A Deployment Strategy for the Smart Grid: From the Generator to the Refrigerator

WHITE PAPER

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The electric utility industry will not meet tomorrow's challenges by using yesterday's ideas. The price of electricity is rising. Our customer's and regulator's expectations are constantly changing. Everything we know tells us that we must challenge ourselves to be better stewards of our finite natural resources — clean air, water and land — that have made the western world great and offer the hope of a longer, healthier and more prosperous life.

Where do we start? Thomas Friedman in his best selling book, "Hot, Flat and Crowded: Why We Need a Green Revolution — and How it Can Renew America," tells us that there is no easy way. Friedman contends that the technology exists to fundamentally change the way we use energy, but it is politically trapped by yesterday's fossil fuel-centric culture and economy. Tremendous political leadership is required to forge change and to meet the challenge of providing the basic need of affordable, clean energy for a heavily populated planet.

Interestingly, Friedman and many others believe that the electric utility industry can have a fundamental role in meeting this challenge by implementing a smarter electric grid. But change does not come easily for the electric utility industry. Political preferences and regulatory policies vary from state to state and region to region, impacting everything from public perception to investor/member confidence. So how will the electric utility industry implement a smarter electric grid? Will regulators allow recovery of prudent investment, and how will recovery of lost sales be handled? This white paper explores a deployment strategy for the Smart Grid for electric utilities small and large, for utilities with 5,000 customers or 500,000. We will start by defining the Smart Grid and progress through 12 strategies that, when deployed in a systematic approach, will deliver the foundation upon which we can build a smarter electric grid from the generator to the refrigerator.

DEFINING THE SMART GRID

The Smart Grid is the convergence of information technology (IT) and operational technology applied to the electric grid, allowing sustainable options to customers and improved security, reliability and efficiency to electric utilities. The Smart Grid can be applied to generation, transmission, distribution, metering and, perhaps most importantly, beyond the meter to customer facilities. Distributed generation (DG) and the dispatch and storage of renewables, transmission line loading and substation equipment monitoring, distribution power flows and voltage measurement, automated meter reading and many other benefits all hold promise.

If the Smart Grid is to be ultimately successful in meeting the aforementioned challenges, it must first be deployed on the electric distribution grid in a manner that specifically addresses customer needs. The electric utility industry must prioritize what areas of focus provide the highest value to the customer. We must avoid building "the world's most expensive meter reading system." Therefore, deploying the Smart Grid on the electric distribution grid will require a coordinated, prioritized and customer-based focus in the following strategic areas:

1. Program management
2. Business analysis
3. Demand-side management (DSM)
    a. Telecommunications and network engineering
    b. North American Electric Reliability Corp. (NERC) standards compliance
4. Data acquisition technologies

5. Distributed generation (DG)
6. Home Area Networks (HANs)
7. Data integration management
8. Data analytics and evaluation
9. Remote equipment monitoring
10. Energy efficiency and management

1. PROGRAM MANAGEMENT

Program management *defines and delivers a multifaceted contracting and implementation strategy for large-scale, multiyear projects.*

Program management for the build-out of a Smart Grid delivers thought leadership, a project execution plan and potentially incorporates dozens of subcontracts. Thought leadership starts with the definition of the Smart Grid and an explanation of the array of technologies, applications and government incentives available for consideration. The program manager works to establish a benchmark of current performance metrics and sets future goals for performance by meeting with stakeholders including various customer classes, employees (regulatory and ratemaking staff, engineers, operators and planners), regulators, investors and special interest groups. The gap between current performance and desired performance helps set priorities for and drive Smart Grid initiatives while providing a higher level stakeholder acceptance through participation in the process. It will be important to learn what each customer class wants and what each will accept. Affluent residential, limited income residential, early adopter residential, environmentally sensitive residential, small commercial, large commercial, industrial … there is no universal customer. In the era of intense cost pressures on electric utilities and rising costs for customers, a heavy emphasis must be placed on the residential customer that ultimately will be the voter in the next election. The Smart Grid without smart customers will be a failure.

A project execution plan (PEP) is a living document that guides the project team with a strategic and systematic approach to building the Smart Grid over the course of the program. Based on the input from stakeholders, the PEP introduces a step-by-step process for the study, pilot and implementation phase and performance measurement of each technology to be deployed. It addresses the specific type and anticipated volume of data required to generate useful information, and it outlines how that information will be applied to the electric grid, allowing sustainable options to customers and improved security, reliability and efficiency to the electric utility. The PEP addresses how each component of Smart Grid deployment will act as part of a greater system to achieve the performance goals established by the stakeholders. Critical analysis of the short- and long-term ramifications of technology deployments and the impact on IT and operating systems is key.

The program manager is responsible for establishing budgets and schedules for the study, pilot and implementation phases of the Smart Grid deployment. Budgets include hard cost estimates of the phases, government incentives, if any, as well as management expenses. Schedules should be built around outage windows, material availability, contractor input and customer convenience using Primavera P6 or a similar project management software system. Documentation of the stakeholder input and the overall decision-making process is achieved by using Contract Management software by Primavera. In addition, Contract Management tracks all contracts, vendor correspondence, invoices and payments through the life of the program and creates an outstanding long-term record for internal and external auditors (regulators).

Step 1.1:	Meet stakeholders and define the Smart Grid.
Step 1.2:	Perform a gap analysis.
Step 1.3:	Write and present a PEP.
Step 1.4:	Document the process through all phases of development.

2. BUSINESS ANALYSIS

***Business analysis** develops the business case for the Smart Grid and supports regulatory strategy.*

The PEP provides a step-by-step process for the study, pilot and implementation phase of each Smart Grid technology to be deployed. A business case evaluating the cost versus the benefits of each technology must be performed and may address technologies that may qualify for state or federal government stimulus funds, incentives or tax credits. Some new Smart Grid equipment and technologies may reach obsolescence more rapidly than older generations of assets. The business case analysis and certainly an application for U.S. Department of Energy (DOE) stimulus funds will require a thorough evaluation of costs versus expected benefits of reliability, operational efficiency or ability to handle advanced applications. How much reliability or efficiency a planned project provides is a fundamental question with a difficult answer. A business case should consider potential early retirement of aging assets and a faster rate of depreciation for newly installed Smart Grid technologies. In addition, an analysis should quantify the impact of energy efficiency on total revenue. This will be an important factor to support projected shareholder or member returns on investment. This analysis is less critical in a public power environment, but it should still be conducted. That said, regulatory support of time of use (TOU) or dynamic pricing to meet the DOE's intent for Smart Grid may be challenging to achieve. Early involvement of regulators is critical in the implementation of Smart Grid and the recovery of prudent investments and lost sales revenue.

Step 2.1:	Prepare cost estimates from the gap analysis.
Step 2.2:	Consider application for Smart Grid investment grants.
Step 2.3:	Present to management and regulators for approval and rate recovery.
Step 2.4:	Agree with regulators on rate structures and cost recovery mechanisms for lost kilowatt-hour sales.

3. DEMAND-SIDE MANAGEMENT

***Demand-side management (DSM)** studies the rate impacts of conservation and other demand-response (DR) programs.*

The future of electricity begins with the customer. Integration and management of system and customer data can lead to the ability to analyze warehoused information in a manner that improves operational efficiency and reliability, but most importantly provides sustainable options for customers. Sustainable options will include DR and DSM programs for all customer classes, allowing "prices to devices" supported by ultra-simple rate plans. Data will become information used for action.

DR is a voluntary rate structure that typically lowers a customer's general rate per kilowatt-hour. The utility has the option to curtail power as needed during system peak-loading events. DSM is the effort to incentivize customer usage through simple TOU rates that generally correspond to the cost of producing electricity. DR and DSM shift electric load and improve the electric utility's load factor and should not be confused with energy-efficiency programs that reduce load and, therefore, sales. The current regulatory construct allows investor-owned utilities a reasonable rate of return (profits) on prudent investments and the cost to operate and maintain those investments. Some utilities seek to decouple their sales from profits since energy-efficiency programs lower sales as less electricity is consumed. Decoupling sales and profit theoretically makes the electric utility indifferent to energy-efficiency programs and DG, including plug-in hybrid electric vehicles (PHEVs), but remains a controversial issue in the industry.

The Smart Grid will require a strong marketing program to overcome customer apprehensions and consistently and directly answer questions about DR and DSM. How does it all work together to mitigate rate increases? The marketing program must include:

- A positive, consistent message, repeated often
- A voluntary program with no government mandates for consumers
- Simple programs that are easy to understand and apply
- Promotion of the sustainability of the options and how use of the program improves the environment and the carbon footprint
- Opportunities to respond to the price of electricity

Step 3.1: Develop and market a residential and small commercial (under 200 kW) TOU rate that adequately incentivizes customers to shift load to off-peak periods to promote DSM.

Step 3.2: Develop and market a large commercial TOU rate that makes several load-shifting technologies more economically attractive to customers.

Step 3.3: Develop and market large commercial DR rate that adequately incentivizes customers to curtail load when needed by the utility.

Step 3.4: Develop and market a residential and small commercial net-metering rate that allows customers to sell electricity back into the grid to promote renewable DG.

Step 3.5: Develop and market a residential pay-as-you-go metering program for small residential customers to include the poor, elderly, apartments, vacation homes and customers who aren't interested in adoption of the technology.

Step 3.6: Develop a passive efficiency weatherization program for groups in step 3.5.

3a. TELECOMMUNICATIONS AND NETWORK ENGINEERING

Telecommunications and network engineering *is essential to developing the robust broadband system necessary for the transfer of data from the customer, distribution feeder or substation to operations centers.*

Electric utilities continue to be among the largest users of privately owned and operated wide-area networks (WANs) for communications. These networks include a hybrid mix of technologies, including fiber optics, power line carrier systems, copper wire lines, and a variety of licensed and unlicensed wireless technologies. The utility WAN is designed to support applications vital to the safe and reliable operation of the electric utility's mission-critical infrastructure:

- Protective relaying for high voltage lines
- Supervisory control and data acquisition (SCADA)/energy management systems (EMS)
- Mobile fleet voice and data dispatch
- Generation plant automation
- Distribution feeder automation
- Physical security

Rather than relying on public communication carriers — AT&T, Sprint, Verizon, et al — utilities justify the costs of building and operating their own private WANs because of the highly critical nature of these applications for maintaining a reliable and secure power grid. Less-critical business applications like corporate voice and data networks are also supported but are not normally the driver for private, WAN deployment.

A typical electric utility WAN consists of a high-bandwidth backbone network that backhauls large numbers of channels and applications from the utility service territory to the control center(s). Lower-bandwidth segments, or spurs, connect individual or small groups of facilities to the backbone. Fiber optics and/or digital microwave radio are usually the technologies of choice for backbone transport, whereas the spurs may combine these technologies with less-robust alternatives such as copper twisted-pair wire lines, power line carrier, very high frequency and ultra-high frequency radio links, and unlicensed wireless systems. Common carrier-leased services are used sparingly for low-criticality applications in locations where privately owned alternatives are cost-prohibitive.

These utility WANs have served traditional applications like supervisory controlled and data acquisition (SCADA)/energy management systems (EMS), distribution automation (DA)/DSM and automatic meter reading (AMR) and are now popularly encompassed as part of the Smart Grid. The number of locations requiring communications service increases, and the criticality of each location to the integrity of the overall grid decreases as these applications are pushed deeper into the distribution system (i.e., farther from the primary substation and closer to the customer). Historically, this combination of increasing costs and decreasing benefits has been the primary obstacle to deployment of more feeder-level and customer-level applications such as DA/DSM and AMR/advanced metering infrastructure (AMI). When such applications are deployed, costs are controlled by limiting communications to one-way systems, like broadcast radio signals, or narrow-band, high-latency systems, like power line carrier or dial-up phone lines.

Today, the political and regulatory impetus for wider deployment of Smart Grid applications, especially its deployment all the way to the customer premises, has resulted in pressure on utility engineers to solve the problem of establishing robust data-transport WANs to the distribution feeder and customer level. The proliferation of information technology utilizing Internet protocol (IP) transport over Ethernet has made IP the de facto standard for data transport. What is needed is a nearly ubiquitous IP transport network operating at bandwidths robust enough to handle traditional utility power delivery applications along with vast amounts of new data from the Smart Grid. These networks need to be scalable enough to handle future applications as they come. This is easier said than done.

Communications for Smart Grid data transport require that utilities address both the backbone and the spur segments. Most electric utility communications backbones today are based largely on traditional time-division multiplexing (TDM), digital architectures. TDM technology, while highly reliable, was originally developed for the transport of point-to-point, constant-bit-rate voice communications. It is not necessarily well-suited for cost-effective transport of point-to-multipoint, or "bursty," data traffic required in an IP environment. The Smart Grid will require that these backbones be upgraded to backhaul Ethernet/IP data traffic at speeds ranging from 1 to 10 gigabits per second in a highly reliable manner. Rather than replacing their legacy TDM networks, many utilities will opt initially to overlay these existing networks by overbuilding gigabit Ethernets on unused fiber and licensed or unlicensed broadband wireless networks over existing microwave paths.

The deployment of spur or last-mile communications for the Smart Grid — typically from a backbone node to the customer premises — offers additional challenges. First, the network must cover a very large area, especially if a utility is serving residential customers. This has prompted some utilities to take a phased approach, deploying the Smart Grid to large-load industrial and commercial customers initially because the bulk of the benefits of Smart Grid follow the bulk of the electrical load. Residential applications may remain on the back burner, waiting for a clearer quantification of benefits. This balanced approach may make sense economically, but it may have broad ramifications politically as rates rise and residential customers (voters) demand relief.

Second, the proper balancing of performance and cost is less clear for these last-mile applications. Losing communications with a small percentage of the DA or AMI for a time, while undesirable, would pose no real threat to the safe and reliable operation of the overall power grid. Communications with a single customer or residence does not require the bandwidth and performance needed in the backbone, so low-speed communication devices with marginal signal strength that may require multiple retransmissions to complete a message can be tolerated. These issues raise questions like:

- How reliable is reliable enough?
- How fast is fast enough?
- At what cost?

The determination of the correct cost-performance ratio for last-mile data transport can be elusive, but there may be a silver lining. The relaxed performance and reliability constraints in the last mile also means that there are more technology options available for this portion of the WAN. Technologies like meshed Wi-Fi, packet-based store and forward radio networks, and broadband-over-power line are not considered reliable or robust enough for the mission-critical infrastructure backbone, but these are viable options for the last mile. Likewise, public carrier and cable television-based services like broadband cable modem, digital subscriber line (DSL) and cellular-based wireless data networks may also make sense where utilities can negotiate bulk service rates.

Ultimately, there are several good options for a secure, robust telecommunication network for mission critical and non-mission critical data transport. However, once the DA or AMI data is efficiently transported a whole new set of data integration and management issues will challenge utilities technically and culturally.

Step 3a.1:	Match the telecommunication technology with the specific development strategy or strategies it is designed to serve and at similar reliability levels (system average interruption frequency index, or SAIFI, and system average interruption duration index, or SAIDI) of the existing, surrounding distribution assets and system.

3b. NORTH AMERICAN ELECTRIC RELIABILITY CORP. COMPLIANCE

***North American Electric Reliability Corp. (NERC) compliance** experts should evaluate physical and cyber security requirements and develop compliance plans.*

Operating and maintaining the bulk power system in accordance with the requirements of NERC and the Federal Energy Regulatory Commission (FERC) will be a daunting task for system operators. They will need the technical support of line, substation, protection and control, and telecommunication engineers to maintain compliance. Today, however, there are no specific cyber security standards for the distribution system where much of the Smart Grid will be deployed. The Smart Grid accelerates the need to address cyber security issues and develop comprehensive solutions that can be upgraded rapidly as security needs increase. The DOE encourages the following points for consideration:

- Description of methodologies used to identify cyber security risks and the outputs from those assessments
- Descriptions of how cyber security risks will be addressed at each phase of the engineering life cycle
- Descriptions of how relevant cyber security standards will be utilized at both the technology level and for the management and operations of the technology
- Description of how components (hardware and software) and the installed system will be tested to determine effectiveness of cyber security measures

Step 3b.1: Follow DOE initial considerations for standards development through National Institute of Standards and Technology, for cyber security and for any NERC requirements that may apply.

4. DATA ACQUISITION TECHNOLOGIES

***Data acquisition technologies** allow for the transmission of real-time information that will be necessary for improved security, reliability and operational efficiency.*

Increasing demands on electric power companies to supply reliable power while enabling sustainability efforts require a more robust grid-control system. Data acquisition technologies such as AMI and DA enable utilities to leverage customer behavior and have near instantaneous outage identification and recovery, allowing greater control of the power grid. Reducing outage durations, monitoring and controlling voltage levels (to save load) and reducing consumer peak demand all contribute to grid reliability and sustainability. Enhanced management and control of the grid can lead to lower costs, protected investments and improved customer satisfaction.

An important aspect of the Smart Grid infrastructure is automating and optimizing distribution feeders based on real-time data. Some power utility assets have been in place for more than 50 years. With an aging power system, the need for advanced system monitoring and control increases dramatically. DA allows for real-time monitoring and automated control of power distribution networks. This advanced system must be reliable, secure, sustainable and, most importantly, efficient, allowing utilities to optimize overall system performance.

DA allows for more refined switching of the grid. The system monitors its assets remotely and recovers from potential outages and events. The ability for the grid to proactively manage outage avoidance is a critical need for utilities, so a DA system must be flexible yet robust enough to satisfy this critical function. The grid should be self-healing in its ability to actively transfer load as demand changes and outages are anticipated. The ability to actively monitor load and feeder conditions increases the effective optimization of feeders and transformers. Automation is the key process in expediting fault detection, fault location and, most importantly, service restoration.

The ability for the Smart Grid to minimize outages is derived from the speed at which the grid will be able to actively react to changing load conditions. DA coupled with DG creates micro-grids that transfer loads to specific areas, isolating customers from the affected part of the grid and keeping them in service.

DA can also be coupled with the idea of AMI to proactively control distributed power based on load factors. A tightly integrated communications network of DA and AMI applications delivers improved coverage for both applications, leading to cost options for customers, faster service restoration and generally improved system reliability.

AMI refers to the system that is employed to monitor, control, collect and analyze energy usage data being transferred over the electrical grid. This infrastructure relies on a two-way communication network to exchange data between service providers and their measurement devices (smart meters). This transfer of data allows for dynamic pricing, DR, outage management and general system monitoring. AMI can optimize energy consumption and provide information to determine if there is adequate generation during peak loading.

The infrastructure used in AMI consists of three parts:

- Meter data management, which includes aspects of collection, monitoring and warehousing
- The network, including the physical communication link
- The meters, the source of the aggregated data

Meter data management is a service-provider system that forms the basis of AMI. Managing the data received from smart meters gives utilities the ability to monitor their network and sense grid changes. AMI is an effective way to monitor assets remotely and improve outage response. It also allows providers to monitor feeder loading and ensure it remains within limits of the system to protect the grid from devastating outages. Incentive-based DR and dynamic pricing structures encourage customers to embrace these new technologies while potentially creating sustainable savings for both the utility and its customers. This data enables the customer to automatically manage finances by leveraging TOU rates and decreased usage based on their desired spending profile.

The communication network is the link that connects all aspects of AMI from the provider to the customer and must be secure, robust and reliable. Network standards are being created to ensure AMI communications are consistent across the grid. Depending on the environment where the network is being installed, various technologies exist to bridge the gap between the AMI centralized utility location. Some cyber security concepts avoid a hardwired communication link between the customer and the utility.

The proposed networks include:

- Cell networks
- Licensed radio networks
- Unlicensed radio networks
- Power line carrier communication

These proposed networks have individual advantages and disadvantages, which must be standardized for a uniformly updated grid. Along with the medium of communication comes the type of network that will be implemented. Meshed radio frequency (RF) networks are appropriate for densely packed urban environments. Rural service territories, however, pose a greater challenge because of the distance between meters. Ultimately, a combination of meshed wireless networks and wired networks will be used to link all aspects of AMI and Smart Grid communications.

Smart meters provide an economical way to measure energy consumption on a per-user basis. Smart meters also allow utility companies to manage generation output and reduce peak-energy demand through customer involvement. Utility price signals and data from smart meters to the customer is the final link in AMI. A system of smart meters provides a way for the utility to implement DR techniques and allows the customer to receive dynamic pricing signals. Usage statistics from these meters must be transferred reliably and securely over the communication network to a central location for data integration management and analytics.

Two-way communication enables AMI to provide maximum benefit. Smart meters receive grid information such as rate structures, control meter functions and grid health data. This ability allows the utility to detect fraud on the system, remotely connect and disconnect service from customers, and receive outage restoration notifications. The meters also act as the gateway to the Home Area Network (HAN), where devices inside the house are controlled based on variable rate structures received at the meter from the utility. During peak loading times, the meter can control individual smart devices inside the HAN based on predetermined price structures programmed into the device. Customers can automatically optimize consumption based on pricing structure changes received from the utility. If an unstable grid situation was observed or an outage was projected, the meter could respond to the increased demand by reducing power consumption to improve electrical grid stability. Fundamentally important to successful deployment of AMI is billing format and accuracy. Customers should be notified of meter and rate changes early and often and billing file formats should be specified and strictly observed.

DA and AMI equip a utility to increase automation, increase user interaction, and decrease operating costs and errors. Automation and advanced communications have gone past the distribution substation and provide the groundwork for extending grid intelligence to the end user. These systems will make an intelligent and controllable utility of the future. The binding tie between these systems is a strong communications backbone. Utilities must rethink past operations in order to stay ahead of the ever-increasing load and the future of the grid. Through DA and AMI, utilities gain the ability to be streamlined and efficient in advancing the grid. These technologies will minimize peak loads, minimize outages and, most importantly, increase efficiency through pre-emptive outage avoidance.

Overhead distribution infrastructure serves areas with older, less energy-efficient residential and commercial buildings and structures. Depending on how the service territory has grown over the decades, these also may be limited-income areas. These legacy systems are harder to adapt to new equipment and may require significant capital upgrade to maintain system reliability and deliver Smart Grid attributes. Older equipment is the best candidate to be effectively optimized by monitoring the load and feeder conditions. Therefore, a deployment strategy for the Smart Grid should apply DA to pre-identified electric circuits on older, overhead distribution lines. The upgraded circuits will then operate more efficiently electrically and are sometimes referred to as “green circuits.” Further, older neighborhoods and their surrounding businesses may be better candidates for passive energy-efficiency measures such as weatherization and/or prepaid metering rather than a more active prices-to-devices approach.

Newer circuits in newer service territories are more often underground. These circuits that feed large residential customers and the small commercial businesses that surround them are the best candidates for build out of AMI to test customer programs for net metering and rate structures that encourage load shifting and energy conservation. An AMI pilot should be conducted with the permission and participation of randomly selected customers in these areas. Careful business-case analysis and rate-structure development must be employed with the pilot.

Step 4.1:	Identify potential green circuits in older service areas and apply DA.
Step 4.2:	Conduct an AMI pilot on randomly selected and solicited 1% of large residential and small commercial customers on newer underground circuits.

5. DISTRIBUTED GENERATION

Distributed generation (DG) *involves engineering to integrate renewable and micro-scale resources.*

Two sources of distributed generation make the most sense today — solar energy and PHEVs. Under a Smart Grid topography, distributed sources of generation near load centers will be widely used to relieve the strain on central station power plants and the associated transmission and distribution lines. Customers also will play a more active role in the operation of the electric grid system with control of their own energy use and, should they so choose, control of their own electricity generation assets.

With today’s heavy focus on clean, renewable energy sources and the desire to reduce carbon footprints, solar energy will likely be an energy source of choice for many Smart Grid participants. In addition to its environmentally friendly nature, solar energy technologies, specifically photovoltaic technologies, have other attributes that lend themselves to the Smart Grid enterprise.

Photovoltaic solar systems can be installed in increments, keeping pace with local load growth. Their modular nature also provides flexibility in choosing a site. Rooftop systems require no additional land, and land-based systems are minimally disruptive to property, allowing the utilization of brownfield sites that would otherwise remain useless or require expensive remediation.

The concept of the Smart Grid is based on the proliferation of two-way communication channels between the grid and the loads that it serves and between the grid and the generation sources that feed into it. Indeed, this communication system is an enabling factor for the widespread use of solar and other generation sources with an intermittent nature.

The photovoltaic system inverter is an obvious choice for the communication point with the solar system. Not only can control of the inverter be used to curtail input into the grid if necessary, but phase control of the energy feeding into the grid can be achieved by enabling dynamic volt-ampere reactive power (VAR) control of inputs to the grid, which can help provide stability in the grid voltages.

Net metering is a rate structure for individual customers that own distributed generation or storage and feed power back into the grid when the grid needs it most. Some states allow net-metering at full retail rates, but net meter rates and system safety and reliability issues must be addressed by the utility and its regulators.

Net metering and energy storage will be enabling factors for the Smart Grid, particularly as associated with the widespread use of customer-owned or custom premise solar generating systems. Solar energy remains one of the most expensive sources of electricity. Thus, owners of solar generating systems will benefit from dynamic pricing models that credit their solar power production during peak periods with on-peak/critical peak pricing through net metering. Under certain conditions of minimal load and high solar generation, the grid may decide that reduction or even curtailment of the solar generation is required. This undesirable condition for the solar system owner can possibly be avoided by utilizing energy storage technologies that store the excess energy for use on the grid at another time. The batteries from PHEVs can provide that energy storage component.

The interconnection standards and policies for photovoltaic solar systems and other distributed generating systems connecting to the grid must be streamlined. Renewable energy sources will continue to grow as a source for DG, with PHEVs evaluated as one piece of the puzzle. As more PHEVs hit the roads, the demand these vehicles place on the electric grid may be offset by using them as an energy storage source when needed. The Smart Grid will support the necessary communications infrastructure to allow PHEVs to not only take power from but return power to the grid. The ability of vehicle-to-grid (V2G) systems to provide adequate power has to be calculated and evaluated against the benefits to the utility and the owner of the vehicle.

While not applicable for base load generation, PHEVs may assist with peak power demands and quick-response electric delivery. In most cases this would be during peak load windows of shorter duration, usually from one to four hours. PHEVs identified in a given area, for example, a business park, are plugged into the grid and may be tapped to help offset the electrical demand of the same business park. Several parks or other grouped charging stations can then be aggregated and utilized by the grid controller to provide power for a given area without draining an individual PHEV past its safe or normal battery discharge limit.

For a PHEV to be used as a DG source, the vehicle itself needs to be able to calculate its excess stored power. This calculation will be based on present location, day of the week and other factors that will be transmitted back into the grid via V2G systems. Since the car needs to be able to have enough energy to return home, the remaining charge of the batteries will need to be sufficient to meet that task. These systems work two ways. The first and most common way is to identify the most cost-effective time to charge the vehicles batteries. Normally this will occur at night at the owner’s home, when grid demand is at its lowest. The second scenario will occur when grid demand is approaching or at its peak. The grid will be given access to the vehicle’s battery storage information. The V2G systems and the grid control system will determine whether the vehicle should continue to be charged at that moment or whether it has excess power that can be used by the grid.

The V2G systems will be fully integrated into the vehicle and be able to learn owners’ driving patterns to provide reasonable information to the grid control systems. The converse also needs to be addressed. Grid-to-vehicle systems need to be created and implemented by the utility that enable it to identify a PHEV and correctly bill for the power used in charging and also reimburse the owner for energy used to support the grid. To address the communication needs between the grid and the vehicle, working groups such as Society of Automotive Engineers (SAE) J2836 and SAE J2847 will address charging standards and communication.

Benefits to the utility for using PHEVs as a DG source will vary depending on the number of PHEVs in a given area. As carbon emissions become more tightly monitored, the ability to offset the need for peaking fossil fuel-fired plants could be cost-effective. Additionally, utilizing the PHEV as a spinning reserve would eliminate the need to buy power from another generator, even if the cost per kilowatt-hour was higher, due to emissions penalties and fixed costs paid by the grid operator to have reserves on standby. The utility could create an incentive to the PHEV owner by paying for power returned to the grid. By paying the PHEV owner, the cost to the utility might be lower and the utility might avoid financial penalties for exceeding the carbon cap. Benefits to the PHEV owner are mostly financial. A different rate structure and payments for returning power to the grid may entice the owner to participate in V2G.

PHEVs will have a place in DG going forward. What remain to be determined are the final standards between the vehicle manufacturers and the grid operators, acceptance by public utilities commissions of these systems and consent from PHEV owners. Once these challenges have been met, PHEVs as a DG source could be viewed the same as solar power generation, especially with the battery-storage capability.

Step 5.1:	Develop a solar-photovoltaic-rooftop rebate program for small and large business customers at the penetration rate of 1% of commercial customer base through federal incentives.
Step 5.2:	Install PHEV charging stations for 1% of the large residential and small commercial accounts in areas that match the buyer demographics for PHEVs.
Step 5.3:	Establish interconnection standards and policies and a net-metering rate for customers connecting small generation and/or storage sources to the grid.

6. HOME AREA NETWORKS

Home area networks (HANs) *incorporate all types of appliances and consumer devices that send signals to and from the utility and customer via an AMI or the Internet.*

The HAN is a computer automation system for the home or small commercial business. It integrates devices through the Internet or connects the electric utility to the user through AMI, allowing the user to be proactive in the use or generation of energy. The HAN will play a major role in making the grid more efficient and in moderating rate impact for the customer. The HAN begins on the customer side of the meter and will be made up of PHEVs, renewable and/or DG, HVAC systems, pool pumps, intelligent appliances and plug-load consumer devices like MP3 players, cell phones and iPods authenticated to the electric utility on a secure network owned by the home or business owner. The home or business owner will have the ability to control the operation of devices on the HAN from a computer (with manual override features) to maximize the advantages for DR or DSM rate structures offered by the electric utility. Controversial issues that can occur in the build out of a HAN include:

- Utility grade (99.99%) cyber security through the Web portal as it receives price signals for authenticated devices from the utility using AMI
- Standardization of device protocols for low-power ubiquitous personal networks among multiple gadget and appliance suppliers
- Ownership of customer data obtained through general power usage patterns and, perhaps more importantly, the types and usage patterns of specific devices authenticated onto the HAN
- Customer acceptance of voluntary DR/DSM and efficiency programs and the fact that if programs are not accepted, the cost of the AMI- and HAN-enabling systems still are in the rate base and will be subject to recovery
- The potential for Big Brother syndrome should consumers reject the HAN concept because of concerns about being watched and monitored by a larger entity
- Obsolescence of the technology deployed — IT, telecommunication and consumer electronics gadgets become rapidly outdated (churn)
- Retrofitting existing homes with the new technology of the HAN balanced with the basics of passive improvements such as better insulation, sealed doors and windows, and more efficient appliances
- The social justice of how limited-income utility customers build and use a HAN when they may not have Internet access or own the home

Step 6.1:	Implement a programmable thermostat DR program for 10% of residential customers that allows the utility to control the HVAC compressor within certain guidelines.
Step 6.2:	Make customer usage meter data (power and energy) available online at the rate that it is collected by the utility. This start will position the utility for advances in the HAN as they are developed.
Step 6.3:	Pilot a red light/green light in-home display to indicate high-cost/low-cost energy prices for those customers in step 6.1 and step 3.5.

7. DATA INTEGRATION MANAGEMENT

***Data integration management** coordinates long-term management and warehousing of operational and/or customer data.*

The Smart Grid will generate billions of data points from thousands of system devices and hundreds of thousands of customers. Data storage needs will explode. The data alone is overwhelming at best and at worst, completely disruptive to normal utility operations. The first phase of the knowledge management effort and a key component in the system of information technology starts with data conservation in a data warehouse. With this incredible volume of sensitive system and customer-related data, the back-office effort of a data warehouse is not to be underestimated. Access to secure data will be important, but some of the best system or customer programs may result by allowing engineers and operators the opportunity to freely analyze some or all of the data. Large computer hardware companies recognize the huge growth potential and are visibly promoting their solution concepts.

The accurate, efficient and timely transfer of meter data to the customer information system (CIS) for billing purposes is fundamentally critical to the utility. This will be made more complex by new TOU and/or net metering rate structures and any transition time from legacy meters to new advanced meter infrastructure. Call center staff will need to be thoroughly educated to handle new questions on rates and programs.

Step 7.1:	Prepare a data management request for proposal (RFP) to match the initial data requirements for the cumulative total of anticipated pilot data but scalable to the data management needs of full implementation of at least one pilot project.
Step 7.2:	Train call center staff.

8. DATA ANALYTICS AND EVALUATION

***Data analytics and evaluation** develop a better understanding of load factors, energy usage patterns and other trends that could alert operators to potential failure.*

Data must be converted to information through a knowledge management life cycle in which the data from meters, appliances, substations and distribution systems are analyzed and integrated in a manner that leads to action. A data-to-information-to-action plan will develop as a better understanding of load factors, energy usage patterns, equipment condition, voltage levels, etc. emerges. This plan should be based on analysis that integrates functional information into usable customer programs and/or operation-and-maintenance algorithms that identify trends that can alert operators to incipient failure. Data should be secure and not contain customer or proprietary information. It should allow system planners, engineers, operators and rate makers the ability to perform analysis, trending and reporting that will lead to improved customer programs and better system operation.

Step 8.1:	Make raw secured data available to key staff.
Step 8.2:	Develop condition-based maintenance algorithms with DA data or data from remote equipment monitors in substations. Use the cumulative knowledge of operations and maintenance staff to set trigger points and required actions specific to the age, manufacturer and location of the asset.
Step 8.3:	Develop operational algorithms with DA and AMI data and set trigger points and required actions for voltage/VAR control, peak load management, disconnect/reconnect and trouble call analysis.

9. REMOTE EQUIPMENT MONITORING

***Remote equipment monitoring** uses intelligent devices installed on major substation equipment to aid utilities in improving system reliability and efficiency.*

Transformers and circuit breakers are the two major substation equipment devices within the substation that can typically cause extended outages.

A transformer is the most expensive piece of equipment in an electric substation and utilities tend to push the electrical limits of transformer loading to avoid replacement. Transformer age is on the rise in the United States as a direct result of reduced capital spending. In addition, some peak loads continue to grow, potentially overloading these transformers and inevitably leading to outages.

Implementing today’s technology will enable utilities to assess transformer condition, extend the life of transformers and maximize operational efficiency. There are many devices on the market that provide load monitoring, bushing monitoring, temperature monitoring, cooling system control and/or dissolved gas analysis on the main tank and load tap changer. Installing the right combination of these intelligent electronic devices (IEDs) can improve overall electric utility reliability and efficiency.

Reliability and efficiency can also be improved by properly monitoring and maintaining substation circuit breakers. Circuit breakers are critical infrastructure to substations, providing the switching capabilities and, thus, handling high stress with every operation.

Historically, utilities have monitored circuit breaker status, breaker position and the continuous current of circuit breakers through a remote terminal unit. With this limited information, maintenance personnel can spend hours trying to locate the cause of a faulted breaker. Modern IEDs provide additional analog and status monitoring points to help pinpoint failures including trip and close times, phase current at the time of the event, duty life, air and gas temperatures, compressor pressure, motor current, compressor charge time, current leakage and more. These additional monitoring points improve electric utility reliability and efficiency by allowing for planned maintenance outages instead of unplanned equipment failures.

Step 9.1:	Implement a pilot project for remote transformer monitoring on 5% of the transmission class transformers on the system.
Step 9.2:	Implement a pilot project for remote circuit breaker monitoring on 5% of the transmission class breakers on the system.
Step 9.3:	Based on pilot project results, implement this proven technology system-wide.

10. ENERGY EFFICIENCY AND MANAGEMENT

***Energy-efficiency** services help commercial and industrial customers shift loads and reduce operating expenses.*

Perhaps one of the most fundamental changes we can make immediately deals with that of our load-side management. As discussed above, DR and DSM can and should be utilized on a grid level to minimize generation cost at any given time. While these programs are developed and debated, there is an immediate solution that can reduce load on the grid. Energy efficiency is the easiest and cleanest method of dealing with the increasing load on the nation's grid. By implementing efficiency programs, commercial and industrial consumers can significantly reduce both their overall energy use and their peak demand. Much of the technology today allows us the benefit of replacing existing equipment and realizing an attractive payback due to utility cost savings. Electric utilities have been supportive of these programs for many reasons, one of which is the deferment of increased generation capacity. In an increasingly stiff regulatory market on emissions and fossil fuel-fired plants, utilities are more willing to incentivize customers to execute energy-efficiency and demand-reduction programs. These incentives help customers who might not otherwise see the financial benefit of energy-efficient capital improvements.

Commercial and industrial customers account for 63% of the electric load on the grid, despite making up only 13% of the total customers. This makes them the obvious target for efficiency programs. The EMS is likely to already exist in these facilities or be justifiable with the energy savings it can create. The first step in managing commercial peak load and overall use is to have an effective tool that can decide when to cycle equipment such as HVAC equipment, large chillers, boilers, fans, lighting, and data centers or manufacturing equipment, especially for the major energy users. In an age where data is becoming more available and easier to capture, it is imperative that a comprehensive EMS is used at the facility level.

Innovations large and small are making site management of energy users easier. Tremendous efforts into thermal storage techniques are showing success in the marketplace, and effective use of these devices provides flexibility in cooling and heating loads on the grid. The efficient storage of energy has been an elusive goal — and still is in some aspects — but storing thermal energy is becoming more feasible and, consequently, financially attractive. A common technique in thermal storage is the making of ice at night, when chillers are more efficient and electric rates are cheaper, and using the ice for daytime cooling. Customers on TOU DSM programs, can benefit from this technology by using electricity when it is least expensive. Utilities benefit from offsetting expensive generation like simple-cycle engines and avoid purchasing expensive power on the spot market.

The largest roadblock to energy-efficiency programs is simply the awareness that they exist, and that their implementation can result in attractive paybacks. There are thousands of kilowatts being wasted every day that create a strain and expense to our grid. With an effective energy-efficiency and management program, this use could be avoided, to the benefit of customers, utilities and the environment.

Step 10.1: Implement a thermal energy storage (TES) pilot using ice storage on 5% of the large (greater than 200 kW) commercial customer base. Aggregate the TES from various locations into a utility-controlled DR program.

SUMMARY

The Smart Grid is the convergence of IT and operational technology applied to the electric grid, allowing sustainable options to customers and improved security, reliability and efficiency to electric utilities. Our industry has an opportunity to deploy a smarter electric grid that many believe will help our country and world meet many of the great challenges before us. This systematic deployment strategy is a start. Real-time price signals from the generator to the refrigerator may just be the beginning.

We must think and act creatively. The electric utility industry will not meet tomorrow’s challenges by using yesterday’s ideas. It will not be easy — nothing great usually is.

Let the future begin.

ABOUT THE AUTHOR

Michael E. Beehler, PE, is an associate vice president in the Burns & McDonnell Transmission & Distribution Group. He graduated from the University of Arizona in 1981 with a bachelor’s degree in civil engineering. He received his MBA from the University of Phoenix in 1984. Mike is a registered professional engineer in eight states and is a fellow in ASCE and a member of IEEE.

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SYSTEMATIC APPROACH FOR A SMART GRID DEPLOYMENT STRATEGY

1. PROGRAM MANAGEMENT

Step 1.1	Meet stakeholders and define the Smart Grid.
Step 1.2	Perform a gap analysis.
Step 1.3	Write and present a PEP.
Step 1.4	Document the process through all phases of development.

2. BUSINESS ANALYSIS

Step 2.1	Prepare cost estimates from the gap analysis.
Step 2.2	Consider application for Smart Grid investment grants.
Step 2.3	Present to management and regulators for approval and rate recovery.
Step 2.4	Agree with regulators on rate structures and cost recovery mechanisms for lost kilowatt-hour sales.

3. DEMAND-SIDE MANAGEMENT

Step 3.1	Develop and market a residential and small commercial (under 200 kW) TOU rate that adequately incentivizes customers to shift load to off-peak periods to promote DSM.
Step 3.2	Develop and market a large commercial TOU rate that makes several load-shifting technologies more economically attractive to customers.
Step 3.3	Develop and market large commercial DR rate that adequately incentives customers to curtail load when needed by the utility.
Step 3.4	Develop and market a residential and small commercial net-metering rate that allows customers to sell electricity back into the grid to promote renewable DG.
Step 3.5	Develop and market a residential pay-as-you-go metering program for small residential customers to include the poor, elderly, apartments, vacation homes and customers who aren’t interested in adoption of the technology.
Step 3.6	Develop a passive efficiency weatherization program for groups in step 3.5.

3a. TELECOMMUNICATIONS AND NETWORK ENGINEERING

Step 3a.1	Match the telecommunication technology with the specific development strategy or strategies it is designed to serve and at similar reliability levels (SAIFI and SAIDI) of the existing, surrounding distribution assets and system.

3b. NORTH AMERICAN ELECTRIC RELIABILITY CORP. COMPLIANCE

Step 3b.1	Follow DOE initial considerations for standards development (through National Institute of Standards and Technology) for cyber security and any NERC requirements that may apply.

4. DATA ACQUISITION TECHNOLOGIES

Step 4.1	Identify potential green circuits in older service area and apply DA.
Step 4.2	Conduct an AMI pilot on randomly selected and solicited 1% of large residential and small commercial customers on newer underground circuits.

5. DISTRIBUTED GENERATION

Step 5.1	Develop a solar-photovoltaic-rooftop rebate program for small and large business customers at the penetration rate of 1% of commercial customer base.
Step 5.2	Install PHEV charging stations for 1% of the large residential and small commercial accounts in areas that match the buyer demographics for PHEVs.
Step 5.3	Establish interconnection standards and policies and a net-metering rate for customers connection small generation and/or storage sources to the grid.

6. HOME AREA NETWORKS

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