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Distributed Control With Local and Wide-Area Measurements for Mitigation of Cascading Outages

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Abstract—Modern electric power systems are extremely reliable but occasionally suffer from cascading failures initiated by localized asset removal. As lines and transformers overload and are taken out of service by protective relays, the system can progressively weaken. Network interconnections then enable regional instability to expand into a wide area. Protective relays have unique information about initial outage causes and local behavior. This includes identifying whether the actions of the protective relays are related to fault conditions or overloads. Meanwhile, synchrophasor technology now provides wide-area information in real time. The combination of local and wide-area information that is time-synchronized provides the ability to stabilize electric power systems in ways that minimize necessary control actions. This paper describes the development of a control system that applies local information in coordination with synchrophasor measurements to assess the complete state of the power system and differentiate a local phenomenon from the possibility of an overload-related cascade. The system executes a set of actions to contain and minimize the event. This paper verifies the efficacy of the proposed control system algorithms against cascading line outage scenarios applied to an IEEE standard test system.

Keywords—wide-area control, synchrophasors, cascading outage, phasor measurement unit, protective relay, intelligent electronic device, system integrity protection scheme

I. INTRODUCTION

Digital protective relays perform exceptionally well at isolating faulted lines [1]. They also take detailed, high sample rate measurements of power system signals at the local level. In certain situations, excessive system loads can produce similar characteristics as that of a distant fault and therefore trigger the protection element [2]. Typically, removing an overloaded asset is beneficial because it avoids any potential equipment damage. However, transient overloads can arise when the system is heavily burdened. Removing a transmission asset decreases the network capacity, shifting the already heavy load to other assets that can then suffer the same fate, leading to a cascading outage [3] [4]. Adding a layer of control with the protective relays can help alleviate similar conditions, such as those caused by excessively low voltages, through the impedance-based identification of certain states [5].

Phasor measurement units (PMUs) are a new method of providing wide-area information in electrical transmission networks, sending streaming synchrophasor information to

control room displays and data archives. Phasor measurement capability is already available in digital relays installed in substations across the world.

In this paper, a distributed controller is described that applies the wide-area view of synchrophasors along with the localized view of protective relays. The synchrophasor data provide an overall representation of the power system state at the moderate sample rate of once per cycle. The relays provide a detailed view of the local conditions at high rates of multiple samples per cycle. This dual set of information forms the basis for the design of distributed control with local and wide-area inputs. Because of the significant processing power available in a protective relay today, the relay takes on the additional role of local controller. The system aids in stopping cascading outages before they progress past a regional area. The control system is designed for distributed deployment to improve reliability. It operates in an iterative feedback manner in order to continuously adapt to changing conditions.

II. THEORY OF OPERATION

A. General Operating Principles

For power systems in the United States, the North American Electric Reliability Corporation (NERC) regulations define several operating cases [6]. Under normal operating conditions, the goal is to maintain system stability and signal limits while optimizing the transmission of electric power at minimum cost. With the loss of a single asset (identified in this paper as the alert case), the system must remain stable, but load shedding is not an option. For the loss of multiple assets (identified in this paper as the emergency case), the goals of optimum cost and transmission efficiency are temporarily set aside in order to focus on system stability. More severe controls, such as the redispatch of generation or load shedding, become available in accordance with the applicable regulation. The control system described in this paper is for operation during these emergency conditions.

A block diagram of the developed control system is shown in Fig. 1. Each distributed controller receives synchrophasor information covering a wide area. From the synchrophasor measurements, existing power flows and injections are calculated by each distributed controller. The distributed controllers also receive the margin to line overload from the local controllers. This margin is based on measurements and

conditions that are contributing toward any pending asset removal operation.

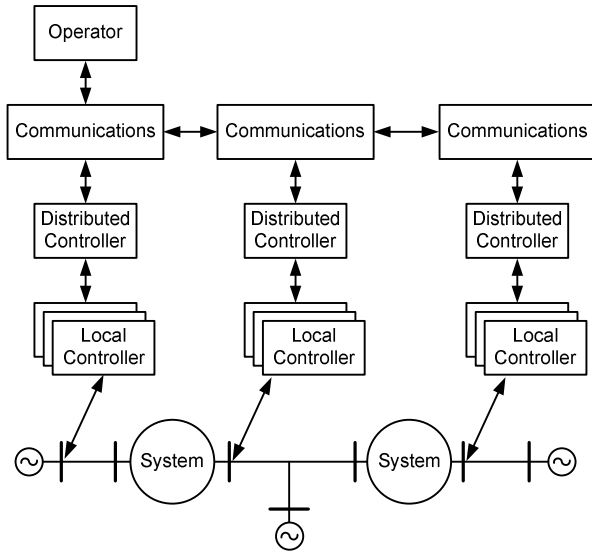


Fig. 1. Distributed control system with local and wide-area inputs.

The combination of local and wide-area control with real-time network information allows the distributed controllers to predict and analyze contingencies. These predictions mean that the distributed controllers can preemptively take action to prevent a local initiating event from resulting in a cascade. Alternatively, if the event in question is estimated to not lead to customer interruption or network instability, the distributed controllers step aside to let local controllers operate as normal. In this case, the distributed controllers adjust local relay set points to let the network adapt and ride through a transient without initiating sympathetic trips.

The communications network between distributed controllers is similar in topology to the electrical network. Thus, communications between distributed controllers that are electrically close on the transmission network tend to be highly reliable. Communications with more distant distributed controllers may be less reliable, but communications are also less necessary for effective operation because the controllers are more electrically distant.

B. Operations at Local Controller

During an actual fault, the impacted line is opened and can potentially reclose if conditions allow. In the absence of a fault, some conditions may appear as a fault to the relay algorithms but in fact be symptoms of overloaded conditions. Using the capability of modern digital protective relays, it is possible in many cases to distinguish between true fault conditions and overloads [7].

The basic idea is to track the measured impedance rate of change. Impedance trajectory tracking has already been implemented in some digital protective relays in the form of power swing blocking logic. This logic operates on the principle that the rate of impedance change is an effective way of differentiating between a power swing and a fault. While this algorithm is typically sufficient to differentiate between

these conditions, additional analysis is required to differentiate between faults and overloads.

Fig. 2 shows a mho circle characteristic with impedance trajectories for two different events. Trajectory A is indicative of a fault where the impedance seen from the local controller rapidly moves in a direct path from normal to a point near the line impedance locus. Trajectory B is indicative of an overload where the trajectory gradually moves toward the trip region via a circuitous path. The relay can differentiate the types of events by analyzing the rate of approach toward the line impedance locus, the variation of direction, and the incremental change. This method of differentiating overloads from faults is not perfect. The control algorithm described in this paper takes advantage of such differentiation when it is possible. When a decision between the two cases is not possible, then the control algorithm disables, defaulting the system to its original operation.

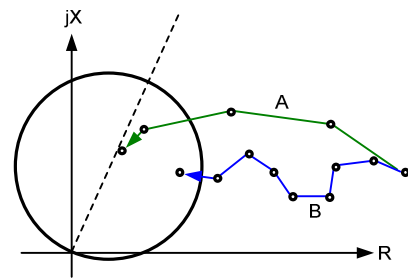


Fig. 2. Impedance plane trajectory for two cases.

Additionally, if a local controller is informed of a pending overload-related trip in its local vicinity, a set-point modification is directed by the associated distributed controller. This allows the relay element in the local controller to more effectively ride through the transient without triggering unnecessary asset removal. One potential set-point change can enable blocking logic, as previously described, to prevent inadvertent operation of a distance element due to the power swing.

C. Operations at Distributed Controller

The distributed controller monitors various local controllers under its supervision, coordinates with other nearby distributed controllers, and directs actions and set-point modifications. The distributed controller is also continuously receiving and processing synchrophasor information to provide a real-time picture of the network condition. The coordination between distributed controllers includes the following three parts:

- Publishing network stress information, such as a line loading nearing its limit, and pending trip information from local controllers to other distributed controllers.
- Querying other distributed controllers about available control actions based on the present network situation and the effect of the actions on critical loads and assets.
- Commanding control actions and requesting information about the pending control actions of local controllers in coordination with the other distributed controllers.

The distributed controllers maintain an up-to-date model of the network by continuously collecting synchrophasor data and sharing network state information with other distributed controllers. Real-time synchrophasor measurements provide an accurate network state measurement from which various parameters of interest can be calculated, such as line currents, power flows, power injections, and flow sensitivities. These flow sensitivities are important because they are used to determine which control actions to execute to alleviate the necessary overload conditions.

When a distributed controller is informed of an overload-induced impending trip by one of its relay elements in a local controller, the distributed controller initiates a system of queries. It starts with itself and its associated local controllers and then queries other nearby distributed controllers, which subsequently query their associated local controllers.

This system of queries accomplishes two primary tasks. First, an evaluation of the state of the network is needed. It must be determined if the network is in its normal state or whether other transmission assets have been removed from service. This is important for determining what control actions are permissible per the applicable regulations and the severity of the transient initiated by the removal of any asset. If an overload is determined to be part of a cascade, then more aggressive or expensive control actions are available. A pending trip in the alert condition may only warrant an action such as reactive power insertion, whereas in the emergency condition, load shedding may be warranted. This query information is also used to notify operators about the present situation and pending control actions.

The second task is the creation of available control actions. When queried by a distributed controller, the local controller returns a list of available actions, such as load shedding, load tap changing (LTC) transformer blocking, or reactive power compensation. The distributed controllers then filter this information to remove control actions that do not contribute to relieving the overload condition and forward this subset to the initiating distributed controller. The initiating distributed controller evaluates this list of actions to determine the best action, if any, to take for the present situation.

If action is warranted and multiple overload conditions are present, the distributed controllers analyze which overload to address. The evaluation takes several forms because various issues affect this decision. The overload that causes a trip first is given precedence, along with overloads that have the highest fraction of excess flow as compared with thermal or stability limits. If a line is in overload and another line that is fed by this overloaded line is also in overload, the downstream line is given precedence because reducing the load on the downstream line also relieves loading on the upstream line.

III. SELECTION OF CONTROL ACTION

In some situations, there is no control action available that relieves the overload. The control actions can be limited by the availability of local controllers, regulations based on the operating condition, conditions outside the utility network, or communications problems. In that case, a distributed controller publishes the pending trip information to the rest of the devices

in the control system so that they can prepare further control actions.

Preparations take several forms. One is a temporary relaxation of relay element set points in a local controller to allow for riding through any transients initiated by the predicted trip and to avoid excessive tripping operation. The distributed controller communicates to operators (as shown in Fig. 1) to inform them of the asset removal and to suggest potential actions. The distributed controller also calculates overloads resulting from the impending trip and precalculates control actions for future selection to prevent a cascade. Finally, any islanding conditions caused by the asset removal are also anticipated and redispatched to ensure proper load-generation match in the respective islands.

Once the decision is made about which overload to relieve, the distributed controllers begin the process of determining the best action to execute. In general, it is desirable to use the minimum or least expensive action to relieve the overload. Because the overload is based on line flows but the majority of the control actions involve changes to bus injections, a way of translating the injections into flows is needed. A method for steady-state load flow analysis provides a framework to resolve this need.

Load flow analysis is a technique to determine the network state and associated variables of interest given a specified list of planned bus injections and constraints. Using these constraints and a model of the network topology and parameters, a Newton-Raphson power flow (see [8]) optimization is performed at each distributed controller to determine the set of voltage magnitudes and angles at all of the buses. This information set is the network state.

A sensitivity matrix relating the real (P_I) and reactive (Q_I) power injections at all of the buses to the voltage angle (θ) and magnitude (V) at those same buses is computed. The matrix shown in (1) is the load flow Jacobian (J_I), where the subscript I indicates the injection (load) sensitivity.

$$J_I = \begin{bmatrix} \frac{\partial P_I}{\partial \theta} & \frac{\partial P_I}{\partial |V|} \\ \frac{\partial Q_I}{\partial \theta} & \frac{\partial Q_I}{\partial |V|} \end{bmatrix} \quad (1)$$

The power flow is refined by classifying generators as PV buses (at steady state, the generator governor constrains the real power P and the voltage regulator constrains the voltage magnitude V). All other buses are classified as PQ buses (constraining the real power P and reactive power Q). This is

accomplished by removing the $\frac{\partial Q_{I(PV)}}{\partial |V_{(PV)|}}$ elements from the

rows and columns corresponding to PV buses. This removal results in a new matrix J_{Ir} , where the r subscript indicates the reduction. Construct J_{Ir} by pre- and post-multiplying with the selection matrix (M), as shown in (2). M is an identify matrix, with the columns corresponding to the Q_{PV} elements removed.

$$J_{Ir} = M^T J_I M \quad (2)$$

The application of these constraints results in a full rank J_{I_r} matrix as long as it represents one connected subnet. If islands are represented in the J_{I_r} matrix, the matrix must be partitioned and each island solved independently.

Similarly, the line flow Jacobian (J_F) is constructed as shown in (3) by expressing the sensitivities with respect to line flows instead of injections, as in the load flow Jacobian (J_I).

$$J_F = \begin{bmatrix} \frac{\partial P_F}{\partial \theta} & \frac{\partial P_F}{\partial |V|} \\ \frac{\partial Q_F}{\partial \theta} & \frac{\partial Q_F}{\partial |V|} \end{bmatrix} \quad (3)$$

By combining the information contained in the load flow Jacobian and the line flow Jacobian, the sensitivity between the bus injections and the line flows (J_{IF}) is related. For this derivation, begin with the line flow Jacobian and constrain V_{PV} by multiplying with M . Multiply by the inverse of J_{I_r} to translate the network state sensitivity to a constrained injection sensitivity, and then multiply by M^T to expand this result to the full injection vector. This reinserts zeroes for the P_{PV} elements.

$$J_{IF} = J_F M J_{I_r}^{-1} M^T \quad (4)$$

The relationship between incremental load injection and incremental line flows is then given by (5). This is the equation used by the distributed controllers to select loads for removal in order to reduce network overload, keeping the system interconnected to avoid a cascading outage.

$$\begin{bmatrix} \Delta P_F \\ \Delta Q_F \end{bmatrix} = J_{IF} \begin{bmatrix} \Delta P_I \\ \Delta Q_I \end{bmatrix} \quad (5)$$

Although the calculation of J_{IF} in (4) is shown with a matrix inversion, in practice, the calculation is more numerically stable and computationally efficient if implemented with matrix factorization and backward substitution. This sensitivity matrix (J_{IF}) can be calculated in advance and stored in preparation for the need to calculate the effect of various control actions. Note that the full matrix does not need to be calculated. Using numerical methods that optimize backward substitution, only the portions of J_I and J_F that correspond to the specific control actions and line flows need to be calculated. This is useful if the reason for the overload is due to the removal of a transmission asset due to a fault. The removal of an asset changes the network topology and therefore invalidates the sensitivity matrices that the distributed controllers have calculated. Conveniently, PMUs provide a direct measurement of the network state, which enables fast vectorized calculation of the J_I and J_F matrices [9].

The distributed controllers retrieve the set of control actions and their respective incremental injections that are available from their local controllers and translate that information into incremental line flows. This information is then transmitted to the initiating distributed controller. The initiating distributed controller evaluates the control actions available from the local controller and decides the appropriate action to execute.

Among the set of control actions, if any individual action relieves the overload by itself, the distributed controller executes this action. If multiple actions are available, it chooses the action with the minimum load-shedding impact. If no action can relieve the overload by itself, but other actions contribute toward this goal, the distributed controller chooses the action corresponding to the highest Jacobian sensitivity.

Each action is executed and the query process is repeated in an iterative feedback manner. If no actions contribute toward relieving the overload, the other distributed controllers are alerted to the impending trip, as described in Section II. If other overloads are pending, the next highest priority overload is selected and the query process is repeated. If sufficient time remains before the trip, the system warns the operator of the impending action and waits for operator intervention. If no operator intervention occurs, the selected action is the commanded directly by the distributed controller to one of its associated local controllers or indirectly via the supervising distributed controller.

IV. PERFORMANCE

Using local and wide-area information, the distributed controller has been tested with the 39-bus New England test system shown in Fig. 3. The system is divided into four areas, each with a single distributed controller. For clarity, the distributed and local controllers themselves are not shown in Fig. 3. Other partitions of the system among the controllers are possible and provide similar results. The selection of areas over which each distributed controller operates is primarily a function of implementation constraints and substation locations.

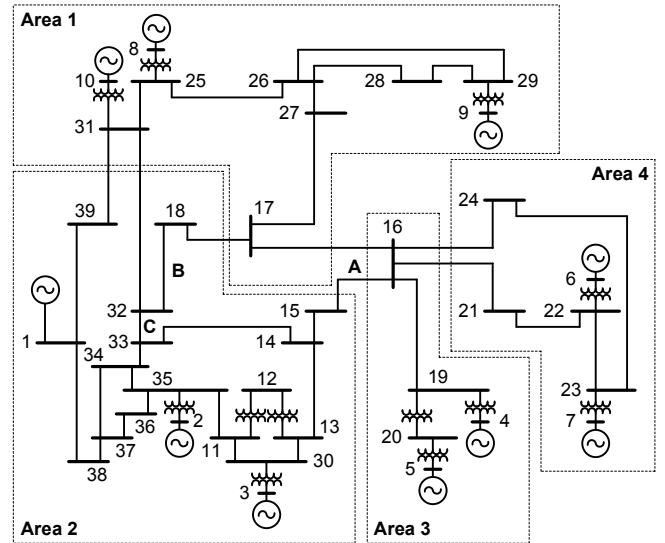


Fig. 3. New England test system with 39 buses.

For testing, the network is approximated with the short line model and line parameters specified in the 39-bus test system. Lines have complex series impedances and purely reactive shunt admittances. The network generation is assumed to be

operating at a predetermined dispatch, where the frequency droop characteristic of the respective generation governor control systems operates to share the generation load around this operating point. The loads are modeled as a second-order polynomial with 30 percent constant impedance, 30 percent constant current, and 40 percent constant power.

Generator models include an automatic voltage regulator (AVR) limiter. The AVR limiters monitor the excitation current in the generator and limit this current to its steady-state maximum if its thermal model indicates excessive temperature. If the integral of the excess reactive power production by the generator while above its steady-state limit reaches a predetermined threshold, the reactive power from that generator is capped.

Protection elements in the local controllers are modeled by monitoring the real power flow on a line. If the real power flow exceeds a predetermined threshold, a timer is started. If the overload is not relieved by the timer expiration, then the line is removed from service. Overload thresholds are set to 150 percent of maximum N-1 power flows for most lines and 230 percent for generation feeders to conform to NERC requirements [10].

In this test case, two capacitor banks are available to be brought online. They are modeled as constant impedance loads at Buses 17 (Area 1) and 15 (Area 2) in Fig. 3.

A. Test Case Initiating Events

In order to meet NERC requirements for the emergency system condition and initiate a cascading outage, two initiating events are necessary. For the purposes of this particular test, the initiating events are a fault-induced line outage and loss of a generator. The initial line outage increases system stress by requiring a less-than-optimal distribution of power flows across the network. The generator trip pushes the network further from its equilibrium point, resulting in the overload of one or more transmission assets. For the tested case, a fault occurs at 1 second on Line A between Buses 15 and 16 (carrying 2.7 per unit [pu] of real power) and is followed by a loss of Generator 3 (supplying 6.4 pu of real power) at 2 seconds.

B. Case Without Distributed Control System

In the one-line diagram of the 39-bus system shown in Fig. 3, the system is separated into four control areas. Area 4 is a net exporter of power. The initiating fault weakens the power transfer path from this area to the rest of the network. The generator that trips is outside of Area 4 and increases the power demand over this weakened path, leading to overloads on the line connecting Buses 18 and 32 (Line B) and the line connecting Buses 32 and 33 (Line C). Without the distributed control system in operation, these overloads are resolved when the protective relays remove the lines from service at 7 seconds. The remaining network is left in a condition where Generator 2 is operating beyond its steady-state reactive power limit, resulting in the activation of the generator AVR limiter at 8.5 seconds. Following this action, the network can no longer support the reactive power demands and suffers voltage collapse, as shown in Fig. 4.

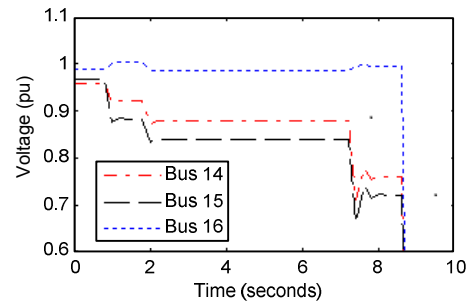


Fig. 4. Select voltages without the application of distributed control system.

C. Case With Distributed Control System

These identical initiating events were applied to the 39-bus system with the new distributed control system enabled. Following the execution of the second event, the system is in an emergency condition, enabling load-shedding control actions. The distributed controllers are set to initiate repeatedly a maximum of 30 percent load shedding for any given load bus with a cycle time of 0.2 seconds.

After the line trip and generation loss, the distributed controller for Area 2 identifies that two independent transmission assets have been removed from service and informs the other distributed controllers that the network is now in an emergency condition. The redistribution of power flow caused by these events leads to the predicted overload of Lines B and C. The local controllers at the two lines transmit the overload-related information to the distributed controller for Area 2.

Each distributed controller performs an initial analysis to determine which overload to address first. These calculations, in real time, show that Line C is downstream from Line B. Because both lines are overloaded with comparable times to trip, the distributed controllers initially focus on relieving the overload on Line B. The distributed controller for Area 2 transmits a query to the other distributed controllers requesting that they specify load shedding to reduce the flow on Line B by 2.033 pu. It receives the responses shown in Table I.

TABLE I. INFORMATION COMMUNICATED ON FIRST ITERATION

Flow Change	Bus	Injection Change	Distributed Controller
$0.0044 + 0.0057i$	17	$0.0000 + 0.0721i$	1
$0.6094 - 0.3986i$	33	$1.3469 + 0.4957i$	2
$0.2301 - 0.1383i$	36	$0.6466 + 0.2282i$	2
$0.4873 - 0.2950i$	37	$1.4180 + 0.4781i$	2
$0.0035 - 0.1050i$	12	$0.0234 + 0.2427i$	2
$0.3402 - 0.3816i$	15	$0.8230 + 0.3935i$	2

None of these control actions can individually accomplish the 2.033 pu decrease in flow, so the distributed controller for Area 2 elects to insert shunt capacitance at Bus 17 due to its minimal cost and beneficial results of a reduction in flow by 0.0044 pu. Because Bus 17 is local to Area 1, the distributed controller for Area 2 commands the associated local controller to take this action via the distributed controller for Area 1. This action takes effect at 2.2 seconds. The next query returns the responses shown in Table II.

TABLE II. SECOND ITERATION INFORMATION

Flow Change	Bus	Injection Change	Distributed Controller
$0.6111 - 0.3967i$	33	$1.3545 + 0.4984i$	2
$0.2310 - 0.1369i$	36	$0.6495 + 0.2292i$	2
$0.4893 - 0.2918i$	37	$1.4245 + 0.4803i$	2
$0.0033 - 0.1041i$	12	$0.0236 + 0.2440i$	2
$0.3415 - 0.3756i$	15	$0.8292 + 0.3965i$	2

Again, none of these control actions can individually accomplish the 1.8729 pu decrease in flow. The distributed controller for Area 2 selects to shed load at Bus 33, for an expected decrease of 0.6111 pu. Bus 33 is in Area 2, and the distributed controller for Area 2 commands the associated local controller directly to shed load. After two more iterations, the line flow overload on Line B is resolved and the overload on Line C is down to 0.0400 pu. The control options shown in Table III are received from the other distributed controllers.

TABLE III. FIFTH ITERATION INFORMATION

Flow Change	Bus	Injection Change	Distributed Controller
$0.2144 - 0.1208i$	33	$0.4871 + 0.1793i$	2
$0.2338 - 0.1238i$	36	$0.6689 + 0.2361i$	2
$0.4952 - 0.2642i$	37	$1.4662 + 0.4944i$	2
$0.0005 - 0.0995i$	12	$0.0244 + 0.2531i$	2
$0.3444 - 0.3391i$	15	$0.8652 + 0.4137i$	2
$0.0097 - 0.0056i$	35	$0.0261 + 0.0130i$	2

Now, there are four control actions (at Buses 33, 36, 37, and 15) that can relieve the remaining 0.0400 pu of overload. Bus 33 requires the minimum amount of load shedding and is selected. The distributed controller for Area 2 commands this action to the associated local controller, which results in the resolution of the remaining overloads. The cascade has been prevented, as shown in Fig. 5, and operators are now able to take steps to restore customer service. The total load shedding required by this control scheme is 3.7995 pu of real power, making up 8 percent of the total load, via five iterations of the control action and the analysis loop summarized in Table IV.

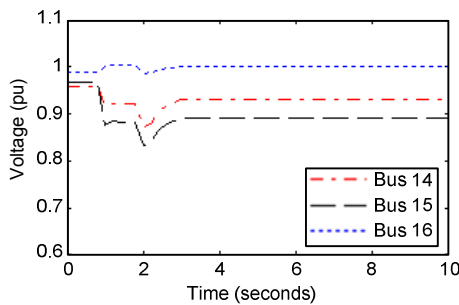


Fig. 5. System voltages with the application of the controller that includes local and wide-area information.

TABLE IV. DISTRIBUTED CONTROLLER CONTROL ACTION SUMMARY

Flow Change	Bus	Injection Change
$0.0044 + 0.0057i$	17	$0.0000 + 0.0721i$
$1.5638 - 0.9543i$	33	$3.7995 + 1.3982i$

V. CONCLUSION

A distributed controller that incorporates local and wide-area time-synchronized information has been developed and tested with the intent of mitigating the extent of cascading outages. Although this paper focuses on overload-related outages, the method is applicable to other cases as well. By combining information local to protective relays with the wide-area synchrophasor information, a set of control actions becomes available that can limit the extent of an outage. As shown in the test case, a double contingency that otherwise would have resulted in unstable system separation is instead reduced to a set of local load-shedding actions.

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VII. BIOGRAPHIES

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