Infrastructure for Protection and Control of an Active Distribution System

Sakis Meliopoulos
George Cokkinides
Georgia Institute of Technology
correspodence: sakis.m@gatech.edu

Glen Wilson
Southern Company

Kenneth Wilhelm
Avista

Rebecca Rye
Dominion Energy

Saeed Lotfifard
Washington State University

***Abstract*—**Active distribution systems protection and control faces a number of challenges resulting from the distributed energy resources that create bidirectional fault current flows and inverter based resources that affect the performance of legacy protection functions. The paper describes an autonomous, adaptive and Secure Distribution Protection (a2SDP) system for distribution systems with extra high penetration of PV and other DERs that is based on deployment of merging units along distribution feeders. Core technology is the setting-less relay (or Estimation Based Protective (EBP) relay) which is naturally the ultimate adaptive protection system, immune to fault current direction flow or level, waveform distortion or network configuration. EBP relays in totality, provide a validated high fidelity dynamic model of the entire distribution system including PVs and other DERs. The real time model is used to add features to the a2SDP: (a) detection and protection against down conductors, (b) protection of power electronic interfaces, (c) real time distribution system fault locating, (d) distribution system reconfiguration in real time (FLISR), (e) cyber-security enhancement by real time intrusion detection and command authentication, and others. The a2SDP will be demonstrated on the systems of Dominion, Southern Company and Avista. The paper describes the design of the infrastructure and will focus on the application of the system to provide protection immune to the effects from inverter based resources along the distribution system as well as the detection of downed conductors which is a major protection gap for distribution systems. The paper describes the design of the infrastructure and will focus on the application of the system to provide protection immune to the effects from inverter based resources along the distribution system as well as the detection of downed conductors which is a major protection gap for distribution systems.

Keywords—*current transformer, potential transformer, error correction, dynamic state estimation*

I. Introduction

Protection and control system of an active distribution system requires a re-thinking of the approach for legacy distribution systems. An active distribution system is defined as one with multiple distributed energy resources (DERs), such as utility size PV farms and/or rooftop PV systems, other distributed DERs, data centers, commercial building with/without DERs, industrial facilities, smart houses etc. A distribution feeder can be very long when one counts all the branches and laterals. Operating standard voltages are typically 12.47 kV, 13.8 kV, 25.0 kV and 34.5 kV with a few special cases such as 14 kV and 26 kV. In terms of power levels, these systems range for 5 MVA to 40 MVA.

The targeted system may have a high penetration of DERs which are interfaced to the system via converters. The characteristics of such a system are totally different from the traditional (legacy) distribution system that is radial with unidirectional power flow and relatively distinct separation between fault currents and load currents. Distribution systems may also experience high impedance faults, more often than transmission systems. High impedance faults occur when a phase conductor comes in contact with the earth (fallen conductors) or with a relatively high impedance object, i.e. a wet tree, and other similar scenarios. In addition, in distribution systems, high impedance faults may draw almost zero current, as in the case of a broken phase conductor fallen on asphalt, dry soil, etc. We refer to this case as an open conductor. High impedance faults and open conductors are difficult to detect with existing technology. They present additional hazards and safety issues. These conditions are protection gaps and constitute one of the most important challenges for distribution system protection and control. In any type of fault, the protection and control system must act and isolate part of the system. Since distribution systems are mostly radial, the clearing of a fault typically results in isolating the faulted part of the system plus parts of the system that are healthy. It is desirable to restore power to all healthy parts of the isolated system. This is done by reconfiguring the system following a fault and a successful clearing of the fault. For automated feeder reconfiguration, one needs to know the location of the fault, the prevailing operating conditions of the system at the time of the fault, as well as the types of switches, breakers, reclosers, etc. that exist in the system. The reconfiguration is achieved by opening and closing breakers, switches, etc. until only the faulted component of the system is isolated. One complication in implementing this process is that many switches can be operated only when there is zero current flowing through them. The sequence of switching that will achieve this limitation can be found through an optimization problem that requires knowledge of the fault location, type and location of the various switches, reclosers and breakers and the prevailing operating conditions. The setting-less relay is naturally the ultimate adaptive protection system, immune to the direction of fault current flow or the level of fault currents, waveform distortion, imbalances in voltages and currents and any changes outside the protection zone; thus providing a complete solution to the two main challenges in protecting distribution systems with high penetration of DERs: (a) varying/reduced fault currents or direction and lack of traditional signatures of fault currents in terms of negative and zero sequence quantities, and (b) changing topologies and characteristics as resources are switched in and out. The setting-less relays operate with a high fidelity dynamic model of the protection zone they are protecting. Any distribution feeder with PVs and other DERs is partitioned into a number of protection zones defined by the existing interrupting devices and each protection zone is protected by a setting-less relay. Thus any component (PV, other DERs) and any section of the distribution circuit are protected. At the same time, the setting-less relays continuously monitor and verify the dynamic model of the protection zone they protect; parameter identification methods embedded into the setting-less relays provide continuous correction and verification of the models. In its totality, the validated models from each setting-less relay form a validated high fidelity dynamic model of the entire distribution system including PVs and other DERs. The validated distribution system dynamic model is utilized to develop extensions of the setting-less relaying to solve distribution system protection gaps as well as provide fault location and post fault optimization of the distribution feeder. The proposed infrastructure should be cable of accommodating the following features: (a) detection and protection against down conductors, (b) protection of power electronic interfaces, (c) real time distribution system fault locating, (d) distribution system reconfiguration in real time (fault location, isolation and service restoration (FLISR)), (e) operation of setting-less relays under reduced measurements in case of communication loss, (f) continuous dynamic model validation (feeder, PV, other DERs), and (g) cyber-security enhancement by real time intrusion detection and command authentication.

To ensure the proper operation of above features in real time, Georgia Tech is collaborating with Southern Company, Dominion Energy, Avista and Washington State University to develop an infrastructure based on the use of merging units together with numerical relays for a reliable protection and control system for active distribution system with the features mentioned above. The proposed system has been coined **a^{2}SDP** system (**a**utonomous, **a**daptive and **S**ecure **D**istribution **P**rotection).

A core technology for the proposed system is the dynamic Estimation Based Protective relay (EBP relay), a.k.a. SettingLess Protective relay (SLP relay). The setting-less relay is naturally the ultimate adaptive protection system, immune to the direction of fault current flow or the level of fault currents, fault current composition of pos/neg/zero sequences, waveform distortion and any changes outside the protection zone; thus providing a complete solution to the two main challenges in protecting distribution systems with high penetration of DERs: (a) varying/reduced fault currents and direction with new characteristics, for example lack of negative sequence fault currents, and (b) changing topologies and characteristics as resources are switched in and out. The setting-less protective relay has been inspired from the differential protection function as it is illustrated in Figure 1.

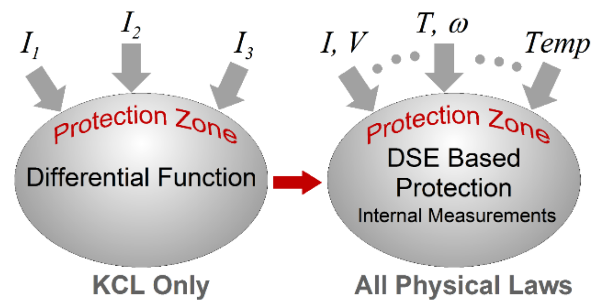

Figure 1: Conceptual Illustration of the EBP Relay

In differential protection the electric currents at all terminals of a protection zone are measured and their weighted sum must be equal to zero (generalized Kirchoff's current law). As long as the sum is near zero no action is taking. In the EBP relay, all existing measurements in the protection zone are utilized and compared to the dynamic model of the protection zone via a dynamic state estimation procedure that quantifies how well the measurements satisfy the mathematical model. This approach has been named setting-less protection because of the simplicity of use without the challenges associated with the coordination with other relays. The EBP relay performance is independent of fault current levels and direction, waveform distortion, and other protection functions, i.e. it does not need to be coordinated with any other protection functions. It detects all faulty conditions including those that do not draw fault current such as a down conductor on asphalt. Because of this property the EBP relay provides full protection (against all abnormal and intolerable conditions) to any protection zone.

II. Distribution System P&C Architecture

The basic configuration of the proposed system is illustrated in Figure 2. Note that the design introduces the concept of nodes. A node is equivalent to a "control house" for a section of a distribution circuit. The distribution circuit section size is arbitrarily selected. For example, for a node can be a feeder with high concentration of loads and other resources including two to three miles of distribution lines. Nodes containing less dense feeders may include considerably higher length of distribution circuits. Figure 3 illustrates an example of a node and the associated part of a feeder. Figure 4 illustrates the basic equipment in a node, as well as the communications structure. The feeder section associated with this node includes three reclosers, two house clusters with 50 kVA rooftop PVs, one utility size PV farm, a commercial building and a voltage correcting capacitor bank. The node monitoring and control equipment includes an Ethernet switch, a GPS antenna/receiver, and a computer. Along the feeder section seven data acquisition systems (merging units) are located. While other technologies can be used, we are developing the data acquisition design based on merging units since we believe that these will be the devises of choice for the near future.

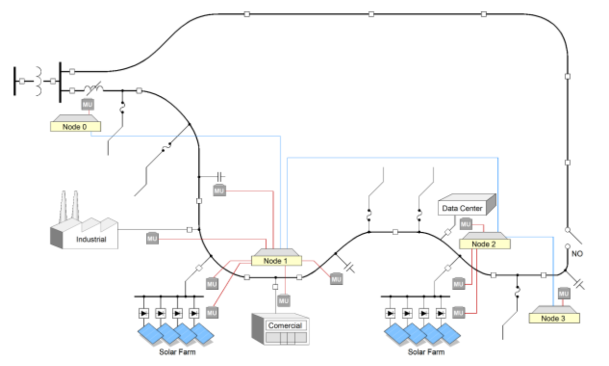

Figure 2: Basic Configuration of D-PAC

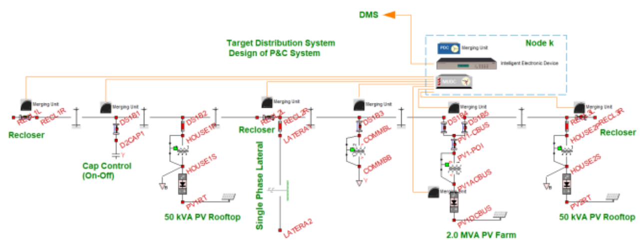

Figure 3: Basic Concepts of a Distribution System Node

It is important to realize that the data traffic in the a^{2}SDP is enormous. The architecture of the communication of the a^{2}SDP is critical for the success of this project. The architecture must be as simple as possible but also to accommodate all the applications of the a^{2}SDP. These applications are: (a) assurance that all measurements are GPS synchronized with time precision of one microsecond. (b) assuring that all protection functions are executed in real time with data being available to all relays in a timely manner, (c) assurance that the data will be available at the master a2SDP for executing the applications at the feeder level in a timely manner, and (d) assuring that controls are transmitted to the proper device in a timely manner. The data flow design is illustrated in Figure 5.

The approach includes redundant buffers for sample value data created at each network node, redundant data buffers for phasors at each node as well as accommodation of telemetry data, both sample values and phasors. The architecture also enables full parallelization of the analytics, for example each logical node (EBP relay) is assigned to one core of a multi-core computer, etc. It has simplicity, speed and compatibility with IEC 61850.

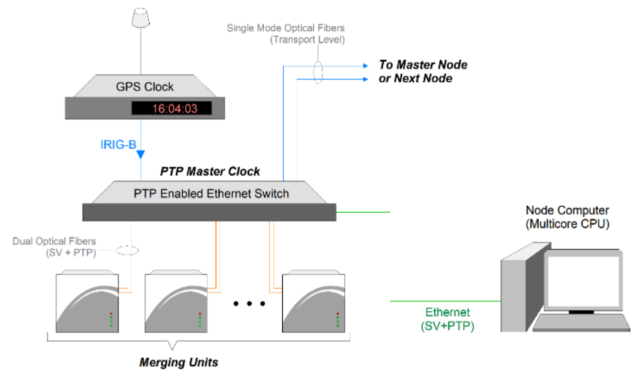

Figure 4: Basic Equipment – Cyber Assets - and Interconnections in a Node

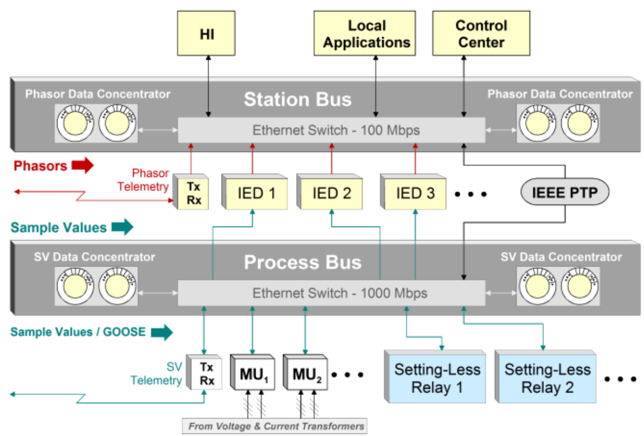

Figure 5: Overall Architecture of Data Management Scheme

The communications between the entities of the system are described next. These are communication requirements for the implementing the PTP standard, Precision Time Protocol, IEEE Std. 1588, merging unit to network node communications and network node to substation node communications.

III. The Concept of a Node – Hardware and Software

The node comprises equipment to (a) deliver timing signals to the data acquisition devices for synchronization (b) facilitate the collection of the data generated by the data acquisition devices, (c) time align the collected data for use in the various applications, (d) perform local analytics, and specifically protection functions, (e) transform raw time domain data into phasors and stream phasor data to the master a^{2}SDP node.

The communication and data acquisition equipment comprising a single node is illustrated in Figure 6.

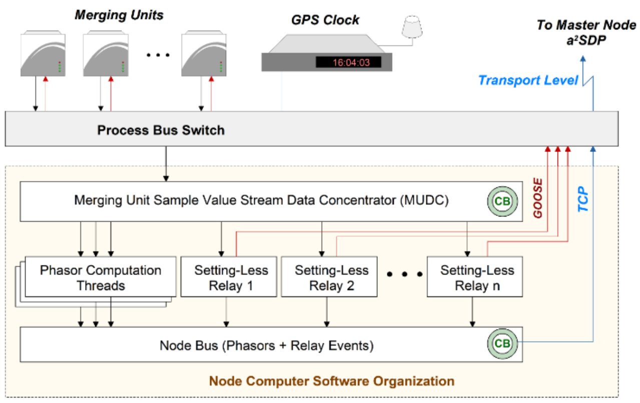

Figure 6: Basic Software Organization in a Node

A set of merging units monitor system voltages and currents at various locations. The merging unit sample value (SV) streams are transmitted to a PTP enabled Ethernet switch via optical fiber pairs. A GPS based clock provides the time reference source enabling the synchronization of the merging unit sampling via the IEEE-1588 precision time protocol (PTP). Note that the GPS reference clock may be integrated into the switch or be in a separate enclosure. In the default configuration the Ethernet switch will be configured as a Master Clock. However, in the event of a local GPS clock failure, the switch can act as a slave or transparent clock obtaining timing information from other switches in the wide area network.

A multicore CPU computer (Windows 10 PC) is connected to the switch via a wired Ethernet link. It receives and processes the SV streams generated by the merging units. This computer executes the WinXFM software which implements the seven proposed a^{2}SDP node functions.

IV. Protection Functions

As mentioned already, a core technology for the proposed system is the dynamic **E**stimation **B**ased **P**rotective relay (EBP relay), a.k.a. **S**etting-**L**ess **P**rotective relay (SLP relay). The EBP relay requires a high fidelity model of the protection zone which needs to be entered and tested at the time of commissioning. It operates on data collected with typical data acquisition systems for relays, preferably merging units. Industry standards for the rate of data are 80 samples per cycle (or 4,000/4,800 samples per second for 50 Hz/60 Hz systems) and 256 samples per cycle (or 12,800/15,360 samples per second for 50 Hz/60 Hz systems). The data collected with the data acquisition system represent actual measurements that are used for the dynamic state estimation. In addition, by knowing the topology and the mathematical model of the protection zone, a number of additional measurements can be generated by using the physical laws that govern the operation of the protection zone. We refer to these as "virtual measurements" if the corresponding quantity is known with certainty (noiseless measurements) such as the sum of currents at a node of the protection zone, or "derived measurements" if the corresponding quantity is derived as a linear combination of other measurements, for example the voltage on a branch of a loop in which all the other branch voltages are measured. We occasionally introduce pseudo-measurements if the quantity is expected to be in a certain numerical range, such as the voltage of a grounded node. These measurements are automatically added to the measurement set by an algorithm that considers the topology and the mathematical model of the protection zone. The addition of virtual, derived and pseudo-measurements increases the measurement set for the EBP relay, resulting in better performance of the relay. The name setting-less relay was coined because it requires simplify settings, such as maximum operating temperatures of a device or other specific physical operating limits depending on the nature/physics of the protection zone. The flow of the algorithm of the EBP relay is shown in Figure 7.

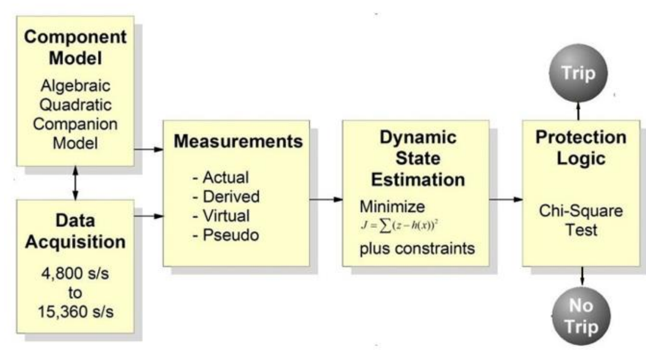

Figure 7: Functional Organization of the EBP Relay

The EBP relay, by virtue of the dynamic state estimation, provides a validated model of the protection zone as well as parameter identification via dynamic parameter estimation to fine tune the models of the protection zones. Note that a distribution feeder with all the connected resources, i.e. customers, PV installations, other DERs, etc. is partitioned into a number of protection zones. The boundaries of the protection zones are at interrupting devices, i.e. breakers, reclosers and switchers that can interrupt fault currents. For each protection zone one EBP relay will be dedicated for the protection of the zone. Thus the entire distribution feeder with all the connected resources is covered. This means that the totality of the EBP relays will provide the validated models of all protection zones, i.e. the entire feeder and all connected resources. The validated model of the entire feeder will be used to implement the remaining features of the proposed **a^{2}SDP** system: (d) real time distribution system fault locating, (e) distribution system reconfiguration in real time (fault location, isolation and service restoration (FLISR)), (g) continuous dynamic model validation (feeder, PV, other DERs), and (h) cyber-security enhancement by real time intrusion detection and command authentication.

The setting-less relay has another advantage, it provides a reliable solution to the problem of detecting and protecting against downed conductors. Downed conductors is a well-known protection gap that results in many fatalities annually. Every year many lose their lives because of downed conductors that remain energized on the ground. There is no 100% reliable method to detect downed live conductors. In past research, the authors developed a relay that uses the neutral for communications to detect and trip live downed conductors (patent #5,341,265, A C Westrom, A. P. Sakis Meliopoulos, G. J. Cokkinides, Method and Apparatus for Detecting and Responding to Downed Conductors, U.S. Patent #5,341,265, August 23, 1994). Prior research indicated the effectiveness of this relay but implementation of the method turned out to be expensive. Note that this system is a dedicated system serving the purpose of detecting and protecting against down conductors; there are no other uses for this system. The new work, incorporates the detection of live downed conductors within the setting-less relay and trip the circuit. Specifically, the EBP relay detects a downed conductor with certainty. It does not provide the location of the down conductor, only the protection zone of the distribution system where a downed conductor has occurred. Identifying the protection zone where a downed conductor occurred is sufficient to isolate the downed conductor and therefore it provides a full solution. Sample performance of a setting-less relay in the detection of downed conductors is provided in Figure 8.

This function is presently undergoing thorough testing with numerical experiments. Note that the cost of adding protection against downed conductors is minimal assuming that the proposed infrastructure and system for the protection and control of a distribution system is in place. The proposed solution simply represents additional software to be installed in the system.

V. REAL TIME FLISR

Real-time post-fault service restoration is a basic function of a modern distribution system. The proposed infrastructure enables real time fault locating and subsequent isolation and service restoration. We describe both below.

Fault Locating: Phasor based fault locating in distribution system must consider the typical conditions in a distribution system. In general, the distribution system is connected to multiple loads, and devices along its length. Measurements can be distributed along the distribution feeder. In addition, measurements can be of different technologies with widely varying accuracy. These characteristics are symbolically captured in Figure 9.

We define the general problem of fault locating in reference to Figure 9. The location and type of fault is not known. We designate the location of the fault with the variable ℓ. We formulate the problem of fault locating as a state estimation problem, which will determine the best estimate of the fault location ℓ. The state of this system is defined as the voltages at each node of the system plus state variables that define the fault location and type. Meters are available along the feeder at arbitrary locations. Some meters are three phase, some are single phase. In general, the availability of meters is arbitrary and it may also evolve with time. Measurements can be also synchronized voltage and current phasors or non-synchronized measurements of voltage and current magnitudes or real and reactive power.

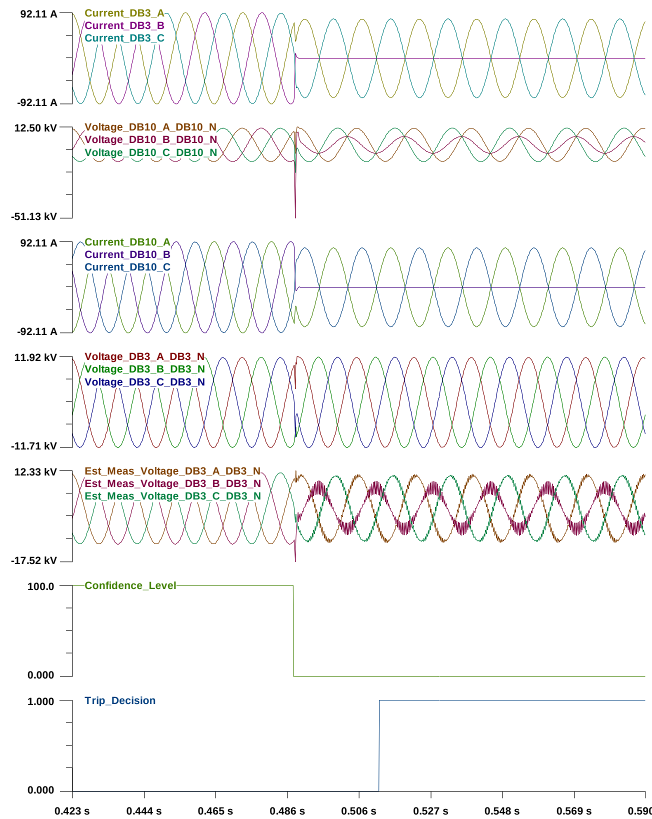

Figure 8: Performance of a Setting-less Relay: Actual/Estimated Measurements, Confidence Level, and Chi Square Value

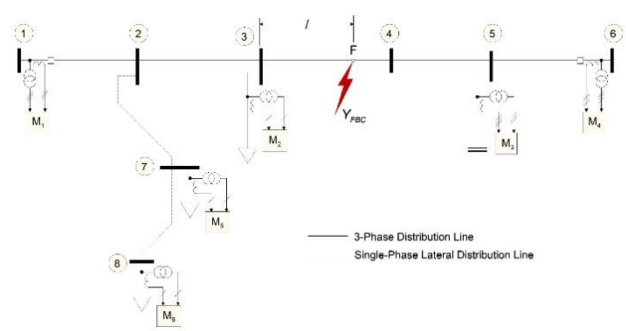

Figure 9: Example Distribution Feeder with Measurements and Fault

The method is designed to include any available measurement in the distribution system. Let m_i denote the metering device. The measurements are represented symbolically as follows:

$$z = \left[\tilde{V}_{1AN}^{m_1}, \tilde{V}_{1BN}^{m_1}, \tilde{V}_{1CN}^{m_1}, \tilde{I}_{12A}^{m_1}, \tilde{I}_{12B}^{m_1}, \tilde{I}_{12C}^{m_1}, \tilde{V}_{3CN}^{m_2}, \tilde{I}_{30C}^{m_2}, ... \right]^T$$

In distribution systems, especially in older systems, the availability of measurements is limited. In these cases, using only the available actual measurements, the system may not be observable. However, in addition to the actual measurements, there are derived and virtual measurements that augment the measurement set and make the distribution system observable. As a matter of fact, the addition of these measurements will provide redundancy in measurements which will enable other important features of the state estimator, such as detection and identification of bad measurements.

The fault locating problem is formulated as a dynamic state estimation problem. The state estimation method requires that all the measurements, actual, virtual and derived be expressed as a function of the state. Therefore, for the formal introduction of the state estimator the measurements are expressed in terms of the state. For this purpose, the model of the distribution feeder must be known. The formulation is omitted due to lack of space.

Service Restoration: The fault locating, isolation and service restoration (FLISR) problem is defined as follows. Upon the occurrence of a fault, the protection and control system of the distribution system will respond and will leave the system in a state of partial service. This state can be defined in terms of open/closed breakers, reclosers, switches, etc. The system topology, status of switches and operating conditions of a given distribution system is uniquely determined by switch status vector *u* which results in a system state described with the vector x. The objective of FLISR is to find the optimal switching sequence that leads to the optimal system topology which minimizes total real power of disconnected loads while accounting for switching constraints. The optimal switching sequence is defined in the sense that it results in minimum cumulative transition cost from the initial post-fault topology to the optimal topology.
We formulate this problem as a Dynamic Programming problem with finite horizon (number of stages). The sequence of switchings is defined as actions taken at stages, each stage is a length of time sufficient for the communications to send the command and the switches to operate. The state of the system is defined as a distinct state at a specific stage. Every switch has a certain on/off status in stage k. For the j-th switch, let $u_j(k)$ be the switch status at stage k. Then $u_j(k)=1$ when the switch is closed and $u_j(k)=0$ when the switch is open. At each stage, the state of the system is defined as the set of switch statuses for all switches:

$$x[k][i] = \left\{ u_j(k),\ j = 1, 2, \dots n; \quad j \in I(i) \right\}$$

The initial state of the system is set to be the post-fault state of the system. We define this state $x[0][0]$ as the only state at stage 0. A state $x[k][i]$ represents that the system topology is at state i at stage k.

Transition Cost: At stage k, the system can assume N possible states ($x[k][i],\ i = 1, 2, \dots N$) corresponding to all possible system topologies. A state transition from x[k][m] at stage k to state x[k+1][i] at stage k+1 is feasible only when: (a) there is only one switch state change and (b) the switch state change is feasible, i.e. it does not violate switch operating constraints. Note, the state transition is feasible when a state transitions to itself.

When the transition is feasible, the transition cost $\mathrm{TC}(x[k][m] \to x[k+1][i])$ is 0; when the transition is infeasible, it is set to ∞ (or a very large value):

$$\mathrm{TC}(x[k][m] \to x[k+1][i]) = \begin{cases} 0, & \text{the transition from } m \text{ to } i \text{ is feasible} \\ \infty, & \text{the transition from } m \text{ to } i \text{ is infeasible} \end{cases}$$

It is important to note that the feasibility of the transition is dependent upon the operating state of the system. For example, if m is a sectionalizer switch which is closed in the state x[k][m] and there is flow of current through that switch in state x[k][m], then the transition is infeasible. If no current flows through the switch the transition is feasible.
Cost of Operation: The cost of operation of an infeasible topology is assigned to be infinite. On the other hand, for a feasible topology, the "cost" of operation can be defined in several alternate ways, depending on the objective we need to achieve: (a) number of customers not served, (b) total loads not served, and other.
The cost of operation Cost[k][i] is defined as:

$$\mathrm{Cost}\left(x[k][i]\right) = \begin{cases} U(x[k][i]), & \text{State } i \text{ is feasible} \\ \infty, & \text{Otherwise} \end{cases}$$

where $U(x[k+1][i])$ is one of the objectives defined above, i.e. (a) number of customers not served, or (b) total load of customers not served. In subsequent discussions, we use the function (b).

Note that the cost of operation only depends on system topology and it is independent of stage number. Therefore, without loss of generality we can write

$$\mathrm{Cost}\left(x[k][i]\right) = \mathrm{Cost}\left(x[*][i]\right).$$

The cost of operation can be extended to incorporate more comprehensive indices. For example, cost of system real power loss and harmonics can be included.
Computation of Optimal Cost: The final computational procedure for the problem is the computation of the optimal

cost of moving the system from the initial condition x[0][0] (stage 0, state 0) to a state x[k][i] (stage k, state i). Let OptimalTotalCost(x[k][i])=c*(x[k][i]) be the optimal total cost of the transition of the system from the state at the initial stage to the present stage k, state i. Assume the optimal total cost has been computed for all states at stage k, then the algorithm to compute the optimal total cost for stage k+1, state i is given by the following recursive formula:

$$c^{*}\left(x[k][i]\right) = Min\left\{c^{*}[k-1][j]\right\} + TC(\ ) + \mathrm{Cost}\left(x[k][i];\quad j=1,2,3,....\right)$$

Every state i at stage k also has a variable D[k][i], which stores the state number of the previous stage that is in the optimal path from initial state at stage 0 to the current state, this state is called the parent state of the current one. The parent states are not necessary for computation of the optimal cost, but are needed for backtracking the optimal path (control sequence) from the final to the initial state. The path provides the optimal switching sequence.

An example case of a three feeder distribution system will be provided during the presentation. The single line diagram of the system is provided in Figure 10.

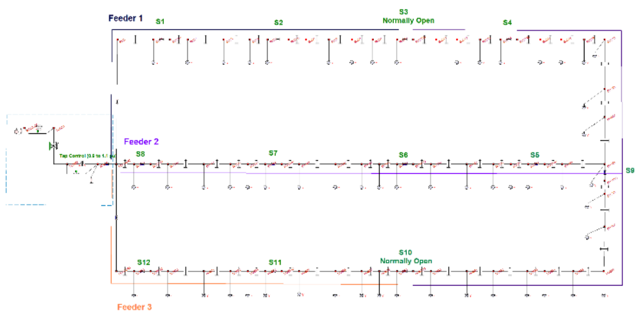

Figure 10: Example 3-Feeder Distribution System

VI. CONCLUSIONS

Today, there is technology to develop a protection and control infrastructure for distribution systems that will provide reliable protection and control addressing the new challenges of active distribution systems. The infrastructure also provides full automation of distribution system operations. The new technologies provide advanced solutions for reliable protection of the distribution system, situational awareness to the operator and in general provides the real time model of the distribution system that can be used for an array of applications. The investment required for this implementation is within what proactive utilities are presently doing.

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