Smart Grid Technologies for Autonomous Operation and Control

A. P. Sakis Meliopoulos, *Fellow, IEEE*, George Cokkinides, *Member, IEEE*, Renke Huang, *Student Member, IEEE*, Evangelos Farantatos, *Student Member, IEEE*, Sungyun Choi, *Student Member, IEEE*, Yonghee Lee, *Student Member, IEEE*, and Xuebei Yu, *Student Member, IEEE*

***Abstract*—This paper presents a new smart grid infrastructure for active distribution systems that will allow continuous and accurate monitoring of distribution system operations and customer utilization of electric power. The infrastructure allows a complete array of applications. The paper discusses four specific applications: a) protection against downed conductors; b) load levelization; c) loss minimization; and d) reliability enhancement.**

***Index Terms*—Data accuracy, data communication, GPS synchronization, optimization methods, PMU, power system state estimation.**

I. Nomenclature

GPS	Global positioning system.
UGPSSM	Universal GPS Synchronized Meter.
PMU	Phasor measurement unit.
SE	State estimation.

II. Introduction

WITHIN the near future, the distribution system will be transformed from a passive to an active grid with the integration of customer and utility resources. The residential load profile will change from its current condition (resistive and inductive) towards an inverter-based load profile, since houses may have renewable sources, PHEVs, and storage devices that interface to the system via power electronics based inverters. Furthermore, utilities are expected to invest in the modernization of the distribution grid by installing distributed generation resources, storage systems, dynamic VAR support systems, reclosers, switches, etc. All these resources have to be optimally and autonomously coordinated, in order to achieve optimal system level operation which will be secure, and environmentally friendly. Financial benefits for the utilities stem from minimized losses, peak load reduction, and reliability improvement. Our goal is to create an infrastructure that will be able to accommodate all these changes without affecting customer convenience, in an economically attractive manner and within manpower capabilities. The last requirement leads to new levels of automation.

The proposed infrastructure is a combination of distributed hardware and software tools that will modernize the distribution grid from the house to the power plant. The ultimate goal of the proposed infrastructure is a system level demand, delivery, and reliability optimization. Demand optimization can be achieved through load levelization and peak load reduction, while delivery optimization can be achieved through loss minimization. The proposed infrastructure will also lead to dramatic reliability enhancements of the distribution system.

III. Proposed Infrastructure

We propose an innovative infrastructure that will enable real-time management of all the available components of the grid, either utility or customer owned, with the ultimate goal being to operate the system optimally and in a secure way. The proposed infrastructure is a combination of software and hardware tools. Its major components are a) a real-time monitoring system and b) optimization algorithms that will modernize the existing grid and add further functionality to the distribution management systems (DMS). Specifically it consists of a high fidelity real-time monitoring system that is based on advanced metering infrastructure (AMI) and a three-phase state estimation algorithm which filters the measurements to give the real-time model of the system. The results of the state estimator are used as an input to an optimization algorithm responsible for generating real-time control signals through which all the available devices (capacitor banks, distributed resources, etc.) will be coordinated to achieve system level optimal operating conditions. In the following paragraphs we will elaborate on the major components of the proposed infrastructure.

As far as the AMI is concerned, it is expected that house meters will be massively deployed, enabling active control, and monitoring of residential loads. However, data obtained from house meters are not sufficient to achieve full observability of the whole distribution feeder. In order to be able to optimally control and coordinate all available devices (such as capacitor banks, voltage regulators, and utility-owned distributed generation resources or storage devices) we need to achieve full observability of the feeder, potentially at every node of the system. Towards this goal we suggest the deployment of a novel smart

Manuscript received September 22, 2010; accepted October 27, 2010. Date of current version February 18, 2011. This work was supported in part by the Department of Energy under Oroject DE-0000117, in part by GE Energy, Power System Engineering Research Center, and in part by Hyundai Heavy Industries. Paper no. TSG-00129-2010.

The authors are with the School of Electrical and Computer Engineering, Georgia Institute of Technology, Atlanta, GA 30332-0250 USA (e-mail: sakis.m@gatech.edu; cokkinides@comcast.net; rhuang6@gatech.edu; vfarantatos@gatech.edu; schoi35@mail.gatech.edu; yongalee@gatech.edu; and yuxb1101@gmail.com).

Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TSG.2010.2091656

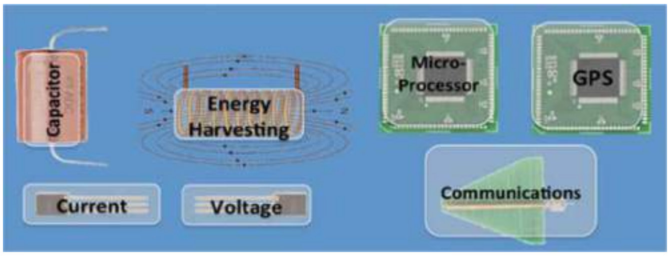

Fig. 1. Conceptual view of self-powered GPS-synchronized, communications-enabled smart meter.

metering device which we will refer to as the "Universal GPS Synchronized Meter." We propose this to be deployed on the poles of distribution lines and along the distribution feeders. The major characteristics of the UGPSSM are the following:

- low cost;
- power autonomous;
- synchronized voltage and current phasor measuring capability;
- two-way communications capability.

The major components of the proposed device are illustrated in Fig. 1. It consists of an energy harvester, a voltage and a current sensor, a GPS sensor, a microprocessor, and a wireless communication component. We propose this to be deployed on the poles of distribution lines and along the distribution feeders. Specifically, the device makes use of the magnetic field around the power line to be self-powered. A voltage sensor and a current sensor that can measure the magnitude and phase angle of the corresponding waveform are also used. In addition, it combines a GPS receiver, a microprocessor, and a RF communication component to enable two-way communication of the measured data with GPS time stamps.

This component is an advanced meter that performs the role of merging unit (MU). It senses voltage and current analog data with high sampling rate and converts the measured data from analog to digital. The digital data are sent to the process bus directly or via a concentrator with high data rates (Gbps). Wireless communication is used between UGPSSM and process bus.

The second major component of the real-time monitoring infrastructure is the state estimator. Specifically, real-time measurements obtained from the AMI infrastructure (house meters and UGPSSMs) will be used as an input to the state estimation algorithm that will fit the data into a highly accurate system model, providing a real-time monitoring of the system. Because of the presence of GPS synchronization, the state estimation process can be performed for subsections of the system and the results are used to synthesize the overall state of the system (distributed state estimation). The results of the state estimator are used as an input to advanced optimization algorithms—these applications are discussed later.

In summary, Fig. 2 illustrates the major components of the proposed infrastructure and the way this is implemented. Measurements obtained from AMI (UGPSSMs and house meters) are sent to a data concentrator (IED) where the distributed state estimator processes them and sends the local state estimate to a central location (Distribution Management System—DMS) where the system model and state is synthesized (real-time model). The real-time model is used as an input to optimization algorithms. The output of the optimization algorithms are real-time control signals that are sent to each controllable device.

IV. Communications

The proposed system is dependent upon a distributed reliable and high-speed communication system. The deployment of a novel metering device, the UGPSSM, as illustrated in Fig. 1, provides this system. UGPSSM collects measurements from the circuits of the distribution system at high sampling rate and sends the digital data directly to a concentrator by wireless communication using IEC 61850 standard [1]. The wireless communication distance between concentrator and UGPSSM is relatively short because concentrators can be deployed at strategically placed locations along the distribution system as illustrated in Fig. 3. For this reason time latencies introduced by the communication system will be very short and they will not deteriorate the performance of the system. Also, unlike traditional analog transmission via wires, digital transmission is immune to data distortion. The data transmission which has high frequency (GHz) point to point communications is cost effective. Furthermore the UGPSSM performs GPS-synchronized measurements that provide accurate timing to 1 μs accuracy.

In the proposed infrastructure, a concentrator (IED) monitors, protects, and controls a specific distribution area where several UGPSSMs capture the data as described in Fig. 3. The UGPSSM transmit to the concentrator real-time data along with the device models and connectivity data. The concentrator, then, performs the state estimation process autonomously and the computed state is transmitted to the Modern Distribution Management System (MDMS) where the entire distribution system state is synthesized. As a result the MDMS is equipped with the real-time model of the entire distribution system. Various optimization models can be exercised that may determine control actions that will be transmitted to the field devices. The state estimation is performed autonomously. The process is described next.

V. Autonomous State Estimation

State estimation is one of key features for implementing the proposed Advanced Distribution Management System (ADMS); it extracts a highly accurate real-time operating condition of system from the measurement data. The operation and control of the smart grid may result in frequent reconfigurations of the network topology. Thus, the autonomous process should automatically detect system changes and reconfigure the state estimation problem. This level of automation is possible with the proposed scheme and we refer to it as autonomous state estimation [2]. A brief description follows.

A. Three Data Sets

The implementation of autonomous state estimation is based on three key data sets for each component in the smart grid: 1) connectivity data; 2) device model; and 3) measurements. The three data sets are described next.

1) Connectivity: Device components of the smart grid are linked through connecting points, i.e., nodes and buses. The connectivity data refer to these connections, and are required

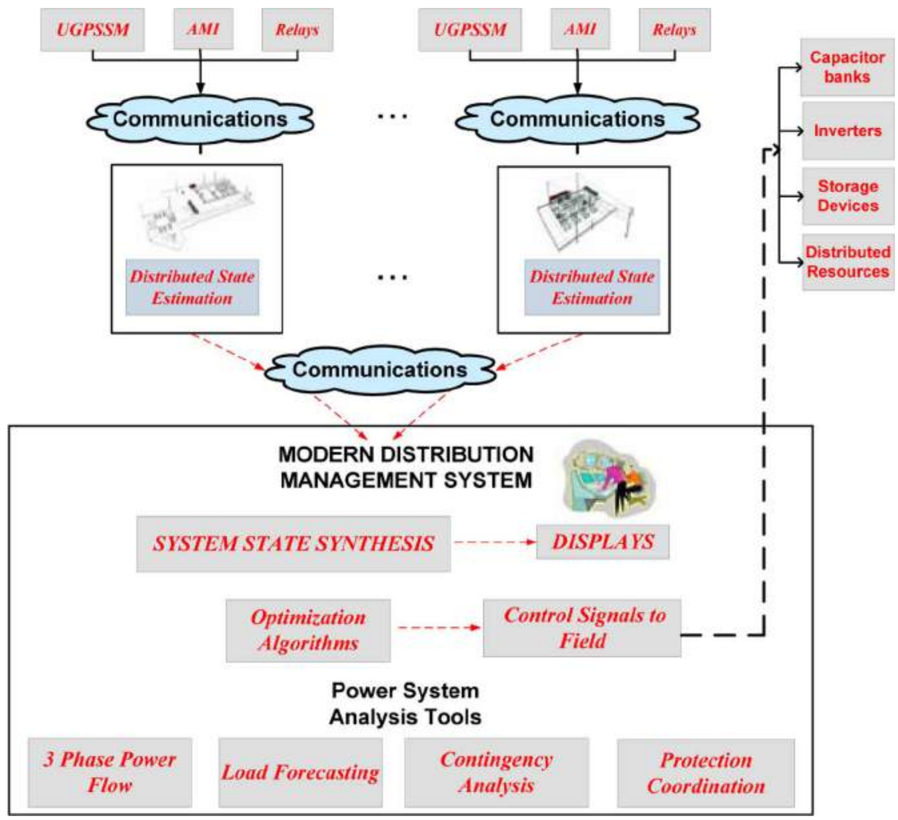

Fig. 2. Proposed infrastructure.

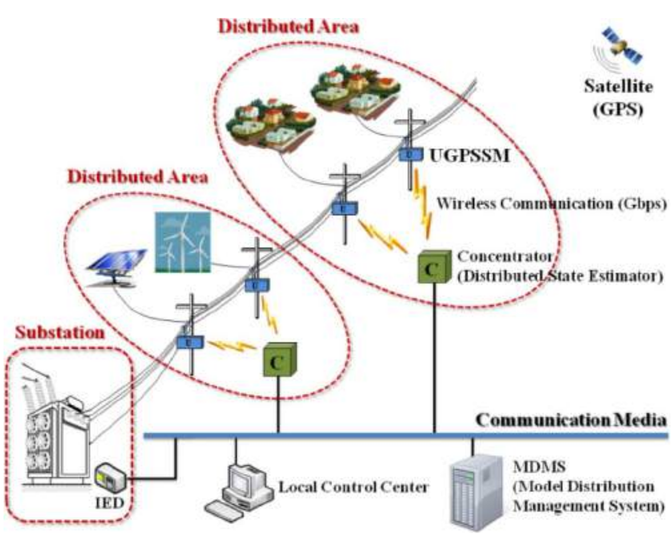

Fig. 3. Proposed communication network system.

to identify the grid topology. The connectivity data are used for the network configuration.

2) Device Model: The purpose of state estimation is to obtain best estimated data that fits to the system model. Hence, the model of each device is needed to autonomously generate the measurement model, $h(x)$ along with measurement data.

Meanwhile, single-phase laterals and loads in distribution systems can yield system imbalance and asymmetry. Therefore, detailed models of devices are needed to provide high fidelity modeling of the distribution network. The proposed approach is based on physical, breaker-oriented models that include neutral and grounds. For example, Fig. 4 describes the parameter setting of a distribution feeder which determines its device model. Note that other well-known parameters can be derived from the physical parameters, such as positive, negative, and zero sequence parameters. It is important to note that sequence parameters are not used in this approach since they represent a certain approximation of the component model.

The device model is expressed in standard form as follows:

$$\begin{bmatrix} I \\ 0 \end{bmatrix} = \begin{bmatrix} A_{11} & A_{12} \\ A_{21} & A_{22} \end{bmatrix} \begin{bmatrix} V \\ y(t) \end{bmatrix} - \begin{bmatrix} 0 \\ b(t-h) \end{bmatrix} + \begin{bmatrix} 0 \\ f(t) \end{bmatrix}$$
$$f(t) = \begin{bmatrix} \vdots \\ [V \quad y(t)]\, q_i \begin{bmatrix} V \\ y(t) \end{bmatrix} \\ \vdots \end{bmatrix} \tag{1}$$

where I is the current vector, A is the admittance matrix, V is the voltage state vector, $y(t)$ is the internal state vector, t is the time measured, $b(t-h)$ is the past history, h is the time interval between measurements, $f(t)$ is the nonlinear quadratic vector, and q is the quadratic constants.

3) Measurements: Measurements consist of voltages, currents, and other physical quantities. The measurement model, $h(x)$ expresses the specific measurement as a function of the system states, x, in the following generic form:

$$z_k = c_k + \sum_i a_{k,i} \cdot x_i + \sum_{i,j} b_{k,i,j} \cdot x_i \cdot x_j + \eta_k \tag{2}$$

Fig. 4. Distribution line physical model.

where z_k is the measured value, c_k is the constant term, $a_{k,i}$ are the linear coefficients, $b_{k,i}$ are the nonlinear coefficients, andη_k is the measurement error term. The measurement model is obtained from the generic model equations. As an example the model for a current measurement is simply one of the equations appearing in the set of equations for a device.

Measurements can be also virtual, for example a quantity with a known value. Virtual measurements include Kirchhoff's current law, and other physical laws. In addition, pseudomeasurements can be added to the measurement set. The latter are quantities that their approximate value may be known. Pseudo measurements may include neutral/shield wire current, neutral-to-ground voltage, and so on [3]–[5].

B. State Estimation Algorithm

The state estimation is based on the weighted least squares approach. The objective function can be described as

$$\text{Minimize } J(x) = [z - h(x)]^T W [z - h(x)] \tag{3}$$

where W is the diagonal matrix whose nonzero entries are the inverse of the variance of the measurement errors. The solution is obtained from:

$$\hat{x}^{j+1} = \hat{x}^j + (H^T W H)^{-1} H^T W (z - h(\hat{x}^j)) \tag{4}$$

where $\hat{x}$ is the best estimate of states, and H is the Jacobian matrix of the measurement model, $h(x)$.

C. State Estimation Validation

The chi-square test quantifies the model's goodness of fit to the measurement data by defining the probability that the distribution of the measurement errors are within the expected bounds. Consequently, the confidence level refers to the probability

$$\Pr[\chi^2 \geq \zeta] = 1.0 - \Pr[\chi^2 \leq \zeta] = 1.0 - \Pr(\zeta, v) \tag{5}$$

where ν is the degree of freedom, ζ is the chi-square critical value, and both can be obtained by

$$\nu = m - n, \quad \zeta = \sum_{i-1}^{m} \left(\frac{h_i(\hat{x}) - z_i}{\sigma_i} \right)^2 \tag{6}$$

where m is the number of measurements, n is the number of states, and $\hat{x}$ is the best estimate of states.

If the confidence level is allowable, the accuracy of solution is computed using the covariance (or information) matrix

$$C_x = E[(\hat{x} - \bar{x})(\hat{x} - \bar{x})^T] = (H^T W H)^{-1} \tag{7}$$

where $\bar{x}$ represents the true but unknown state values, and $\hat{x}$ is the estimated value.

The standard deviation of each state is calculated as

$$\sigma_{x_i} = \sqrt{C_x(i, i)} \tag{8}$$

where $C_x(i, i)$ is the ith diagonal entry of the C_x.

The estimates of measurements are given by

$$\hat{b} = h(\hat{x}, \hat{y}) \tag{9}$$

The covariance matrix of the estimated measurements is expressed as

$$\text{Cov}(\hat{b}) = H (H^T W H)^{-1} H^T \tag{10}$$

If the chi-square test produces a very low probability, it indicates the existence of bad data. The bad data are identified by hypothesis testing and rejected from the measurement set. Because the state estimation is applied only to a small section of the system using redundant data, the process is quite efficient.

D. Autonomous Operation Procedure

Fig. 5 describes the flow chart of the autonomous state estimation in the smart grid. It begins with the collection of three sets of data: connectivity, device model, and measurements. Next, states are automatically identified, measurement models, $h(x)$, are constructed, and the state estimation is executed. Bad data detection, identification, and rejection follows. The estimated state is utilized in the smart grid applications. The process is performed continuously at user selected time steps (for example, 10 times per second) and the state estimates are packed into a set of streaming data. Controls are exercised only whenever application dictates it.

E. Scalability

The proposed autonomous state estimator is scalable to any size system. Note that the state estimation is implemented at the concentrator with measurements and device models of a specific

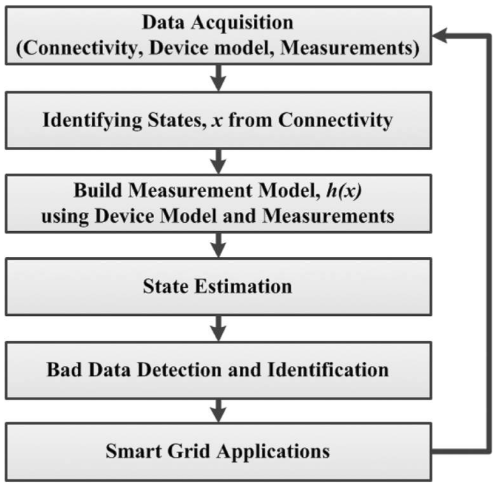

Fig. 5. Autonomous state estimation procedure.

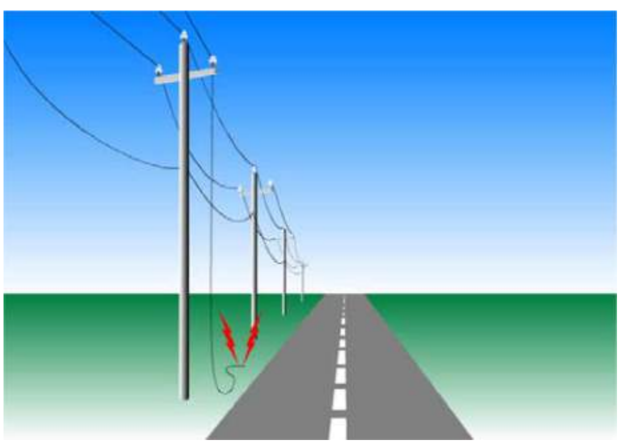

Fig. 6. A downed energized phase conductor.

small part of the feeder. The estimated states are collected in the ADMS where the whole system state is synthesized and used to monitor the real-time operating conditions of the entire distribution system. As a result, the localized state estimation prevents the communication overload as well as computation deterioration. The distributed approach, ultimately, can achieve the goal to expand the proposed infrastructure regardless of the system size and without performance drop.

VI. Smart Grid Technologies

A. Downed Conductor Protection

The proposed infrastructure is the enabler to solve a distribution protection problem for which we presently do not have acceptable solutions and result in numerous fatalities each year. The problem is that of an open conductor. Occasionally, a phase conductor breaks and falls on the ground without making contact with the neutral conductor, as it is illustrated in Fig. 6. In general the contact impedance of a downed phase conductor with the ground (soil) is relatively high resulting in fault currents that may be below load currents. In this case a downed conductor remains on the ground energized until someone interrupts the circuit or an accident may happen.

Efforts to identify these conditions and interrupt the circuit resulted in systems that are either prohibitively expensive or not 100% reliable. In the early 90s the authors developed a special relay that will detect a downed conductor [6]. The relay was relying on communications via the neutral and therefore its proper operation required that the neutral is intact, a reasonable assumption. In evaluating the technology [6] the authors recognized that the deployment of this technology as a dedicated system with the only function of detecting downed conductors is prohibitively expensive and suggested that distribution automation may provide a better approach. Smart grid activities have superseded distribution automation. In particular the proposed smart grid infrastructure can provide an excellent full proof (100%) solution to this unsolved protection problem. This is accomplished as follows. The proposed infrastructure provides frequent updates of the state of the system. Therefore, the electric current flow and voltage is computed at each node of the system. When a downed conductor occurs the voltage on the source side of the conductor will be still high while the electric current will be relatively small. On the other side of the downed conductor the electric current will be practically zero and the voltage abnormal (in general small). Note that the state estimation will identify this condition and it will explain the measurements as a discontinuity on the phase conductor. It will also identify the phase (or phases in case there is the unusual case of multi-down-conductors). The proposed state estimation will also provide the confidence level by which this condition is identified. Once the condition is identified the proper control will be generated to trip the nearest upstream protective device.

B. Load Levelization

The proposed infrastructure is the enabler to effectively achieve levelization of the distribution system electric load without incurring inconveniences to the customers. Load levelization is crucial because of the high ratio of peak load to base load that results in higher design costs (need for more capacity) and higher operating costs (fuel). Load levelization also minimizes losses since energy losses of the transmission lines are greater during peak as well. By properly stating the optimization problem the combined load minimization and loss minimization can be achieved.

In order to achieve load levelization (and therefore peak load reduction), we propose a coordinated control scheme with the participation of several technologies including energy storage systems [7], [8], PHEVs, large energy consumption appliances etc. Their operation has to be optimally scheduled throughout the day in order to reduce the peak load but on the same time avoid customer dissatisfaction. The high fidelity monitoring system we propose can provide continuous and accurate information of the distribution system status and operating conditions. Based on this information the levelization of the distribution system load can be treated as an optimization problem that will exercise the direct load and resource control. Since the load of the distribution system has some statistical characteristics and will change over the time, we divide the time period (one day) into n small time intervals as $t_1, t_2, \ldots, t_n$ and we assume that the load will not change during each time

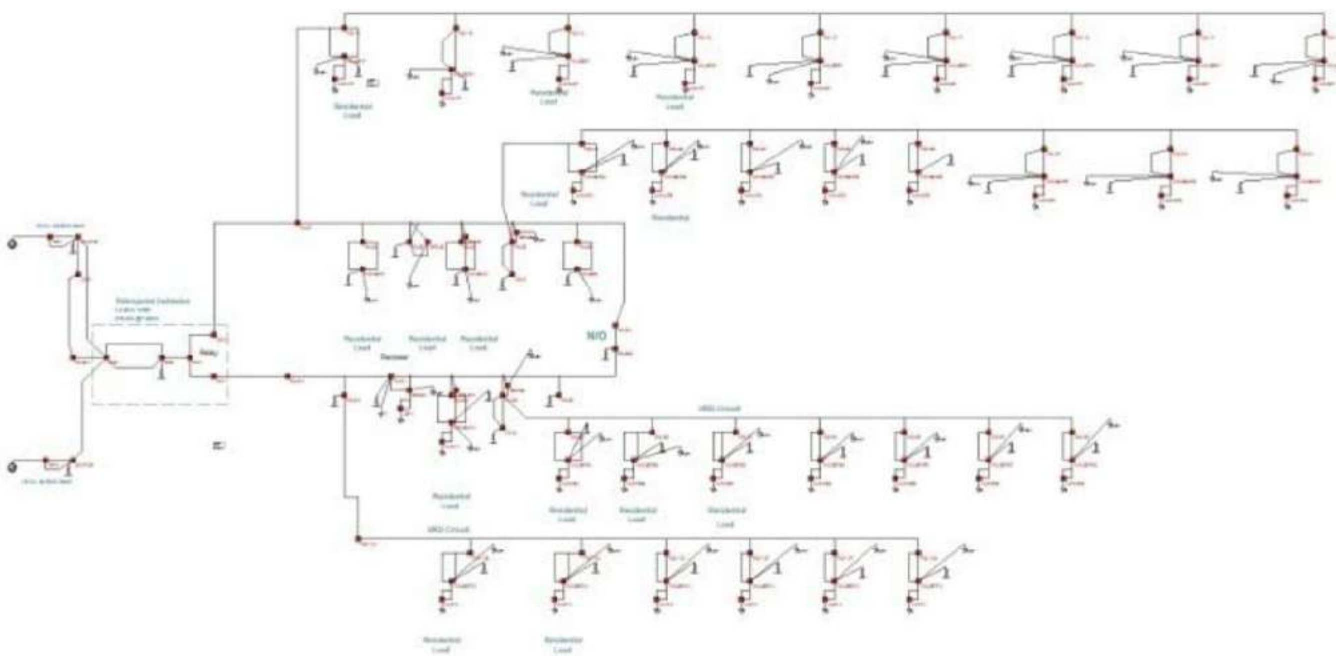

Fig. 7. Distribution system with PHEVs and storage system.

interval. Based on these, the optimization problem can be formulated as follows:

$$
\begin{aligned}
&\min X^* \\
&\quad X^* > \mathrm{Re}(\tilde{V}_1(t_1)\cdot \tilde{I}_1^*(t_1)) \\
&\quad\quad \vdots \\
&\quad X^* > \mathrm{Re}(\tilde{V}_1(t_n)\cdot \tilde{I}_1^*(t_n)) \\
&\mathrm{s.t}\, g(x(t_1),u(t_1),L(t_1)) = 0 \\
&\quad\quad \vdots \\
&\quad g(x(t_n),u(t_n),L(t_n)) = 0 \\
&\quad h(x,u) \geq 0 : \text{Functional Constraints} \\
&\quad u_{i,\min} \leq u_i \leq u_{i,\max} : \text{Control constraints.}
\end{aligned} \tag{11}
$$

Our goal is to minimize the peak load, so the objective is to minimize the maximum value of the loads of the distribution system over all the time intervals. The constraint equations

$$g(x(t_k),u(t_k),L(t_k)) = 0, \quad k = 1,2,\cdots n \tag{12}$$

represent the power flow equations of the distribution system for each time interval and the vectors $x(t_k), u(t_k)$ and $L(t_k)$ represent the state variables, control variables, and the statistical load variables of the distribution system respectively. Additional constraints have to be added that include operating constraints for the distribution system but also for the controllable devices such as the energy in the storage system, the status of smart appliances, etc.

Note that the solution of the above optimization problem provides the required controls to levelize the load for each available load and resource in the system. This approach is different and more advantageous compared to common approaches where price signals are sent to customers and is expected that the customers will respond to these price signals. The price signals are known to generate unwanted responses such as shifting of peaks instead of levelizing the electric load.

A three-phase 13.8 kV, 2 feeder distribution system is developed to demonstrate this application. It is assumed that the distribution system has 30% penetration of PHEVs into current vehicle fleets and 10% penetration of renewable generation. Storage devices are also modeled to store the energy generated by the renewable. The optimization algorithm generates control signals every 15 min to implement the direct load control of the charging time of the PHEVs and the time for the storage system to provide energy to this system. Fig. 8 shows the simulated load profile of the distribution system without and with optimization control for 24 h. From the results, it is obvious that the optimization algorithm delays the charging time of the PHEVs from peak hours to midnight and makes usage of the storage system during the peak hours to achieve a peak load reduction by 30% while sustaining the total energy consumption the same.

C. Loss Minimization

In order to operate the distribution system with minimized losses while maintaining its safe operation, a real-time and coordinated Volt/Var control scheme has to be exercised continuously with the participation of distributed generation resources that will be coordinated with the existing infrastructure such as capacitor banks, distributed resources such as rooftop PVs, wind, etc. This is feasible based on existing technology since DGs are connected to the grid via inverters which have 4 quadrant operation capabilities, thus having the capability to absorb or inject reactive power and participate in a coordinated Volt/Var control scheme, resulting in losses minimization.

The proposed infrastructure is the enabler to effectively minimize distribution system losses in a manner transparent to the end user. The described autonomous three-phase state estimation algorithm is performed multiple times per second based on

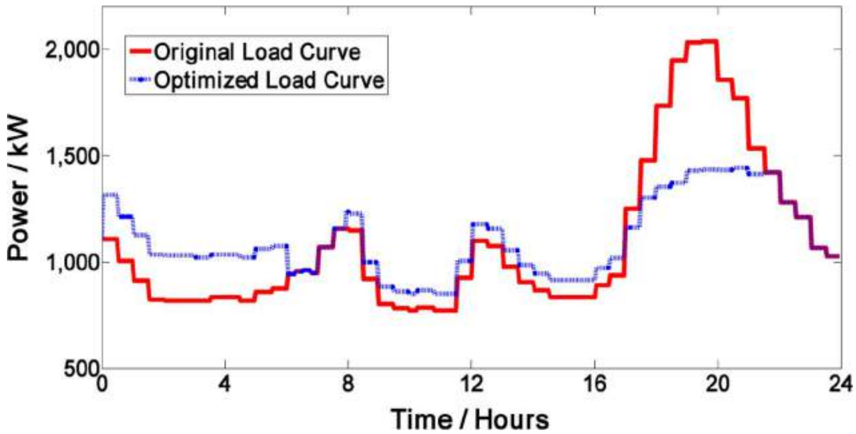

Fig. 8. Load profile of distribution system with/without optimization control.

GPS synchronized measurement data obtained from the UG-PSSMs and nonsynchronized meters available from house meters and SCADA systems. This enables a highly accurate real-time monitoring of the feeders. The importance of the three-phase formulation, as explained before, is more unequivocal in this application, since a significant amount of the losses result from system imbalances and asymmetries that cannot be captured using conventional state estimation approaches based on single-phase, positive sequence equivalents.

Volt/Var control can be exercised via an optimization algorithm that will have as an input the results of the state estimation (system states), with the objective being the minimization of losses. The problem can be formulated as an optimal power flow problem. Its generic formulation is as follows:

$$\begin{aligned} &\min f(x) : \text{Total Losses} \\ &\text{s.t } g(x,u) = 0 : \text{Power Flow Equations} \\ &h(x,u) \geq 0 : \text{Functional Constraints} \\ &u_{i,\min} \leq u_1 \leq u_{i,\max} : \text{Control constraints} \end{aligned} \quad (13)$$

where x are the state variables, and u the control variables.

Total losses can be expressed in terms of the system states, i.e., the node voltages as follows:

$$f(x) = \sum_{\text{circuit}} \sum_{\text{phase}} \text{Re}\{(\tilde{V}_{i,\text{phase}} \cdot \tilde{I}^*_{i,\text{phase}} + \tilde{V}_{j,\text{phase}} \cdot \tilde{I}^*_{j,\text{phase}})\} \quad (14)$$

where i, j: the bus indices where each circuit is connected.

The power flow equations can be expressed based on the quadratic power flow formulation as described in [15]. Functional constraints include limitations such as voltage magnitude or phase angle limits of buses. Finally control constraints refer to distributed resources operating constraints (PVs, PHEVs, storage devices) such as power factor variation limits, active power capability or energy storage limits.

The proposed Volt/Var control scheme was implemented on a base case test system which models a realistic distribution system, including overhead distribution lines, underground cables, single-phase and three-phase transformers, residential, and industrial load. Specifically the base case test system is a 13.8 kV distribution system which consists of a 7.5 MVA distribution substation feeding two main distribution feeders. In each feeder, two laterals are also included. The base case test system is illustrated in Fig. 9. A 15% DG integration was assumed (1.125 MW). The losses before and after the proposed scheme have been computed. Specifically, for the system of Fig. 9, the total loss in a distribution system is 200.309 kW when no loss minimization is exercised and it is 140.19 kW when the proposed loss minimization is applied. Note that a 30% loss reduction has been achieved.

D. *Reliability Enhancement*

Another application of the proposed infrastructure is to improve the reliability of the distribution system. Since the proposed scheme provides the real-time of the distribution feeder, it can identify the fault location with high fidelity and it is relatively easy to optimize the reliability of the system in real time, i.e., to respond extremely fast. Specifically, based on the given condition such as the location of the fault, the status of the switches and breakers in the system, one can determine the optimal configuration of the system in order to isolate the fault to the smallest area and to restore power to as many customers as possible. At the same time, crews can be dispatched to the specific faulted circuit for quick repair and restoration. We will refer to this problem as reliability enhancement. The formulation of the problem is described below. Specifically the optimal reconfiguration problem following a fault is given by

$$\begin{aligned} &\max \sum_{k \in \Omega} S_{Lk} \\ &\text{s.t.} F(V, P_G, Q_G) = 0 \\ &V_k^{\min} \leq V_k \leq V_k^{\max} \\ &P_{Gk}^{\min} \leq P_{Gk} \leq P_{Gk}^{\max} \\ &Q_{Gk}^{\min} \leq Q_{Gk} \leq Q_{Gk}^{\max} \\ &|I_{ij}| \leq I_{ij}^{\max}, ij \in \Omega \end{aligned} \quad (15)$$

where

F power flow function in the affected area;

S_{Lk} load at bus k;

V_k voltage magnitude at bus k;

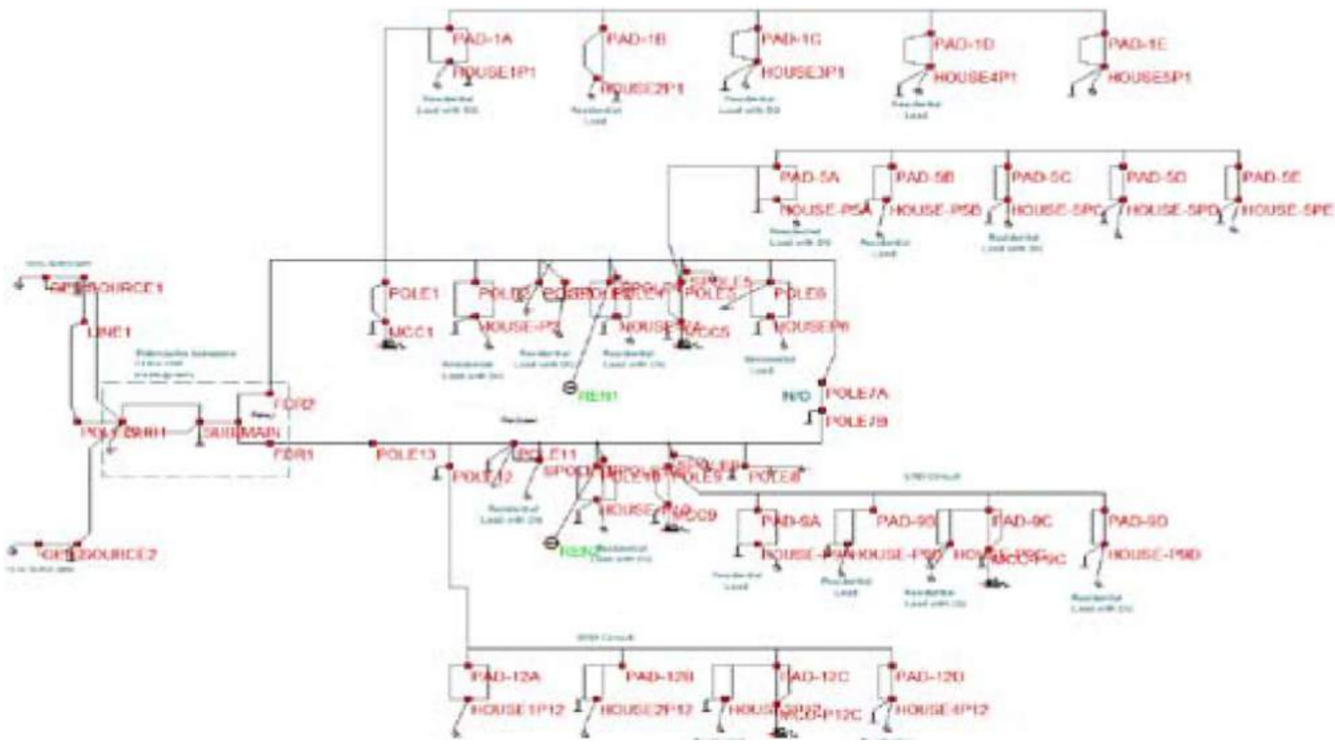

Fig. 9. Losses minimization test system.

$\mathrm{P_{Gk}}$ active power generation at bus k;

$\mathrm{Q_{Gk}}$ is the reactive power generation at bus k;

$\mathrm{I_{ij}}$ current flowing between bus i and bus j;

Ω set of buses in the affected area.

As it is shown above, the objective of this optimization problem is to maximize the total loads that can be connected to the grid in the affected area, improving reliability of the grid as much as possible. The constraints of the problem are the power flow equations and the operating constraints: a) bus voltage regulation; b) limitations of the active and reactive power output of available generators (including DGs) in the affected area; and c) circuit loading constraints. The solution can provide us the detailed information of loads that the grid is able to continue to supply in the event of a fault at a specific location and what will be the optimal sequence of reconfiguration of the feeder.

A three-phase 13.8 kV, 3 feeder distribution system is developed to demonstrate this application. The system is similar to the one shown in Fig. 9. It is assumed that all types of switches in the system are integrated in the proposed smart grid infrastructure and can be automatically operated. For this system results show that the proposed infrastructure can easily achieve 15 to 20% improvements in the basic distribution system reliability indices.

VII. Testing, Verification, and Cybersecurity

New smart grid technologies must be tested and verified to ensure performance. The new technologies are heavily dependent upon GPS synchronized measurements, data validation, communications, and user interfaces. For these systems, cybersecurity has become critically important as the networks become more integrated. A testing program is necessary to ensure that performance meets expectations and cyber vulnerabilities are minimized.

The use of a highly accurate GPS synchronized measurements brings huge computational benefits to the state estimation. A set of tests is required to evaluate the interoperability of the global positioning system with PMU applications, and to test the performance of PMUs with respect to synchronization accuracy and reliability. When a typical GPS-based clock looses satellite tracking it switches into "HOLDOVER" mode. In this mode, GPS accuracy may be lost with catastrophic results to the state estimation performance. A software product was developed that tracks the performance of PMUs in terms of navigation mode and holdover performance. The software product is installed to monitor a specific PMU under field conditions and to record the historical performance of the PMU. The product guarantees GPS accuracy in HOLDOVER mode for at least 8 min. Since clock synchronization is typically lost for seconds, this approach results in no disruptions to the reliability of the state estimation process.

In most cases, PMUs, relays with PMU capability, FDRs, etc., from different vendors are deployed in the same substation. This approach provides redundancy that is extremely beneficial to the performance of the state estimation. The multivendor environment creates the requirement that devices from different vendors should be able to exchange information, do expected work in the network, or sometimes over a network. IEEE Standard 37.118 and IEC 61850 provide the necessary standardization for interoperability among PMUs and other IEDs. For example, both TCP and UDP can be used for the data transmission. The degree to which IEDs comply with these standards must be tested. Interoperability tests have been performed at the Georgia Tech for several devices. These tests showed that several tested devices had problems with supporting the standards. Test results were provided to the manufacturers who in turn made the appropriate modifications. The experience indicates that there is still a lot of work to reach a point where all devices meet the standards and the integration of these technologies can be seamlessly achieved.

With integrated communication networks, the possible threat of cyberattack has become a major issue. Securing the smart grid is very difficult and complicated. There is no a simple and secure method of solving such a complex issue, but there are various elements that can be put together to build a secure system. Cybersecurity must address many issues that might be resulted from deliberate attacks or inadvertent user errors.

VIII. Conclusion

This paper described a comprehensive approach for a smart grid implementation on a distribution system. The basic objective is that the infrastructure should enable all the desirable functions of optimizing the operation of the distribution feeder for maximum benefit to utilities and customers alike. These goals are achievable only via a system that will enable accurate and frequent monitoring of the distribution system. The monitoring function extends to the customer and includes monitoring and control of customer resources. A requirement placed on the proposed infrastructure is that the customer should not be inconvenienced. The proposed scheme achieves the goals of the smart grid with minimal or no inconvenience to the customer. Implementation of the proposed scheme will require the development of low cost meters that will have the capabilities described in the UGPSSM. Currently technology exists to massively manufacture these meters at very low cost.

References

[1] "Communication networks and systems in substations," IEC 61850,1st ed. 2003.

[2] S. Choi, B. Kim, G. J. Cokkinides, and A. P. S. Meliopoulos, "Autonomous state estimation for the smart grid—Laboratory implementation," in *IEEE PES Transm. Distrib. Conf.*, New Orleans, LA, 2010, pp. 1–8.

[3] A. P. S. Meliopoulos, G. J. Cokkinides, F. Galvan, B. Fardanesh, and P. Myrda, "Delivering accurate and timely data to all," *IEEE Power Energy Mag.*, vol. 5, no. 3, pp. 74–86, 2007.

[4] A. P. S. Meliopoulos, G. J. Cokkinides, F. Galvan, and B. Fardanesh, "Distributed state estimator advances and demonstration," presented at the 41st Ann. Hawaii Int. Conf. Syst. Sci., 2008.

[5] A. P. S. Meliopoulos, G. Cokkinides, G. Stefopoulos, T. Conrad, and C. Hedrington, "Distributed state estimator via the supercalibrator approach," *Protection, Autom., Control World*, pp. 38–44, 2009 [Online]. Available: http://www.pacw.org/issue/autumn_2009_issue/state_estimation/the_colombian_blackout/complete_article/1.html

[6] A. Westrom, A. P. S. Meliopoulos, G. J. Cokkinides, and A. H. Ayoub, "Open conductor detector system," *IEEE Trans. Power Del.*, vol. 7, no. 3, pp. 1643–1651, Jul. 1992.

[7] I. Papic, "Simulation model for discharging a lead-acid battery energy storage system for load leveling," *IEEE Trans. Energy Conv.*, vol. 21, no. 2, pp. 608–615, Jun. 2006.

[8] C. Venu, Y. Riffonneau, S. Bacha, and Y. Baghzouz, "Battery storage system sizing in distribution feeders with distributed photovoltaic systems," presented at the IEEE PowerTech Conf., Bucharest, Romania, 2009.

[9] A. P. Sakis Meliopoulos and F. Zhang, "Multiphase power flow and state estimation for power distribution systems," *IEEE Trans. Power Syst.*, vol. 11, no. 2, pp. 939–946, May 1996.

[10] B. Fardanesh, S. Zelingher, A. P. Sakis Meliopoulos, G. Cokkinides, and J. Ingleson, "Multifunctional synchronized measurement network," *IEEE Comput. Appl. Power*, vol. 11, no. 1, pp. 26–30, Jan. 1998.

[11] *IEEE Standard for Synchrophasors for Power Systems*, Std. C37.118-2005, IEEE Power Eng. Soc..

[12] Y. Mao and K. N. Miu, "Switch placement to improve system reliability for radial distribution systems with distributed generation," *IEEE Trans. Power Syst.*, vol. 18, no. 4, pp. 1346–1352, Nov. 2003.

[13] A. P. S. Meliopoulos and G. K. Stefopoulos, "Characterization of state estimation biases," in *Proc. 2004 Int. Conf. Probab. Methods Appl. Power Syst.*, Ames, IA, Sep. 12–16, 2004, pp. 600–607.

[14] A. P. Sakis Meliopoulos, "State estimation for mega RTOs," presented at the 2002 IEEE Power Eng. Soc. Winter Meet., New York, Jan. 27–31, 2002.

[15] A. P. Sakis Meliopoulos, S. W. Kang, G. J. Cokkinides, and R. Dougal, "Animation and visualization of spot prices via quadratized power flow analysis," presented at the Proc. 36th Hawaii Int. Conf. Syst. Sci. (HICSS), 2003.

[16] K. M. Rogers, R. Klump, H. Khurana, and T. J. Overbye, "An authenticated control framework for distributed voltage support on the smart grid," *IEEE Trans. Smart Grid*, vol. 1, no. 1, pp. 40–47, Jun. 2010.

[17] F. Li, W. Qiao, H. Sun, H. Wan, and P. Zhang, "Smart transmission grid: Vision and framework," *IEEE Trans. Smart Grid*, vol. 1, no. 2, pp. 168–177, Sep. 2010.

[18] R. E. Brown, "Impact of smart grid on distribution system design," presented at the IEEE Power Energy Soc. Gen. Meet., Pittsburgh, PA, Jul. 2008.

[19] M. Pipattanasomporn, H. Feroze, and S. Rahman, "Multi-agent systems in a distributed smart grid: Design and implementation," presented at the IEEE Power Syst. Conf. Expo., Seattle, WA, 2009.

[20] A. Ipakchi, "Smart grid of the future with large scale DR/DER penetration," presented at the IEEE Power Syst. Conf. Expo., Seattle, WA, 2009.

[21] A. Chuang and M. McGranaghan, "Functions of a local controller to coordinate distributed resources in a smart grid," presented at the IEEE Power Energy Soc. Gen. Meet., Pittsburgh, PA, Jul. 2008.

[22] V. K. Sood, D. Fischer, J. M. Eklund, and T. Brown, "Developing a communication infrastructure for the smart grid," presented at the IEEE Elect. Power Energy Conf. (EPEC), Montreal, QC, Canada, 2009.

[23] D. G. Hart, "Using AMI to realize the smart grid," presented at the IEEE Power Energy Soc. Gen. Meet., Pittsburgh, PA, Jul. 2008.

A. P. Sakis Meliopoulos (M'76–SM'83–F'93) was born in Katerini, Greece, in 1949. He received the M.E. and E.E. diploma from the National Technical University of Athens, Greece, in 1972, the M.S.E.E. and Ph.D. degrees from the Georgia Institute of Technology, Atlanta, in 1974 and 1976, respectively.

In 1971, he worked for Western Electric, Atlanta. In 1976, he joined the Faculty of Electrical Engineering, Georgia Institute of Technology, where he is currently a professor. He is active in teaching and research in the general areas of modeling, analysis, and control of power systems. He has made significant contributions to power system grounding, harmonics, and reliability assessment of power systems. He is the author of the books *Power Systems Grounding and Transients* (Marcel Dekker, 1988), *Lightning and Overvoltage Protection, Section 27, Standard Handbook for Electrical Engineers* (McGraw-Hill, 1993) and the monograph *Numerical Solution Methods of Algebraic Equations* (EPRI monograph series).

Dr. Meliopoulos is a member of the Hellenic Society of Professional Engineering and Sigma Xi.

George Cokkinides (M'85) was born in Athens, Greece, in 1955. He received the B.S., M.S., and Ph.D. degrees at the Georgia Institute of Technology, Atlanta, in 1978, 1980, and 1985, respectively.

From 1983 to 1985, he was a Research Engineer at the Georgia Tech Research Institute. Since 1985, he has been with the University of South Carolina, Columbia, where he is currently an Associate Professor of Electrical Engineering. His research interests include power system modeling and simulation, power electronics applications, power system harmonics, and measurement instrumentation.

Dr. Cokkinides is a member of the IEEE Power Engineering Society.

Renke Huang (S'09) was born in Wenzhou, China, in 1984. He received the B.S. degree in electric power system and automation from the Shanghai Jiao Tong University, China, in 2006 and the M.S. degree in Electrical and Computer Engineering from the Georgia Institute of Technology, Atlanta, in 2009. He is currently working toward the Ph.D. degree in the School of Electrical and Computer Engineering of Georgia Institute of Technology, Atlanta.

His research interests include power systems automation, control, and the application of digital signal processing technologies in the power system area.

Evangelos Farantatos (S'06) was born in Athens, Greece, in 1983. He received the Diploma degree in electrical and computer engineering from the National Technical University of Athens, in 2006 and the M.S. degree in electrical and computer engineering from the Georgia Institute of Technology, Atlanta, in 2009. He is currently working toward the Ph.D. degree in the School of Electrical and Computer Engineering, Georgia Institute of Technology.

In summer 2009, he was an intern in Midwest ISO, in the market operations department and especially in the FTR group. His research interests include power systems state estimation, protection, control, and smart grid technologies.

Sungyun Choi (S'09) received the B.E. degree in electrical engineering from Korea University, Seoul, in 2002 and the M.S.E.E. degree at Georgia Institute of Technology, Atlanta, in 2009. He is currently working toward the Ph.D. degree in the Power System Control and Automation Laboratory at Georgia Institute Technology.

He worked as a network and system engineer in Korea. His research interest lies in distributed power system automation and control, power system protection, communication networks, and systems in substation automation.

Yonghee Lee (S'10) was born in Seoul, Korea, in 1982. He received the B.S.E.E. degree from Yonsei University, Korea, in 2007. He started his graduate studies in from 2008 fall semester. He is now working toward the M.S./Ph.D. degree at the Georgia Institute of Technology, Atlanta, under the advisory of Prof A. P. Meliopoulos.

His research interests include PMU device testing, system estimation (static, dynamic), power system control using smart grid concept, and distribution line protection.

Xuebei Yu (S'10) was born in Ningbo, China, in 1986. She received the B.S. degree in electric power systems and automation from Zhejiang University, China, in 2009. She is now working toward the M.S. degree under the advisory of Prof A. P. Meliopoulos at the School of Electrical and Computer Engineering of Georgia Institute of Technology, Atlanta.

Her research interests include power systems automation, reliability analysis, and smart grid technologies.