the DFIGs operate in a deloaded mode so that $C_{p,i} < \bar{C}_{p,i}$, $P_{m,i} < \bar{P}_{m,i}$, $\forall i \in \mathcal{G}$. Thus, they can be controlled through their RSCs so that they vary their power coefficients in the above range and their corresponding mechanical power $P_{m,i}$ takes values in the continuous set

$[0, \bar{P}_{m,i}]$. The only requirement is that the total mechanical power has to be equal to the total power reference P_d which corresponds to the power that the WF is committed to supply to the grid in a 5-minute time-window. This reference comes from the system operator (SO) and is the outcome of a wind forecasting and an economic dispatch (ED) process conducted every several minutes. Here, we assume that the reference satisfies $P_d \leq \sum_{i \in \mathcal{G}} \bar{P}_{m,i}$, i.e that it is realizable by the WGs, considering the current prevalent local wind-speed conditions. We note that the deloaded DFIGs can meet any total power request P_d as long as $P_d \in [0, \sum_{i \in \mathcal{G}} \bar{P}_{m,i}]$. Nevertheless, extensive wear and tear on the shafts of the WGs can be avoided when the reference P_d is sufficiently slow-varying so that the WGs are not called to regulate their power outputs very fast.

For our setting, the general power dispatch and regulation problem can be formulated as: *given $v_{w,i}$, $\forall i \in \mathcal{G}$ and P_d , compute the set-points $P_{m,i}^* \in [0, \bar{P}_{m,i}]$, $C_{p,i}^* \in [0, \bar{C}_{p,i}]$ for all WGs and regulate their mechanical power outputs such that $\lim_{t \rightarrow \infty} \sum_{i \in \mathcal{G}} P_{m,i}(t) = \sum_{i \in \mathcal{G}} P_{m,i}^* = P_d$.* Observe that there exist multiple combinations of set-points that satisfy the above constraints, in fact, any power dispatch $(P_{m,1}^*, \dots, P_{m,n}^*)$ that respects the above conditions is realizable. On the other side, when the set-points are required to also satisfy $(P_{m,1}^*/\bar{P}_{m,1}) = \dots = (P_{m,n}^*/\bar{P}_{m,n})$ this combination becomes unique. Note that the latter requirement is common when dispatching WGs, since it guarantees more efficient operation. In particular, each WG will contribute to the total power output analogously to the available wind speed potential at its location. Often, the same requirement is imposed when dispatching photovoltaic generators. A dispatch that satisfies this requirement is known as “*fair dispatch*” since the power outputs of the WGs are proportional to their maximum values which depend on the local wind speed conditions i.e WGs operate under the same loading levels (fair load-sharing). In summary, the conditions power outputs of WGs have to meet to realize a fair dispatching scenario can be formally stated as follows.

Condition 5 (Total power output regulation).

$$\sum_{i \in \mathcal{G}} P_{m,i}^* = P_d \quad (4.21a)$$

Condition 6 (Fair load-sharing).

$$\frac{P_{m,i}^*}{\bar{P}_{m,i}} = \frac{P_{m,j}^*}{\bar{P}_{m,j}}, \quad i, j \in \mathcal{G} \quad (4.21b)$$

The following definition can now be stated.

Definition 1. A power dispatch $\mathbf{P}_m^* = [P_{m,1}^*, \dots, P_{m,n}^*]^\top$ that satisfies both Conditions 5 and 6, is called a *fair dispatch*.

At this point, we state the following remark.

Remark 1.

$$\frac{P_{m,i}^*}{\bar{P}_{m,i}} = \frac{C_{p,i}^*}{\bar{C}_{p,i}}, \quad i \in \mathcal{G} \quad (4.22)$$

The ratio $(C_{p,i}^*/\bar{C}_{p,i})$ corresponds to the utilization (or loading level) of each WG. By employing Remark 1, which is directly obtained by taking the ratio of (4.19) and (4.20), Condition 6 can be substituted by the new and equivalent condition below.

Condition 7 (Fair load-sharing).

$$\frac{C_{p,i}^*}{\bar{C}_{p,i}} = \frac{C_{p,j}^*}{\bar{C}_{p,j}}, \quad i, j \in \mathcal{G}$$

Using the above conditions, we formulate the main problem as follows.

Problem formulation (*WF Power Output Regulation via Distributed Fair Dynamic Dispatching and Regulation of WGs' Power Outputs*). Develop a distributed control design for the RSCs which leverages limited communication to dynamically dispatch and regulate the power outputs of WGs such that these meet Conditions 5 and 7.

Traditionally, this problem is addressed through centralized control approaches. In these approaches, WGs first communicate their wind-speed measurements to a central WF controller which then computes the power set-points for the individual WGs so that these meet the above two conditions. Finally, the WF controller communicates the computed set-points to the WGs. This paper provides a distributed solution to this problem with the control methodology introduced next.

4.11 Distributed control approach

To solve the main problem, WGs have to guarantee in a distributed manner (using peer-to-peer communication) that their utilization levels $C_{p,i}/\bar{C}_{p,i}$ asymptotically converge to a common value, while their total power tracks the reference P_d , i.e that Conditions 5 and 7 are fulfilled. This problem can be naturally posed as a *constrained consensus problem* among WGs, where they have to reach consensus on their utilization levels $C_{p,i}/\bar{C}_{p,i}$ under the constraint that their total power matches the reference P_d . WGs can accomplish these objectives by deploying a properly designed consensus protocol with limited peer-to-peer communication.

4.11.1 Leader-follower consensus protocol

We propose the following *leader-follower consensus protocol* for the coordination of WGs that can be implemented by their RSCs to realize dynamic, distributed dispatch and regulation of their power outputs, leading to the Conditions 5 and 7 being satisfied asymptotically.

Consensus Protocol $\mathcal{P}_1$ Dynamics

Leader WG

$$\frac{d\xi_h}{dt} = (P_d - \sum_{i \in \mathcal{G}} P_{m,i}) \quad \xi_h \in \mathbb{R} \quad (4.23a)$$

$$\frac{dz_l}{dt} = -k_{\alpha,l}(z_l - \xi_h), \quad z_l \triangleq z_1 \quad z_l \in \mathbb{R} \quad (4.23b)$$

WG i

$$\frac{dz_i}{dt} = -k_{\alpha,i}(z_i - z_{i-1}), \quad i \in \overline{\mathcal{G}} \quad z_i \in \mathbb{R} \quad (4.23c)$$

Without loss of generality, WG 1 is assigned as the leader, i.e $l \triangleq 1$, and the set of followers is denoted by $\overline{\mathcal{G}} \triangleq \mathcal{G} \setminus \{l\} \triangleq \{2, \dots, n\}$. The consensus protocol's state-variables are the utilization levels $z_i \triangleq C_{p,i}/\overline{C}_{p,i}$ and the auxiliary variable ξ_h of the leader. Each WG is allowed to communicate with two other (physically) neighboring WGs, as shown in Figure 4.8.

The protocol is executed through the following mechanism. The supervisory WF controller obtains a total power set-point P_d from the SO and communicates it to the leader WG. Subsequently, the leader WG controls the dynamics of its state-variables z_l and ξ_h , using the reference P_d and information (retrieved distributively via indirect information passing) from all WGs, and communicates only its power coefficient z_l and the derivative of its power coefficient, $\dot{z}_l$, to its neighbors. In synchrony with the leader, all the followers control the dynamics of their state-variables z_i , and communicate their respective z_i and $\dot{z}_i$ to their $(i+1)$ neighbors. The leader has to retrieve the information $\sum_{i \in \overline{\mathcal{G}}} P_{m,i}$ as well, which is required in (4.23a). This can be done either through indirect information passing between WGs or through a much faster average consensus protocol involving the mechanical power.

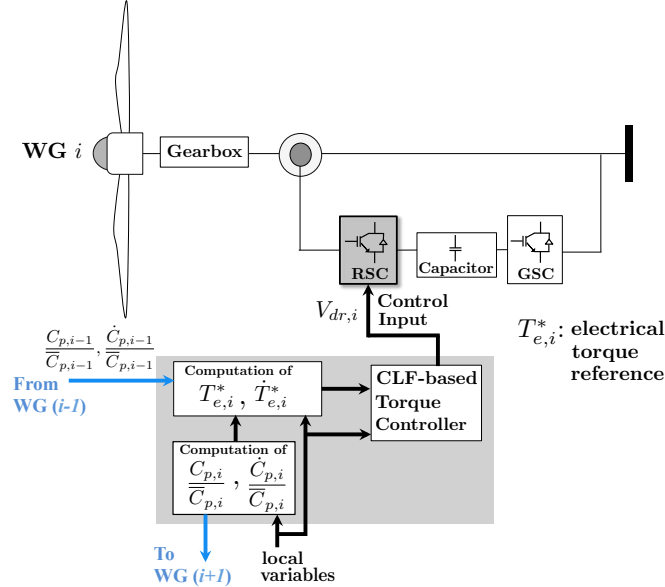


Figure 4.9: Distributed CLF-based torque controller

4.12 Case studies

We present numerical simulations under several critical scenarios in order to validate our theoretical results. The simulations are conducted in MATLAB. In particular, the simulations are performed on the modified IEEE 24-bus RT system with all the synchronous generators modeled in detail using the one-axis model and each wind DFIG modeled using the models stated in Section 4.9. The 24-bus system is modified such that, on bus 22, a WF is placed, comprised of 10 WGs (the physical and communication topologies shown in Fig. 4.8). We emphasize that all WGs are assumed to share the same technical characteristics. The initial local wind-speed conditions are assumed to be $v_{w,i} = 13.17 \text{ m/s}$ and homogeneous throughout the WF. In this set-up, the simulations are conducted with the RSC of each WG implementing the distributed CLF-based torque controller under the following critical scenarios and with the WGs initiated with non-identical $C_p/\bar{C}_p$ ratios. The goal is to comprehensively evaluate the stability and performance of the proposed protocol and corresponding distributed CLF-based torque controller.

- **Scenario 1** (WF power Reference P_d varies with constant wind speed $v_w = 13.17 \text{ m/s}$)
 - $t = 0\text{s}$: The reference is constant at $P_d = 0.38 \text{ p.u.}$
 - $t = 3\text{s}$: The reference decreases to $P_d = 0.36 \text{ p.u.}$
 - $t = 9\text{s}$: The reference increases to $P_d = 0.40 \text{ p.u.}$
- **Scenario 2** (Wind speed v_w varies with constant reference $P_d = 0.38$)
 - $t = 0\text{s}$: Wind speed is constant at $v_w = 13.17 \text{ m/s.}$
 - $t = 2\text{s}$: Wind speed decreases to $v_w = 12 \text{ m/s.}$
- **Scenario 3** (Both the WF power reference P_d and wind speed v_w vary)
 - $t = 0\text{s}$: Reference and wind speed are constant, $P_d = 0.38 \text{ p.u.}$, $v_w = 13.17 \text{ m/s.}$
 - $t = 3\text{s}$: Reference increases to $P_d = 0.40 \text{ p.u.}$
 - $t = 9\text{s}$: Wind speed increases to $v_w = 14.17 \text{ m/s.}$
 - $t = 15\text{s}$: Reference decreases to $P_d = 0.36 \text{ p.u.}$ and wind speed decreases to $v_w = 12.17 \text{ m/s.}$

At first, we elaborate on the results under *Scenario 1*. By observing Fig. 4.10b we can conclude that the WF total power output of the WF is able to effectively track the reference P_d as it varies, with good dynamic performance e.g short response time, and small overshoot. Hence, the distributed CLF-based torque controllers succeed in providing total WF power output regulation. In fact, they achieve that by dynamically redispatching and readjusting the corresponding power outputs of their WGs indirectly, through regulation of the loading levels (i.e consensus states) to their new equilibria. These equilibria depend on the reference P_d and the wind speed conditions. In our case, two new equilibria arise, one at $t = 3\text{s}$, and one at $t = 9\text{s}$, computed as:

$$\begin{aligned}
 t = 3\text{s} : \xi_{h0} &= \frac{0.36 \cdot 100 \cdot 10^6}{10 \cdot (0.5 \cdot 1.225 \cdot 0.438 \cdot \pi \cdot 52^2 \cdot 13.17^3)} = 0.6915 \\
 t = 9\text{s} : \xi_{h0} &= \frac{0.40 \cdot 100 \cdot 10^6}{10 \cdot (0.5 \cdot 1.225 \cdot 0.438 \cdot \pi \cdot 52^2 \cdot 13.17^3)} = 0.7684
 \end{aligned}$$

The “fair dispatch” or equivalently, the “fair load-sharing” among the WGs can be seen in Fig. 4.10a, where the loading levels (ratios $C_{p,i}/\bar{C}_{p,i}$) converge to a common value soon after each perturbation. This is accomplished through the following mechanism. In the fast time-scale, the ratios $C_{p,i}/\bar{C}_{p,i}$ reach consensus and rapidly converge to the auxiliary state-variable ξ_h of the leader, where ξ_h can be thought of as a quasistatic equilibrium for the fast state-variables $C_{p,i}/\bar{C}_{p,i}$. On the other hand, in the slow time-scale, the state-variable ξ_h converges to its equilibrium ξ_{h0} , which depends on the new reference P_d , as depicted in Fig. 4.10a. The convergence of ξ_h drives the state-variables $C_{p,i}/\bar{C}_{p,i}$ to eventually converge to the equilibrium of ξ_h , ξ_{h0} .

The intuition driving the execution of the protocol and the numerical simulations under *Scenario 1* can be explained as follows. First, the leader WG senses the variations of P_d through its auxiliary state-variable ξ_h which decreases and increases at $t = 3s$ and at $t = 9s$, respectively. Correspondingly, the leader’s consensus state-variable z_l , by tracking ξ_h , decreases at $t = 3s$ and increases at $t = 9s$. In a concurrent and synchronized manner, the followers decrease and then increase their utilization levels (consensus states) in order to reach consensus with the leader. Combined, these actions lead to the loading levels converging to 0.6915 after 3s and to 0.7684 after 9s, while their initial value is 0.73 (Fig. 4.10a). Practically, the distributed CLF-based torque controllers regulated the loading levels by initially accelerating and then decelerating their turbines as shown in Fig. 4.10c. These adjustments of the rotor speeds enable the WGs to reduce and then increase their mechanical power outputs so that their total power output tracks the desired power reference in both cases (Fig. 4.10b).

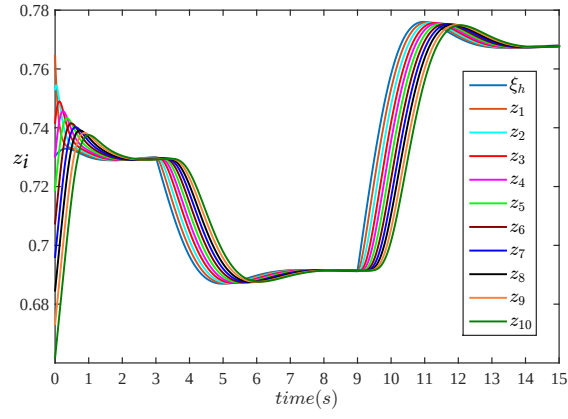
Moving to the simulation results under *Scenario 2*, we can observe from Fig. 4.11b that the total mechanical power $\sum_{i \in \mathcal{G}} P_{m,i}$ is initially constant, while after the sudden drop in the wind-speed it dives to a lower value. The equilibrium of the WGs’ loading levels and the auxiliary state-variable ξ_h , before the wind-speed disturbance (i.e in $t \in [0, 2s]$), is:

$$\xi_{h0} = \frac{P_d}{\sum_{i=1}^{10} \alpha_i} = \frac{0.38 \cdot 100 \cdot 10^6}{10 \cdot (0.5 \cdot 1.225 \cdot 0.438 \cdot \pi \cdot 52^2 \cdot 13.17^3)} = 0.729$$

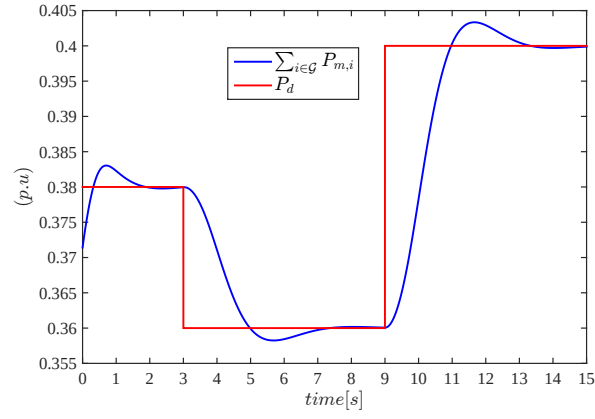
The loading levels starting from non-equal values converge to this equilibrium asymptotically during the first 2 seconds, as can be seen in Fig. 4.11a. Subsequently, the leader senses the wind-speed drop through the dynamics of the auxiliary variable ξ_h whose equilibrium, also that of the loading levels, changes to:

$$\xi_{h0} = \frac{P_d}{\sum_{i=1}^{10} \alpha_i} = \frac{0.38 \cdot 100 \cdot 10^6}{10 \cdot (0.5 \cdot 1.225 \cdot 0.438 \cdot \pi \cdot 52^2 \cdot 12^3)} = 0.965$$

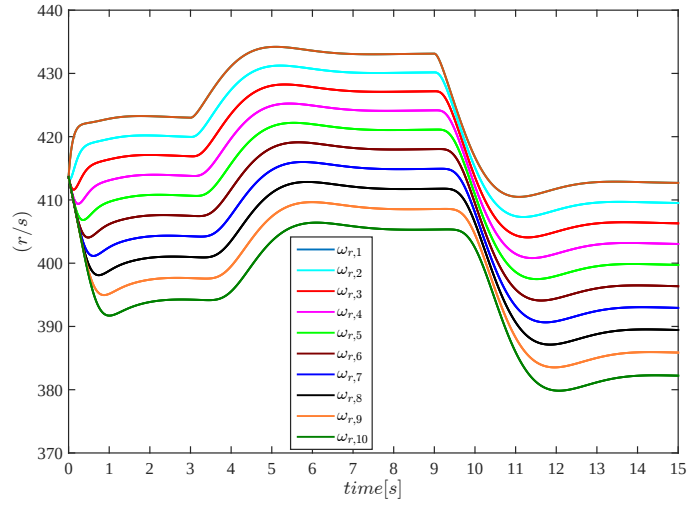
This change signifies that the WGs’ loading levels have to increase in order for the WGs to be able to generate the same power P_d but now with lower wind-speed, $v_w = 12$ (m/s) instead of $v_w = 13.17$ (m/s). The auxiliary state-variable of the leader is the first to move toward the new equilibrium. Concurrently and in synchrony with the leader, each of the followers exploit the peer-to-peer communication to regulate their loading levels to the loading levels of their respective neighbors. Ultimately, these actions cause all loading levels to converge to the new equilibrium ξ_{h0} as seen in Fig. 4.11a, leading to fair load-sharing among the WGs.



(a) Loading levels

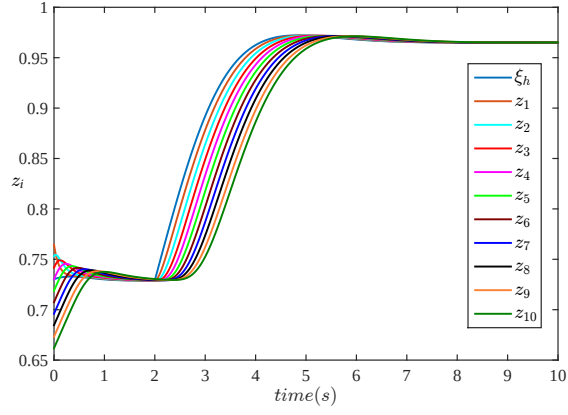


(b) Total mechanical power

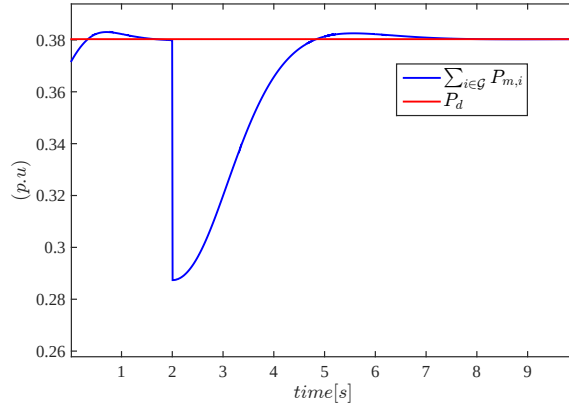


(c) Rotor speeds

Figure 4.10: Simulation results under *Scenario 1*

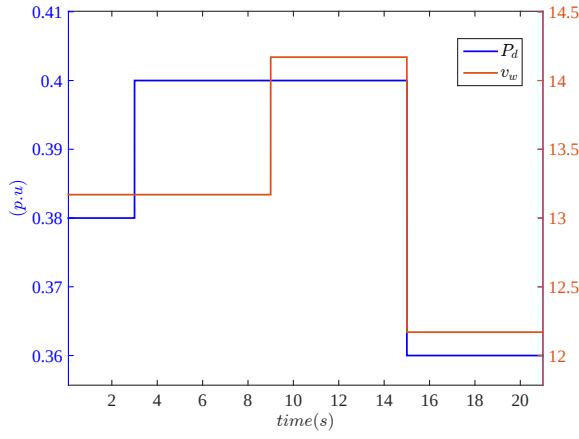


(a) Loading levels

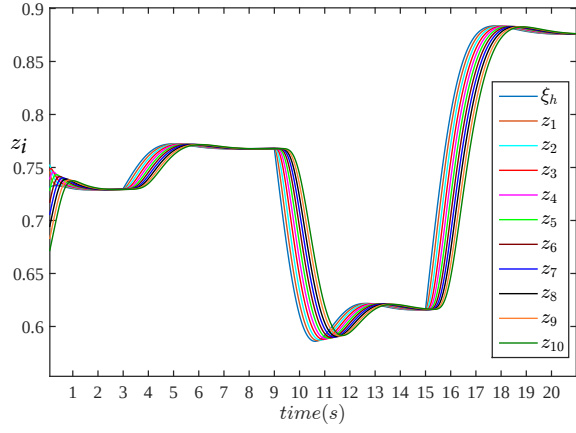


(b) Total mechanical power

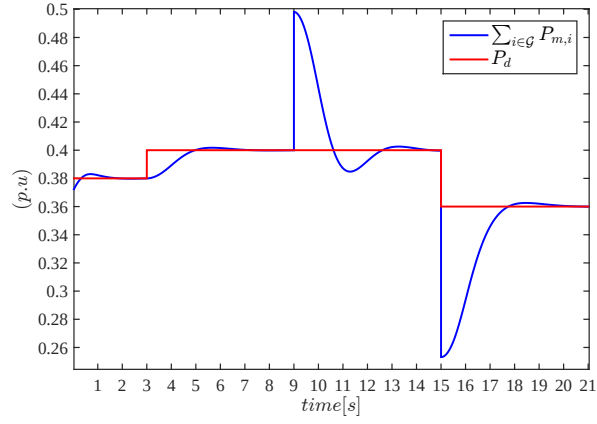
Figure 4.11: Simulation results under *Scenario 2*



(a) Wind speed (v_w) and power reference (P_d)



(b) Loading levels



(c) Total mechanical power

Figure 4.12: Simulation results under *Scenario 3*

In *Scenario 3*, the WF experiences both variations on the reference P_d and the wind speed v_w as can be seen in Fig. 4.12a. First, at $t = 3s$ the WF power reference increases from $0.38 p.u$ to $0.4 p.u$, causing both the loading levels of WGs, and correspondingly the total mechanical power, to increase, with the latter tracking the new value of the reference. These responses are depicted in Fig. 4.12b and Fig. 4.12c, respectively. At $t = 9s$, the wind speed increases from $13.17 m/s$ to $14.17 m/s$ (Fig. 4.12a). That leads the controllers to decrease the WGs' loading levels (Fig. 4.12b) such that they still generate total power equal to $0.4 p.u$ but now with higher wind speed. The abrupt rise of the wind speed causes a spike in the response of the total mechanical power, and at $t = 15s$, the sudden drop of the wind speed causes the mechanical power to dive as depicted in Fig. 4.12c. In the latter case, the loading levels increase in order to track their new equilibrium value that depends on both the reference P_d and the wind speed v_w . The reason is that the drop of P_d alone would cause the loading levels to decrease while the drop of the wind speed v_w alone, would cause the loading levels to increase. In our case, these variations combined eventually cause the loading levels to increase (Fig. 4.12b) which means that the effect of the wind speed variation is more pronounced on the new equilibrium of the loading levels.

In summary, the above numerical simulations verify that the proposed protocol and the corresponding distributed CLF-based torque controllers are able to distributively and dynamically self-organize and control a group of deloaded WGs in a fair load-sharing fashion so that WF power output regulation is attained under fast-varying conditions.

5. Discussion and conclusion

5.1 Open questions – future work

A big open question still remains in our work: how to appropriately integrate several PMUs in the developed control systems so the variables that are needed in the feedback control loop are readily available to the controllers. Given that, WFs can then better regulate their power output to given references and contribute to small-signal stability of large-scale systems under highly dynamical conditions. Our future work will focus on the practical implementation aspects of the developed wind farm control schemes with integrated PMUs.

5.2 Interactions with industry advisors

We interacted extensively with industry advisors and discussed the results and outcomes of our research in the annual PSERC Industry-University Members Meeting in 2015 and 2016. The questions raised by the industry people were mostly related to the practical applicability of the developed wind farm control methods and the corresponding technical requirements. We took the industry advisors' feedback into account and in the final journal papers that we published we also discussed how the proposed wind farm control methods can be applied in practice and the PMU-related requirements for the control methods.

5.3 Conclusions and proposed next steps

In summary, Part 2 of this report offers an extension of today's modeling in support of next generation SCADA first. This is needed to implement protocols for ensuring stable and reliable operation in the changing electric power industry which has become very complex as unconventional technologies and non-utility owned stakeholders connect to the power grid. It is proposed that today's Balancing Authorities (BAs) further evolve into end-to-end intelligent Balancing Authorities (iBAs). All end users connected to the electric power grid must belong to one of the iBAs and cooperate with the iBAs coordinators for communicating their needs and abilities to participate in power balancing and delivery. Similarly, all the iBAs must exchange minimal information to be coordinated by the utility system operators to ensure stable and reliable operation at value. The basic information exchange proposed is in terms of power, rate of change of power for each specific time horizon of interest. Similar to AGC requiring ACE information for quasi-static frequency regulation, iBAs must either communicate needs or provide specifications of power, rate of change of power and time horizon over which they are capable of meeting their commitments. The time horizons are a stratum of times ranging from milliseconds to hours. Once such specifications are set, all end users and IBAs will begin to consider their technological options for meeting these specifications and their value, if/when participating in markets for these services. The specific methods reported in Sections 3 and 4 now become options for consideration by the iBAs to meet their operating requirements. In Section 3 methods for placing the PMUs and controllers so that each iBA is observable and controllable so that it meets the specifications in terms of power, rate of change of power and time horizon over which the specifications can be met are implementable. In Section 4 specific examples of control for wind power farms and their coordination into an

iBA are introduced. The main recommendation to PSERC members is to consider the proposed extension of today's SCADA and its required information exchange for possible adoption. Prof. Marija Ilic is willing to volunteer her time to move this concept further. As the first step, she gave a PSERC seminar on September 26, 2018. Notably, this relatively low cost project has helped fund partially 15 publications and provide partial support for two doctoral theses at CMU. This support by PSERC is greatly appreciated.

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6. Appendix

FERC Reliability Technical Conference

Panel I: 2016 State of Reliability

Remarks of Marija Ilic, Professor
Carnegie Mellon University
June 1, 2016

It is my great privilege and honor to respond to specific questions raised by this panel. Thank you for this opportunity. The comments provided are strictly mine and do not represent positions taken by any other parties. However, they are result of many R&D years with my collaborators, and their direct or indirect input is greatly appreciated.

I first make several general comments, and then respond to specific questions raised by the Commission in light of these comments.

General comments

Need to relate mandatory standards with their quantifiable relevance to reliable and efficient BPS operation--Given a very complex nature of operating BPS, it is often difficult for non-utility industry participants to appreciate the need for mandatory standards of one kind or the other. Because they are viewed as additional cost to the basic electric energy services, it is necessary to have a way to directly interpret their relevance for reliable and efficient operation. We suggest that it is, therefore, necessary to work on evolving mandatory standards so that this becomes possible.

One way forward would be to establish general, relatively simple, framework based on common transparent and quantifiable metrics and protocols. The framework should be based on straightforward physical and economic principles. To achieve this, it is necessary to base today's standards on unifying principles of electric power system operations subject to end users' quality of service (QoS) specifications. This is a tall order, given that today's system operation is a complex mix of various methods under various assumptions.

For the basic framework to work (ensure reliable service at well-understood value to all) it must be designed to account for complex spatial and temporal interdependencies within a multi-layered multi-temporal architecture of the emerging electric energy systems. The complex multi-layered spatial boundaries create well-known "seams" problems; these problems are not only between Balancing Authorities (BAs), they exist within a BA between Transmission System Owners (TSOs), Distribution System Owners (DSOs); between utility-owned and non-utility-owned parts of the system. To overcome this problem, all components must provide information about their ability to contribute and their needs for reliable service using common interaction variables between themselves and the rest of the system. Second, in order to manage highly dynamic system reliably, a family of well-organized temporal standards is necessary. These needs are described next. We identify key open problems which require solutions. Finally, we take the liberty to propose possible solutions based on our long-term R&D findings.

Need for distributed, multi-layered standards-- Technological and organizational industry changes have led to BPS architecture with “nested” Balancing Authorities (BAs) [Ref. 1]. Each group of components responsible for participating in reliable service at value is called an intelligent Balancing Authority (iBA) [Ref. 2]. For example, non-utility-owned parts of the system with their own sub-objectives are often embedded inside today’s BAs and are hard to align with the utility objectives. To account for their effects, more granular standards for all BPS members must be established. Clear characterization of their roles in balancing the system during both normal and abnormal conditions is required. NERC reliability standards recognize this emerging architecture evolution, and have been geared toward setting mandatory rules for both utility-owned and non-utility-owned generators. These should be extended to all groups of components within BPS in accordance with well-defined principles.

Key open technical problem comes from lacking technical foundations for relating certain BPS operating problem (loss of synchronism, for example) to the mandatory requirements on specific equipment and its physical controllers (primary frequency reserve in the case of loss of synchronism); much serious industry effort is under way to solve this problem [Ref.3]. However, since it is fundamentally impossible to uniquely map a specific BPS reliability problem to the technical requirements which must be met by the components themselves, many such on-going industry efforts will still face the fundamental problem of how to justify the technical requirement set by the mandatory standard.

This problem can be overcome by requiring all components to provide information themselves about their ability to participate in reliable service, and the system operators to use this information to minimally coordinate them on-line so there is no system-level problem. Moreover, if components also provide the cost associated with their participation in reliable service, it also becomes possible for system operators to manage the system efficiently without deteriorating system-level reliability.

To do this systematically, without biasing certain technologies and participants, we propose that common variables and metrics must be used and that these must be replicable and quantifiable. Higher-level iBA entities must be responsible for meeting standards expressed in terms of the same types of variables and metrics. The key role of higher level iBA is to minimally coordinate its member iBAs so that their own metrics are met.

Need for dynamic, multi-temporal standards— The well-established approach to power balancing in the past has been “horizontal”, namely the slowest generators are scheduled first, and the faster ones are scheduled closer to real time to supply system-level demand. This has been possible because the system demand has been quite stationary and predictable. Feed-forward (ahead of time) scheduling of generation is done so that the only feedback (automation) needed is to regulate frequency in response to hard-to-predict imbalances in between scheduling intervals (AGC, by the BAs) and primary stabilization in response to fast small deviations in near real time (primary control, by the governors, AVRs and PSSs primary controllers of generators).

Key new challenge —These historically practiced temporal hierarchies underlying power balancing are currently challenged as both net load and new technologies connected to the system often exhibit previously unseen temporal fluctuations.

Proposed technical solution—In order to bring some order to balancing power over time by the most effective technologies, it is essential to think of standards as “dynamic” standards [Ref. 4,Ref. 5]. All components connected to BPS are responsible for providing specifications about their ability to participate in balancing power at certain rate and over certain time horizon. If this information is provided, it becomes then the responsibility of system operators to request the right amount of power at the right rate from technologically very diverse components. For technical details on such dynamic standards, see [Ref.4, Ref.5].

Possible Dynamic Monitoring and Decision Systems (DyMonDS) framework for Reliable, Efficient and Clean Electricity Service

The idea of having common metrics and protocols within a consistent general framework raises the key technical question regarding the existence and nature of such common variables and metrics.

To account for complex multi-layered BPS spatial architecture, we first must think of a BPS as comprising many electrically interconnected heterogeneous iBAs [Ref.1, Ref.2,Ref.6]. Each BPS member (component, or group of components, physically connected to the grid) must belong to an intelligent Balancing Authority (iBA).

To account for complex multi-temporal dynamics, the required information must be in terms of temporally-organized metrics relevant for the entire range of operating problems.

Definition of intelligent Balancing Authority (iBA) —A group of cooperative components within the BPS freely bundled according to its own objectives and subject to its own technical constraints. In order to be part of BPS it must: (a) provide information about its ability and needs in terms of variables and metrics common to all other iBAs; and, (b) must participate in protocols determined by the higher-level iBAs, ultimately responsible for reliable service at today’s BA levels and higher.

The proposed general framework is named Dynamic Monitoring and Decision Systems (DyMonDS) framework. It is based on straightforward on-line information exchange between iBAs according to a simple protocol that lower level iBAs must provide information to the higher level iBAs to which they are electrically connected. The higher-level iBAs, in turn, have the responsibility and authority to minimally coordinate their iBA members. Each iBA has its own “DyMonDS” defined as follows:

Definition of DyMonDS—Information processing unit responsible for providing information about its common metrics and QoS. The unit is equipped with sensors, automation, computer applications in support of their own decision making so that it is capable of meeting its own specifications. These are characterized in terms of common interaction variables (intV) and Quality of Service (QoS).

Definition of Common Interaction Variable (intV)--- An interaction variable $z_i(t,T)$ between component i and the rest of the system is characterized as a set of physical variables comprising incremental stored energy $E_i(t,T)$, power $p_i(t,T)$ and rate of change of power $dp/dt_i(t,T)$ which an iBA can produce or which it needs.

Definition of Common Metrics--- The general metric represents bounds on common variable intV.

Definition of Quality of Service (QoS)--- Each iBA specifies limits on voltage $\Delta v_i(t,T)$ and $\Delta f_i(t,T)$ frequency deviations acceptable.

Shown in Figure 1 is a sketch of DyMonDS-based SCADA. It can be seen that DyMonDS framework is basically next generation SCADA system required to implement protocols for on-line information exchange in support of reliable and efficient service at specified QoS. It can also be seen that multi-layered, multi-directional and multi-temporal information exchange becomes key to systematic operations and control.

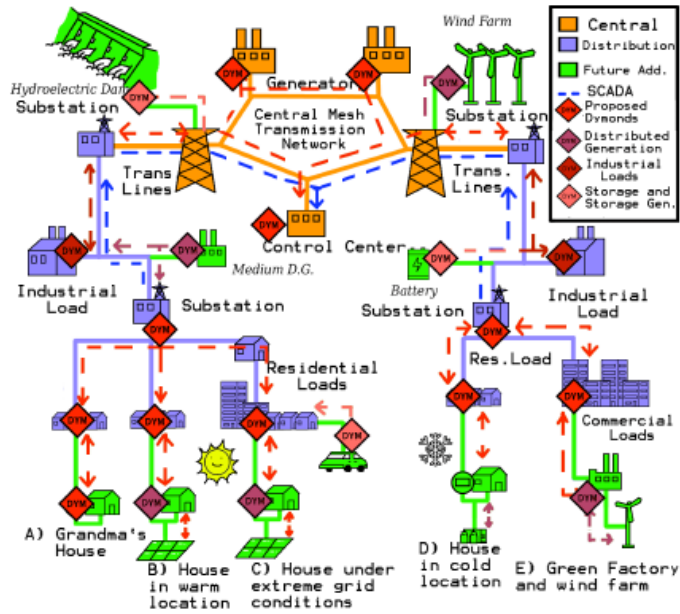


Figure 1 DyMonDS-based next generation SCADA [Ref.2, Ref.6]

Several important observations regarding proposed DyMonDS framework

Natural outgrowth of today's operations --- Proposed metrics and protocols underlying DyMonDS are direct extensions of well-known Area Control Error (ACE) used in Automatic Generation Control (AGC). The extensions are two-fold: An ACE-like interaction variable is introduced to characterize any given component connected to a BPS and intV must be defined over carefully-organized temporal horizons T so that all operating problems are managed using these variables [Ref. 6]. The basic technical idea is that the instantaneous power must balance at several rates and that users must have desired QoS. In AGC power balances

every 10 minutes by responding to ACE (incremental energy, average power over this period) and frequency at the BA level is specified QoS. Very similar extensions can be introduced for specific dynamic problems of concern to NERC. In our answers to specific questions we illustrate this under Part b.

Possible to interpret all NERC requirements in terms of common variables and metrics—This fact is critical. Recent CMU provisional patent [Ref. 6] offers unified modeling by transforming current dynamic modeling into multi-layered modeling. Original variables of any dynamic component can be represented in this new space as comprising its intV and the remaining internal states. It is shown that components must know their internal states to design their sensing and control so that they can operate within the specified metrics. On the other hand, higher-level inter-area dynamical model does not have to know internal technological details nor models. Higher-level iBA can minimally coordinate its interconnected components so that no reliability problems of any sort occur. This model is fundamentally critical for moving forward in this vastly multi-layered industry.

No requirement on one size fits all -- Reliability problems of concern to engineers can be managed by the smallest iBAs themselves, or by the higher-level iBAs. How is this done depends on the available control at different level iBAs, as well as on their interest to explore new solutions. Even the boundaries of iBAs can be created in a bottom up way as long as each iBA follows the proposed protocol.

Implications of using DyMonDS framework on innovation

Explicit incentives to select right technology—Assuming a general framework as proposed, it becomes possible to innovate at well-understood value to those doing it. The BPS members have clear options between implementing technologies to meet the metrics/standards themselves, or in cooperation with other iBA members. Higher level iBA can coordinate its members by either allocating technical responsibilities or by having market incentives in an IT-enabled DyMonDS environment. A quantifiable binding burden of proof is set on all BPS members to meet their metrics measured in terms of interaction variables or pay to iBA for doing it on their behalf. The incentives shift to the level of granularity needed to assess what may be the most effective technology (software and hardware) to which BPS members. In particular, iBAs quickly recognize that for them to meet their metrics it is essential to operate in a much more flexible way than it is currently done. We point out that for this to be implemented much innovation is needed in software for enabling on-line reliable operation. Instead of ERO mandating provision of, say, specific primary frequency reserve, or voltage control, or deployment of FACTS, iBAs will utilize these so that their performance metrics are met in the most effective ways.

Recommended software innovations— For DyMonDS framework to become reality, it is necessary to enhance both automation embedded into components/iBAs and computer applications currently used by the system operators. Decisions on how to operate BPS on-line as conditions vary are currently based on system operators' knowledge about the specifics of their part of the system and on the off-line analyses under different assumptions. In particular, today system operators base their decisions on the worst-case contingency

studies. We recommend that NERC and Commission would do well to move toward corrective reliability management with minimal required reserve for non-time critical contingencies. This means that, instead of operating during normal operations conservatively so that in case contingency happens no system-level problems occur, it is necessary to have software which, after a contingency occurs, quickly decides on what are the best adjustments on the remaining functional equipment. This mode of operation is likely to become unavoidable because of higher presence of hard-to-predict worst-case scenarios created by larger variations in net demand as seen by the BPS operators. In our Part b. response we illustrate potential value of an extended AC OPF, for example, when determining rule on reactive power support.

Also, to avoid time-critical problems, it is essential to ensure that iBAs have sufficient embedded automation to transiently stabilize equipment in response to large sudden changes, including faults. Humans can only act at limited speed. Theoretical state of the art designs are known for designing nonlinear controllers of several types so that closed-loop primary dynamics are stable within the specified bounds on interaction variable (metrics). Manufacturers need to implement such controllers. Otherwise, the system will experience previously unseen oscillations such as sub-synchronous control instabilities (SSCI) [Ref. 7,Ref.8]. NERC should require testing of equipment automation prior to deploying to the system so that the dynamic standards are met as measured in terms of metrics set on interaction variables.

Minimal information exchange and internal privacy- Relevant for availability requirement of certain databases, the model used by an iBA to ensure that the specified metrics are feasible by means of their own primary control design is a very detailed model of specific technologies. The higher-level model is only in terms of interaction variables of all iBAs within the BPS; it is, therefore, sufficient to coordinate actual power outputs for stabilizing system-level performance without knowing full detail of internal models and parameters. The bounds on interaction variables (metrics) can vary in operations, the higher level iBA simply selects the actual value of the interaction variable for all of its iBA members so that no system-wide operating problems occur. For reliable service to be implemented at the BPS level, it is necessary to only exchange information about interaction variables between the iBAs and their higher level iBA. It is not essential for the highest BPS level operating entity to know much detail about the specifics of technologies embedded within the lower-level iBAs. This observation sets the basis for a new multi-layered approach to ensuring reliability by:

- Requiring non-uniform specifications of all iBAs in terms of their own interaction variables; these variables are common to all iBAs. Achievable bounds on interaction variables (metrics) must be guaranteed and tested by the iBA itself at each rate of response of interest. This requires full knowledge of local iBA only.
- Requiring higher-level iBAs to minimally coordinate the actual values of interaction variables so that bounds on interaction variable at their level are also met. This does not require full knowledge of local iBAs comprising the higher-level iBA. Only bounds on their interaction variables are needed.

Much the same way as AGC of each BA (formerly control area) is characterized in terms of its own Area Control Error (ACE), each iBA is characterized in terms of its own interaction

variable with the rest of the system; and has much autonomy to decide on technologies and means of meeting the AGC standard.

Potential effects on economics for reliable service- We suggest that DyMonDS framework gives lots of flexibility to save while observing reliability. Members within each iBA are free to decide on how to implement their specified metrics and to cooperate to make the most out of their resources. Savings within any given iBA happen through cooperation. Savings across same-level iBAs are achieved either through minimal coordination or through competition depending on the tradeoffs of potential gains and complexity of communications implementation. Notably, iBAs compete within the BPS for their members. A well-designed electricity market is ultimately DyMonDS framework in which technical and economic signals are communicated and aligned [Ref. 9]. For this to happen, common IntV and metrics must also have the cost specified.

In closing-- We humbly suggest to the Commission and NERC to further consider the proposed DyMonDS framework. It is not too late to re-think principles of mandatory standards for reliability and establish a general framework according to such principles. Such an approach is likely to make the overall process systematic and easy to quantify and monitor. We have developed at CMU a Smart Grid in a Room Simulator (SGRS) in collaboration with NIST which can be used as a means of demonstrating DyMonDS-enabled BPS performance and for comparing it with the effects of today's mandated standards [Ref. 10]. We point out that the proposed framework is not suggested lightly; we have simulated many of its aspects using real-world models of electric grids in two Azores Islands. This work started in response to the challenging question of how would one minimize the use of expensive fossil fuel without increasing long-term electricity service cost and without affecting QoS [Ref. 11]. I strongly believe that we could extend these concepts to enable BPS reliable operations at reasonable long-term cost.

Response to Specific Questions Raised by the Commission Panel 1

a. Primary accomplishments and new future issues

Planners, operators and transmission owners have continued to work hard to ensure no major loss of service at the BPS levels. They are to be congratulated for this. As pointed out by all participating in this panel, the system has performed well; this has been mainly accomplished by a heavy reliance on a combination of mandatory standards for reliability and the engineering expert knowledge. However, the industry has remained short of having a unifying framework in support of systematic transitioning from voluntary to mandatory standards; as a result the process has been extremely time consuming and hard to follow. Perhaps the main challenge has been the lack of simple transparent metrics and protocols underlying evolution of standards. In our General Comments we provide a detailed discussion of this issue and propose a possible framework for moving forward. Our basic recommendation is that a systematic approach to innovating today's engineering tools and computer applications should be given major attention when defining reliability standards in such complex systems. It is well-known that the complexities are not only technical, but economic, organizational and societal. Aligning all of this requires systematic framework.

Furthermore, ensuring reliable service by strictly planning more equipment (transmission, generation) and not changing the way the infrastructure is used in the actual operations will fall short of ensuring reliable service at any reasonable cost as uncertainties seen by the BPS operators increase. In particular, relying on off-line analyses and putting the burden of proof on operators to make on-line decisions will result in many situations previously unseen by them and in hard-to-foresee wide-spread blackouts. We strongly recommend that Commission and NERC consider enhanced decision-making tools beyond the ones currently used. Improvements are needed to facilitate on-line decisions by system operators; computer applications capable of managing events on-line as they occur, instead of relying solely on the worst-case reserves are critical. Similarly, fast automation capable of avoiding time critical events (fast control and protection) must be deployed; humans can only act at certain speed.

b. Assessment of the effectiveness of NERC's reliability activities and related industry efforts

The Commission and NERC have issued several dockets related to reliability services. They all share common challenges described in my General Comments. In particular, various activities have been concerned with various specific technical requirements and have not addressed these requirements in direct relation to their impact on reliable system operations. We have seen a sequence of dockets which are hard to interpret by those who are not intimately familiar with the power system operations. This situation begs questions regarding the need for these services and the amounts mandated. As explained in our General Comments above, this is simply because at present the industry does not have general model-based framework which in a transparent way explains how the BPS operates and why are certain standards needed.

The proposed Dynamic Monitoring and Decision Systems (DyMonDS) framework offers a relatively straightforward thinking about how is very complex BPS operated. It is as simple as having to balance power (deliver produced power to the locations needed) at the fast rate. The faster the rate at which the power balances, the less deviations in system frequency and voltages. So, the natural common variables for defining metrics are in terms of integrals of power (incremental energy), power and rate of change of power. Everyone can understand this. Moreover, the Quality of Service (QoS) is courtesy to the BPS end users, and should not be explicit in determining system-level requirements. It is these two observations, together with lots of theoretical foundations work, which should begin to set the basis for common metrics and protocols. Once this is understood, one begins to avoid all together difficult details regarding exact protection standard settings, or specifications for frequency reserves (primary and secondary) and voltage/reactive power support complications. These should be internal to those operating the system on-line as information about common metrics is made available and updated on line. It is no longer possible to operate the system reliably for the worst-case scenario which is probably never to happen. What is needed are methods for resilient on-line operation.

To illustrate, we briefly discuss some recent activities by the Commission in light of our general comments:

The debate regarding essential reliability services --the first Docket No. RM16-1, November 2015 about exemption for wind generators from providing reactive power--- It does not appear plausible to provide meaningful incentives for this support without having interactive protocols in place to select out of many different options the ones which are most effective as seen by the higher level iBAs. For example, given metrics, AC OPF obtains the most effective reactive power support [Ref.12]. As a rule, the result of AC OPF based voltage dispatch is never for all iBAs to provide the same reactive power support. The question of reactive power support is particularly thorny one for several reasons. To start with, based on the discussion in general comments, no common metrics are needed in terms of reactive power. Instead, only QoS measured in terms of acceptable voltage deviations explicitly enter the proposed protocol. Also, a closer look into controllers for generators and other equipment (including power converters) shows that none of these control directly reactive power, they control voltage. Therefore, it is needed that BPS members provide information on common metric specifications as well as ranges of acceptable voltage deviations and not worry about reactive power support specifications. Some of the BPS members would require higher level voltage dispatch coordination if they are not capable of supporting their own voltage, and other iBAs will be capable and willing to adjust their voltages within relatively large ranges, and, therefore, help out other parts of the system.

We stress that requiring each iBA to provide unity power factor is pointless for variety of reasons as we have documented in the past studies for industry [Ref.13]. Instead, much the same way as with other on-line corrective actions, as conditions vary the available resources are adjusted by the coordinating entities to ensure that a BPS as a whole does not experience voltage “collapse” problems. We have documented in excruciating details how this can be done for the case of NYCA [Ref. 13]. It was shown, for example, that on a hot summer day approximately 1GW power can be delivered beyond what is being delivered from Niagara to NYC by implementing voltage dispatch [Ref. 14]. Similar studies have shown that in PJM even after retiring major power plants the system can be operated reliably if on-line systematic voltage dispatch is practiced when dispatching real power [Ref. 15]. The infamous PV curve can become much more forgiving (allow for larger transfers) when voltage dispatch is implemented, as shown for the case of ERCOT [Ref.16].

Unfortunately, my discussions over the past decade with many leading engineers have clearly demonstrated that deployment of any new software creates a risk in its own right and, moreover, no direct incentives exist to do so. As a result, sub-optimal utilization of available resources takes place and, at the same time, the threat of voltage collapse is not eliminated; at least a dozen major blackouts worldwide have been caused by poor management of available reactive power resources, and not by their shortage. It was shown that the blackout of 2003 could have easily been avoided by on-line corrective actions despite the specific triggering event [Ref.17].

However, if there are no bids in terms of financial incentives this is hard to do since higher level iBAs won't have a quantifiable way of allocating cost of meeting reliability performance by diverse smaller iBAs. Of particular importance are incentives to lower level iBAs and transmission and distribution owners to help support voltage by their higher level iBAs. Adjusting tap changer setting and AVR settings in NYCA BPS (and/or) the neighboring systems would be a major means of directing more power from clean hydro to NYC. Serious economic studies must be done to compare the effects and cost of such BPS solutions (dominated by economies of scale) to the solutions envisioned by NY REV (deployment of many small-scale DERs).

Provision and Compensation of Primary Frequency Response, Docket No. RM16-6, February 2016 is particularly straightforward to discuss in light of our proposed reliability metrics. To start with, we highlight that frequency deviation is a rather poor indicator of power imbalance-related instabilities. Recall that even in steady state AGC is in response to power imbalance known as ACE, and not in

response to frequency deviation. Long ago adjusting frequency bias was a major job for at least one engineer. A single frequency bias in iBAs comprising highly heterogeneous technologies (with large and smaller, or no, inertia) is a non-starter and therefore an impossible job for designers of mandatory standards. Instead, we propose to specify metrics in terms of feasible ranges of power and rates of change of power. Determining the amount of primary frequency response can only be done if protocol is in place to specify which components are likely to cause how much sudden power change (either because they fail to operate or they have insufficient means of responding fast to follow desired rate of power changes).

Finally, selecting sources of primary frequency control should be revisited in somewhat serious way. It is our understanding that current industry effort is putting all its thinking into determining the bandwidth of governor response needed to have adequate primary frequency response [Ref. 3]. We stress that governor would quickly break if it were to serve the purpose of saving a generator from loss of synchronism following sudden rate of change of power output and being required to respond to it. Instead, AVR, PSS, SVC, FACTS, fast storage, such as flywheels and batteries (as the last resource because of their excessive cost) can all contribute in major ways to transiently stabilizing BPS response and preventing loss of synchronism. For this to be implemented, these potential suppliers of primary frequency response should make their metric known to the higher level iBA, which, in turn would assess which disturbances can the system withstand. Instead of reducing power transfers and making ranges of operating conditions more conservative prior to these disturbances, the higher level iBAs should solicit sufficient supply for stabilization across all these newly emerging technologies. While they may appear too costly to implement, it is possible to assess an optimal level of investment in fast power-electronically switched controllers whose cost pays off by operating the system efficiently during normal operations [Ref. 18]. It is at this critical time scale that PMU-based monitoring and wide-area control schemes may become essential, this is to be determined by the higher-levels iBAs. We stress that there exists fundamental difference between special protection schemes (SPS) on one side, and wide-area fast control schemes. The objective of protection is to disconnect the equipment, and the objective of fast control is to support the system operation even when protection would have had to disconnect it otherwise. A recommended case study is to take the case of SSR controller proposed in [Ref. 19] and compare to SPS in AEP for protecting the system against SSR [Ref. 20].

As a side note, principles for secondary frequency reserve are straightforward to determine, following the same general metrics. As an illustration of possible standards for ensuring small signal stable frequency response and frequency regulation within the pre-specified threshold is just an example of the more general principle proposed [Ref. 21].

In short, we strongly recommend taking a step back and setting up systematic principles for primary frequency support protocols according to the general proposed metrics, instead of struggling with tightening up the requirement for governor response.

Please notice that sufficient flexibility ought to be given to both existing and new resources when attempting to implement consistent protocols and standards. The response given to me during a recent presentation at CA-ISO is very supportive of the proposed metrics and protocols [Ref. 22]. Two basic takeaways from that meeting are: Both engineers and market folks understand power, rate of change of power, and incremental stored energy. Our findings so far are that it is sufficient to have multi-temporal metrics in terms of these variables only without being too concerned about the type of technology and its details.

All the other Commission events (Ride-Through Requirements for Small Generators, Docket No. RM16-8, March 2016; NERC Reliability Standard for Geomagnetic Disturbances, TPL-007-1; FERC Docket No. RM15-11, May 2015; FERC proposed directive for new requirements Docket No. RM15-14, July 2015)

should be assessed in light of common general framework for reliable services proposed here.

FERC proposed non-public access for Commission staff
Docket No. RM15-25, September 2015

Relevant for availability requirements of certain databases, the model used by an iBA to ensure that the bounds on interaction variable are feasible by means of their own primary control design is a very detailed model of specific technologies. The higher-level model is only in terms of interaction variables of all iBAs within the BPS; it is, therefore, sufficient to coordinate actual power outputs for stabilizing system-level performance without knowing full detail of internal models and parameters. The bounds on interaction variables can vary in operations, the higher level iBA simply selects the actual value of the interaction variable for all of its iBA members so that no system-wide operating problems occur. For reliable service to be implemented at the BPS level, it is necessary to only exchange information about interaction variables between the iBAs and their higher level iBA. It is not essential for the highest BPS level operating entity to know much detail about the specifics of technologies embedded within the lower-level iBAs. This observation sets the basis for a qualitatively different multi-layered approach to ensuring reliability by:

- Requiring non-uniform specifications of all iBAs in terms of their own interaction variables; these variables are common to all iBAs. Achievable bounds on interaction variables (metrics) must be guaranteed and tested by the iBA itself at each rate of response of interest. This requires full knowledge of local iBA only.
- Requiring higher-level iBAs to minimally coordinate the actual values of interaction variables so that bounds on interaction variable at their level are also met. This does not require full knowledge of local iBAs comprising the higher-level iBA. Only bounds on their interaction variables are needed.

c. What metrics have been, or should be, developed to define whether reliability, in whole or in part, is improving? How can we assess if the risk of blackouts is increasing or decreasing and, if increasing, due to what causes? Can a quantitative risk analysis be used?

Reliability is not a single number! It should be measured in terms of how are specified metrics and QoS met by BPS members and by the higher-level iBAs. If BPS members specify their common metrics (bounds on stored energy, power and rate of power change) they are capable of providing or needing, as well as their own QoS acceptable, it is up to higher-level iBAs to implement these according to their least cost metric (a combination of fuel cost, environmental impact and risk of not serving); here, again, iBAs metrics are measured using the same variables as for their members. A quantitative risk analyses depends on how is the system operated, and the effects of operating practices should be looked into very carefully. Proactive protocols should be put in place to enable implementation of desired reliable service within the multi-layered BPS.

Coordinating protocol for ensuring reliable service becomes the one of computing the actual value within the ranges specified by the metrics of BPS members and sending the commands to them to implement at different rates relevant for specific technical problems. Dynamic standards are fundamentally families of multi-temporal requirements as follows:

To avoid sub-synchronous electromagnetic and electromechanical oscillations –each iBA must specify range of power needing/producing at the rate relevant for this dynamic phenomenon, say specifications must be set for response within the split second time intervals[Ref. 23].

To avoid loss of synchronism --each iBA must specify range of power needing/producing at the rate relevant for this phenomenon. These are typically rates relevant for ensuring critical clearing time following major loss or major sudden dip in power generated or consumed [Ref. 24]. For example, an iBA could be a wind power with storage and conventional generator jointly managing loss of synchronism when a fault occurs in their part of the grid [Ref. 25].

To avoid small signal instabilities specifications of the proposed metric must be made for the time responses so that they do not trigger under-/over-frequency and voltage [Ref. 26].

To ensure frequency and voltage regulation the existing ACE metric must be specified for minutes to 10 minutes [Ref. 4,Ref.5]; in systems with continuously fluctuating DERs the existing ACE must be enhanced and it becomes a dynamic metric [Ref. 26].

To ensure that ramping rates important for balancing power when dispatch is performed it is important to specify the proposed metric for time intervals over which dispatch is being done [Ref. 27].

The more granular metrics over time, the smoother system-level response is achievable. Adding to currently observed time scales the new shortest time scale which brings about the assurance that no power electronics-related electromagnetic instabilities would be created in response to extremely sudden changes, could be an excellent starting point for ensuring reliable service at value by all entities.

Specific recommendations for transparent regulatory rules in support of effective reliability standards

When/if iBAs fail to meet their specifications by not responding to the coordinating entities the reasons may be multiple. They could range from having failures in their own hardware components and/or failures in their embedded DyMonDS implementation. Part of the protocol is that they must notify higher level coordinating iBA and this entity should have stand-by ready methods to modify the commands to the remaining iBAs according to the well defined performance objective at the aggregate level. Similar interactive protocol must exist between all layers.

Monitoring whether the metric are implemented becomes the objective of enforcing reliability standards. An important technical detail is that if all (groups of) component(s) are required to participate in enabling reliability than one could consider enriching the protocols to specify two types of metrics: The first metric is to operate according to the best possible specified metrics, and the second metric is to be specified for abnormal conditions when some components fail to meet the specified metric for normal operation.

We observe that the specifications of iBAs multi-temporal metrics must be made prior to the iBA connecting to a BPS. The on-line commands, on the other hand, are issued in a

feed-forward way at the rate determined by the higher level iBAs. The committed/required metric is implemented by the lower level iBA.

We point out that the technical problem of higher level iBA coordination so that the system as a whole does not experience instability problems at particular rate and to also ensure that system frequency and voltage remain within pre-specified bounds requires serious attention by both industry and academia. It is truly a solvable problem. As an example of control area computing how much power (secondary frequency reserve) and at which rate so that the system frequency settles to within the pre-specified threshold epsilon can be found in [Ref. 21]. It is extremely important to observe that this is not possible to answer unless all BPS members and iBAs specify their demand for frequency reserve to compensate likely deviations from dispatched power and all iBAs providing frequency reserve specify their ability to do so in terms of above proposed metrics. Similar extension is needed to all metrics within the multi-temporal family for each iBA, independent from the specific technology or ownership.

Specific recommendations for transparent electricity market designs in support of reliability service at value

Parts of the large complex bulk electric power systems which are operated as electricity markets naturally lend themselves to participating in reliable service at value by being required to specify the same technical metric. In addition to specifying the technical metric they would be required to participate in a family of multi-temporally clearing markets by providing supply and demand bid curves for $[E_i(t,T)^{\min}; E_i(t,T)^{\max}]$; range of power $[p_i(t,T)^{\min}; p_i(t,T)^{\max}]$ and rate of change of power $[dp_i(t,T)/dt^{\min}; dp_i(t,T)/dt^{\max}]$ capable of either producing or needing during the time T of interest. The role of higher level iBAs then becomes the one of not only ensuring that the technical metric is implemented according to their coordinating commands, but also that the cost of ensuring reliability is optimized. For transactive energy control to work such specifications will become essential.

Specific recommendations for combining technical standards and market design rules

Notably, the proposed reliability metrics are expressed in terms of common variables $[E_i(t,T)^{\min}; E_i(t,T)^{\max}]$; range of power $[p_i(t,T)^{\min}; p_i(t,T)^{\max}]$ and rate of change of power $[dp_i(t,T)/dt^{\min}; dp_i(t,T)/dt^{\max}]$ capable of either producing or needing during the time T of interest for both reliability and for defining market derivatives hybrid solutions are possible. Given this important fact, hybrid solutions are possible in which existing iBAs may meet technical standards while the newly deployed technologies can be selected by the electricity markets to best align the cost and technical performance.

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