

A WORLD BANK STUDY



Practical Guidance for Defining a Smart Grid Modernization Strategy

THE CASE OF DISTRIBUTION

REVISED EDITION

Marcelino Madrigal, Robert Uluski,
and Kwawu Mensan Gaba



WORLD BANK GROUP

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The Case of Distribution

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Marcelino Madrigal, Robert Uluski, and Kwawu Mensan Gaba



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Executive Summary

There is no one definition of the smart grid concept. Instead, smart grids are defined differently around the world to reflect local requirements and goals.

What is clear, however, is that the grids of today will not support the energy goals of the future. The integration of large shares of renewable energy, improvements in the reliability of services, and the achievement of higher levels of energy efficiency across the value chain will require power grids that are largely different from those of today.

What Are Smart Grids and Why Are They Relevant to Utilities in All Countries?

To support the policy goals of the energy sector, electricity grids require constant updates. The so-called “smart” grid should be understood as a conceptual vision of a grid that will enable the achievement of sector goals. Grid updates may be routine in nature or comprehensive, but they should always be carefully planned to align with sector goals. Planners would also do well to take note of international experience. In many cases, operators will be able to save significant time and money by understanding the lessons learned elsewhere around the globe.

Necessary updates encompass grid modernization using conventional infrastructure as well as advanced digital information and telecommunication technologies. Improvements in grid monitoring, protection, and control will enable the delivery of electricity services in a more efficient, reliable, and sustainable manner. The resulting smart grids are therefore key to achieving sustainability goals in the power sector.

Both the “soft” and “hard” components of grids need be modernized to enable the integration of renewable energy resources, facilitate more active consumer participation, and improve the quality of services and the resiliency of grids in varied and challenging operational environments. The soft components relate to operational rules and regulations that support grid operation and development. The hard components involve the grid infrastructure itself and the introduction of new control and communication technologies.

The concept of the smart grid is relevant to any grid regardless of its stage of development. What varies are the magnitude and type of the incremental steps

toward modernization that will be required to achieve a specific smart grid vision. For instance, a grid that intends to integrate 40 percent of renewables will require different modernization steps from a grid that plans to integrate a smaller amount of renewables but also improve its reliability.

What Can Utilities Do to Define Their Smart Grid Vision and Plans?

Defining a smart grid vision that is aligned with broader power sector goals is key to determining which modernization steps should be taken. The current state of the grid, the desired vision, and available technologies—properly prioritized by their costs, benefits, and risks—should then be used to define the incremental steps needed to move forward.

This document provides some practical guidance on how utilities can define their own smart grid vision, identify priorities, and structure investment plans. While most of these strategic aspects apply to any area of the electricity grid (transmission, distribution, off grid), the document focuses on the segment of distribution.

The guidance includes key building blocks that are needed to modernize the distribution grid. One such block is the intelligent electronic device (IED) that, when installed in substations and feeder locations, will enable the electric distribution utility to visualize and control the electric distribution system in ways that were not possible with previous-generation electromechanical devices. Another key building block is a two-way communication network that will enable the electric distribution utility to monitor and control the performance of its electric distribution assets from its headquarters or a distribution control center.

How Can Smart Grids Benefit the Distribution Sector?

Smart grids impact electric distribution systems significantly and sometimes more than any other part of the electric power grid. At many electric utilities, the operation of the electric distribution system is being transformed from mostly manual, paper-driven business processes through the introduction of electronic, computer-assisted decision making. Advances in control and communication technology now permit the automatic or semi-automatic and remote operation of distribution equipment and facilities that in the past could only be operated manually.

In developing countries, modernizing the distribution grid promises to benefit the operation of electric distribution utilities in many and various ways. These benefits include improved operational efficiency (reduced losses, lower energy consumption, and so on), reduced electrical demand during peak load periods, better overall service reliability, and ability to accommodate additional distributed generating resources without adversely impacting overall power quality. Benefits of distribution grid modernization also include improved asset

utilization (allowing operators to “squeeze” more capacity out of existing assets) and workforce productivity improvement. These benefits can provide more than enough monetary gain for electric utility stakeholders in developing countries to offset the cost of grid modernization.

Some of these core smart grid benefits may be achieved by electric distribution utilities that have not, as yet, advanced very far in their process of grid modernization. For example, lowering the voltage set point on an existing electromechanical voltage regulator can reduce electrical demand and improve the overall efficiency of the distribution system.

Which Funding and Regulatory Issues Should Be Taken into Consideration?

The amount of effort and investment needed to accomplish a high level of grid modernization depends upon the current level of modernization, which can range from having manual control only (no automation at all) to fully automated control and continuous monitoring of all available distribution assets. Four levels of grid modernization are outlined in this report. The guidance suggests how electric utilities in developing countries can progress from their current level of grid modernization to an advanced level, and identifies projects that may be accomplished at each level to achieve valuable benefits such as higher efficiency, lower demand, improved reliability, better ability to accommodate distributed generation (including distributed renewables), and improved asset utilization overall. The report also provides examples of grid modernization projects and explains the potential benefits that can be achieved (in monetary terms) for a given investment range. Importantly, a utility that is at a relatively low level of grid modernization may “leapfrog” across one or more levels of modernization to achieve some of the benefits offered by the highest levels of grid modernization.

Finally, the report describes some funding and regulatory issues that may need to be taken into account when developing smart grid plans. Traditional capital investment plants in the power sector need be informed and complemented by the costs and funding requirements of appropriate levels of grid modernization. With regard to funding, the report suggests that some level of modernization should always be part of utilities’ capital expenditure programs. Only higher levels of modernization that use untested technologies or will radically transform a grid’s business bottom line may require special regulatory treatment.

Abbreviations

AMI	advanced metering infrastructure
AMR	automatic meter reading
BESS	Battery Energy Storage Systems
CBA	cost-benefit analysis
CES	community energy storage
CFL	compact fluorescent lamp
CHP	combined heat and power
C&I	commercial and industrial
CICS	Customer Information Control System
CPP	critical peak pricing
CVR	conservation voltage reduction
DA	distribution automation
DAS	distribution automation system
DER	distributed energy resource
DG	distributed generation
DLC	direct load control
DMS	distribution management system
DoE	U.S. Department of Energy
DR	demand response
DSCADA	distribution supervisory control and data acquisition
DSM	demand side management
ECIS	energy, climate, and infrastructure security
EMS	energy management system
EPRI	Electric Power Research Institute
ES	engineered systems
ESB	Electricity Supply Board
EV	electrical vehicle
FAN	field area network
FAT	factory acceptance test

FCI	faulted circuit indicator
FERC	Federal Energy Regulatory Commission
FLISR	fault location isolation and service restoration
FMI	Fast Message Interleave
FTA	file transfer algorithm
FTP	File Transfer Protocol
GHG	greenhouse gas
GIS	geographic information system
GOOSE	generic object-oriented substation event
GPS	global positioning system
HMI	human-machine interface
HVAC	central heating, ventilation, and air conditioning
I/O	input/output
IEA	International Energy Agency
IEC	International Electrotechnical Commission
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
IHD	in-home display
IP	Internet Protocol
IRIG	Inter-range instrumentation group
ISO	independent system operator
IT	Information technology
IVR	interactive voice response
LAN	local area network
LDC	line drop compensation
LED	light-emitting diode
LTC	load tap changer
LTV	load to voltage
MAC	Media Access Control
MMS	manufacturing messaging specification
MPLS	Multiprotocol Label Switching
msec	millisecond
MTBF	mean time between failures
NEETRAC	National Electric Energy Testing Research and Applications Center
NGO	nongovernmental organization
NIST	National Institute of Standards and Technology
NNSA	National Nuclear Security Administration

NTP	Network Time Protocol
OECD	Organisation for Economic Co-operation and Development
OLPF	on-line power flow
OMS	outage management system
ONR	optimal network reconfiguration
OPGW	optical ground wire
OT	operational technology
PCM	protection, control, and monitoring
PEV	plug-in electric vehicle
PLC	programmable logic controller
PMU	phasor measurement unit
PNNL	Pacific Northwest National Labs
PPN	physically private network
PTP	precision time protocol
PV	photovoltaic
R&D	research and development
RES	renewable energy source
RF	radio frequency
RTO	regional transmission organization
RTP	real time pricing
RTU	remote terminal unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAS	Substation automation system
SCADA	Supervisory control and data acquisition
SDG&E	San Diego Gas and Electric Company
SG	smart grid
SGCC	State Grid Corporation of China
SGIP	Smart Grid Interoperability Panel
SNL	Sandia National Laboratories
SNTP	Simple Network Time Protocol
SOM	switch order management
STATCOM	static synchronous compensator
SV	sampled values
SVC	static VAR compensator
TDM	Time division multiplexing
THD	total harmonic distortion
THESL	Toronto Hydro-Electric System Ltd.

TLM	transformer load management
TOU	time of use
UHV	ultrahigh voltage
UISOL	utility integration solutions
USB	Universal Serial Bus
VAR	volt-ampere reactive
VLAN	virtual LAN
VPN	virtual private network
VVO	volt/VAR optimization
WAN	wide area network

The Concept, Role, and Priorities of Smart Grids

Introduction: Smart Grids and Their Function

As the energy industry embraces the concept of smart grids and the benefits they can offer to the environment, consumers, utilities, grid operators, and other stakeholders, it is essential that well-designed plans be developed to ensure the successful materialization of smart grid goals and objectives.

The smart grid is variously defined to reflect specific requirements and needs around the globe. A number of organizations and governments have published their own definitions (table 1.1), including characteristics and objectives. Developing a clear vision is very important in the planning process.

Regardless of the country context or overall level of development, grid modernization promises to help electric distribution utilities achieve many categories of benefits and solutions to core business problems. Such benefits include improved efficiency by reducing electrical losses (technical and nontechnical) and promoting energy conservation, reduced electrical demand during peak load periods, improved reliability, better utilization of existing assets, and more effective integration of a high penetration of distributed generation with variable output. With a smart grid in place, customers will be better informed and may receive incentives to voluntarily modify their energy consumption patterns as needed to help address the utility company's operational problems from the demand side.

Some of the core benefits may be achieved by electric distribution utilities that are just starting to modernize their grid. For example, lowering the voltage set point on an existing electromechanical voltage regulator can reduce electrical demand and improve the overall efficiency of the distribution system.

While there is no common definition of a smart grid, there is a clear consensus that the grids of today will not be able to meet the energy demands of the future.

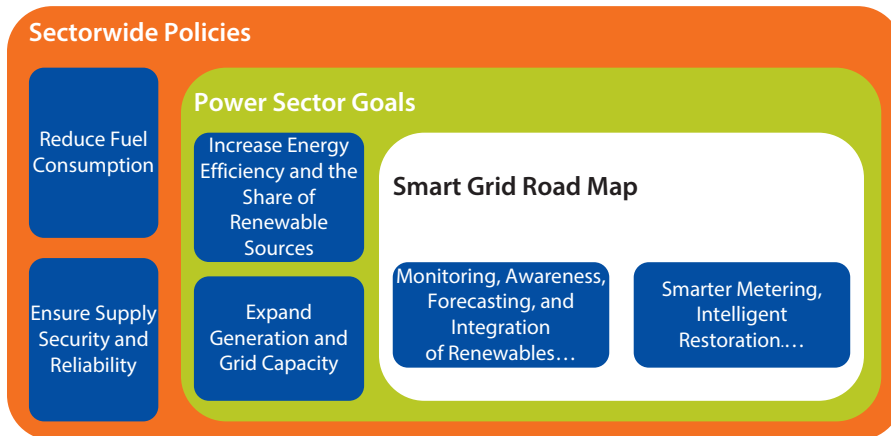
Table 1.1 A Smart Grid: Various Definitions

<i>The Smart Grid European Technology Platform</i>	<i>The U.S. Department of Energy</i>
The Smart Grid European Technology Platform defines a smart grid as an electricity network that can intelligently integrate the actions of all users connected to it—generators, consumers, and those that do both—to efficiently deliver sustainable, economic, and secure electricity supply.	In the U.S. Department of Energy definition, a smart grid uses digital technology to modernize the electric system—from large generation, through the delivery systems to electricity consumption—and is defined by seven enabling performance-based functionalities: <ul style="list-style-type: none">• Customer participation• Integration of all generation and storage options• New markets and operations• Power quality for the twenty-first century• Asset optimization and operational efficiency• Self-healing from disturbances• Resiliency against attacks and disasters
<i>The World Economic Forum</i>	<i>The International Energy Agency (IEA)</i>
The World Economic Forum defines the smart grid by key characteristics: <ul style="list-style-type: none">• Self-healing and resilient• Integrating advanced and low-carbon technologies• Asset optimization and operational efficiency• Inclusion• Heightened power quality• Market empowerment	The International Energy Agency (IEA) states that a smart grid is an electricity network that uses digital and other advanced technologies to monitor and manage the transport of electricity from all generation sources to meet the varying electricity demands of end-users. Smart grids coordinate the needs and capabilities of all generators, grid operators, end-users, and electricity market stakeholders to operate all parts of the system as efficiently as possible, minimizing costs and environmental impacts while maximizing system reliability, resilience, and stability.

Source: World Bank compilation.

A smart grid is an enabler of overall energy sector objectives and should not be viewed in isolation. Figure 1.1 outlines the role of a smart grid within sample policy and regulatory requirements. For example, an overall energy goal might be to reduce fossil-fuel consumption. One way to reduce fossil-fuel consumption is through the introduction of renewable energy (such as solar or wind energy) in the power sector. Some renewable sources may require special policy support mechanisms such as economic incentives, technology-specific auctions, feed-in tariffs, or others. To ensure that these sources are reliably and efficiently integrated, the power grid will need to be “smarter” as the share of these sources grows in the grid, that is, a smart grid is needed to implement higher-level policy goals. The integration of larger shares of renewables requires better grids, new technologies, and regulations such as interconnection performance requirements. Without these transformations the grid will be a barrier to achieving sector goals.

A smart grid is therefore a conceptual goal whose achievement will require continuous grid modernization through the use of conventional and advanced digital technologies. Better monitoring, protection, and control of the grid will in turn enable the delivery of electricity services in a more efficient, reliable, and sustainable manner.

Figure 1.1 The Role of Smart Grids in the Overall Electricity Sector

Source: World Bank.

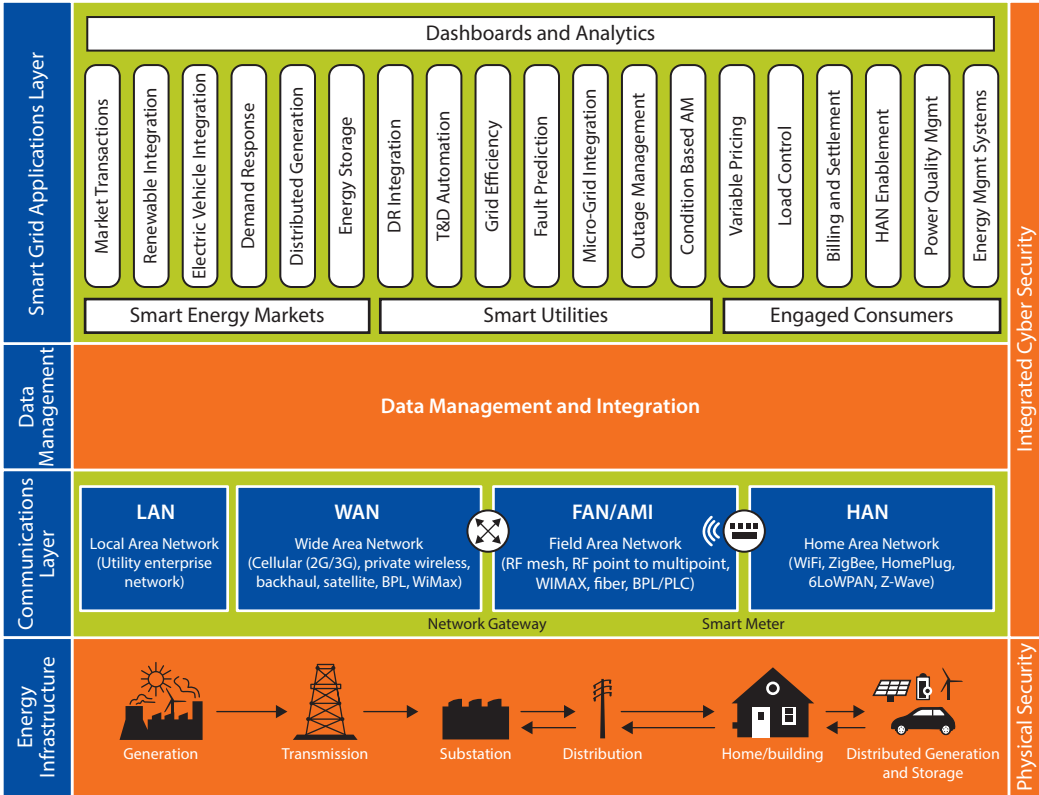
Smart grids incorporate technology that computerizes the electric utility grid to enable digital communication among grid components. For example, in conventional grids, utilities have to send workers out to read meters, measure voltage, and gather other types of useful data. In a smart grid, the components of the grid—variable and thermal generators, loads, wires, substations, transformers, even consumer appliances—have integrated sensors that carry data as well as two-way communication capabilities between the device and the utility’s operations center. That way the utility can adjust and control each device or millions of devices from a central location.

High-Level Description of a Smart Grid

Each individual smart grid of the future will encompass different goals, expectations, and assumptions. The grid is a very complex arrangement of infrastructure that interacts with natural laws. Its functioning depends on a large number of interconnected elements (monitoring, control, protection, telecommunications). A simplified way to visualize a smart grid is to think of it having four major layers (as illustrated in figure 1.2):

- **“Hard” infrastructure**, or all the physical components of the grid, such as the generation, transmission, and distribution assets that produce, transport, and deliver energy to consumers. This includes all generation technologies as well as energy storage facilities.
- **Telecommunications**, that is, all communications services that enable applications to monitor, protect, and control the grid. This includes all forms of communication from wide area networks, field area networks, home area networks, and local area networks. Technologies encompass telephony, optical fiber, leased lines, wireless communications, mesh radio, WiFi, and others.

Figure 1.2 Visualization of the Smart Grid by Pacific Gas and Electric



Source: PG&E 2011.
Note: HAN = Home Area Network.

- **Data**—with the abundance of data and information across various levels, data management techniques are necessary to ensure proper data mining and utilization of data to facilitate smart grid applications. The smart grid has given rise to collections of data sets so large and complex (also known as “big data”) that it becomes difficult to process this information using available database management tools. Newly developed data-processing tools (grid analytics) permit utilities to analyze large volumes of information that will help improve the performance of the electric distribution system.
- **Applications**, or the tools and software technologies that use and process information collected from the grid to monitor it, protect and control the hard infrastructure layer, and reinforce the grid to allow the participation of all forms of renewable energy. These are the tools and applications that enable the electric distribution utility to optimize the performance of the electric system and derive significant benefits, including the provision of solutions to core business problems. Two aims are to promote more efficient energy use among consumers and to make more efficient use of grid infrastructure.

Elements of these four layers are combined to create grid features that improve the grid's ability to achieve certain goals, such as integrating more renewables, improving reliability, and further reducing energy consumption among all elements of the grid, including the consumer. Deciding which specific application is required to achieve the smart grid vision is an important part of the planning process.

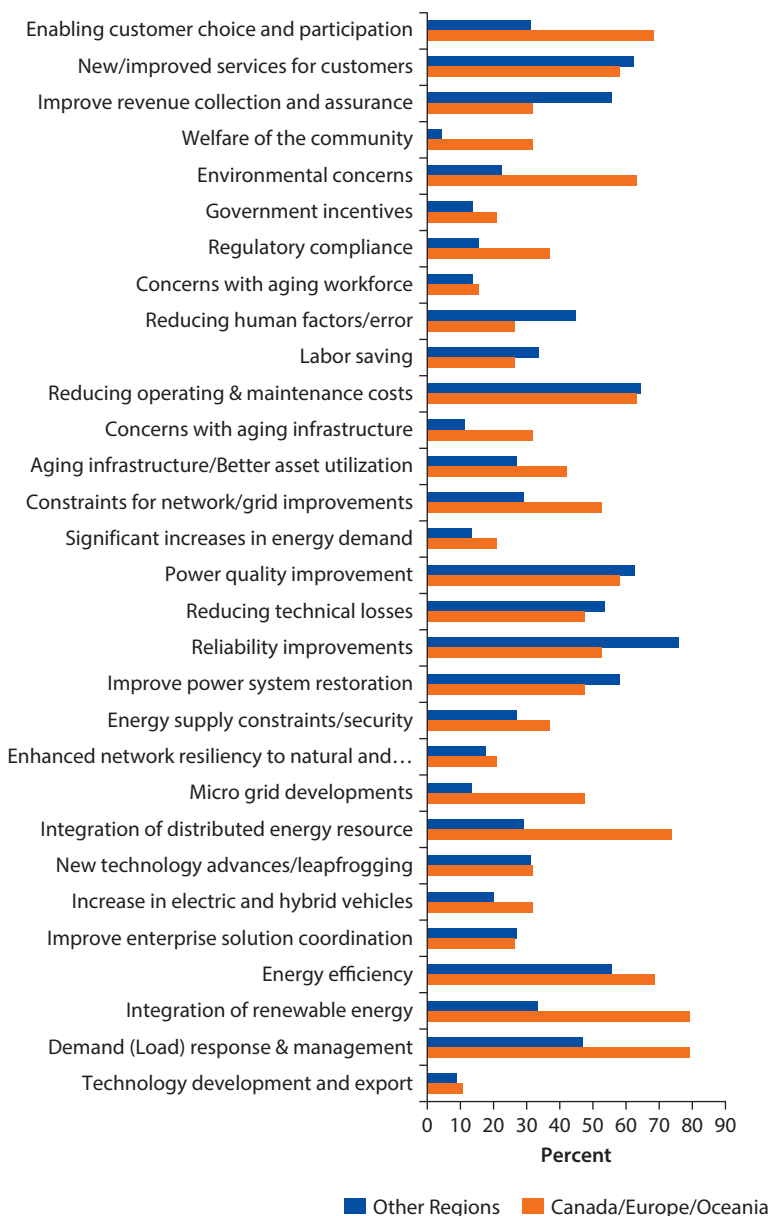
For example, if reliability is an issue at the distribution level, these layers should be combined to produce better automation of the grid and to reduce fault numbers and durations. If there is a need to implement better pricing (for example, time of use or real time) to incentivize consumers to use energy more efficiently or to control nonpaid energy, the grid may need better meters (smart meters) that can track hourly consumption and can collect such data remotely for more efficient billing. A grid that will integrate large shares of solar power at the distribution level may need better monitoring and grid regulations to ensure that distribution generation does not impact grid reliability negatively and that the expected performance is achieved.

Since there is an unlimited number of potential applications that combine features of these four layers of the grid to improve performance, it is very important that priorities are defined. A smart grid vision, which will further develop into specific applications and investments, needs to follow from clearly defined energy sector goals.

A popular industry approach to developing smart grid plans involves the development of road (route) maps that (i) facilitate understanding and cooperation among the many stakeholders in the smart grid arena; (ii) identify the vision for a particular smart grid as well as the pillars to support this vision; (iii) establish milestones with actionable policy, regulatory, and technology elements; and (iv) define metrics to measure success. This chapter will describe some elements that can be used in general (for any sector, such as transmission and distribution) to define such priorities and meet specific grid challenges.

Examples of Electric Utilities' Smart Grid Road Maps

Utilities structure their vision of a smart grid around specific challenges. An international survey carried out in 2010 (figure 1.3) shows that drivers for countries with more developed power grids (including policy and regulation)—such as Canada and the countries of Europe and Oceania—place higher emphasis on the integration of renewable energy, demand response management, environmental concerns, and enabling consumer participation and choices. Most other countries focus on the basics of improving reliability, restoring power, improving revenue collection, and reducing losses. Some drivers were equally important for all the countries, independent of their power sector development stage, such as reducing operating and maintenance costs and improving power quality. It is likely, therefore, that the smart grid vision for each of these countries should be different.

Figure 1.3 Smart Grid Drivers for More Developed and Developing Power Systems

Source: ESTA Survey on International Smart Grid Drivers, <http://www.estainternational.com/ESTA/Home.html>.

The following subsections summarize the main pillars of the smart grid visions in several utilities in select countries. Appendix B describes road maps from other countries and utilities in more detail.

China State Transmission Grid

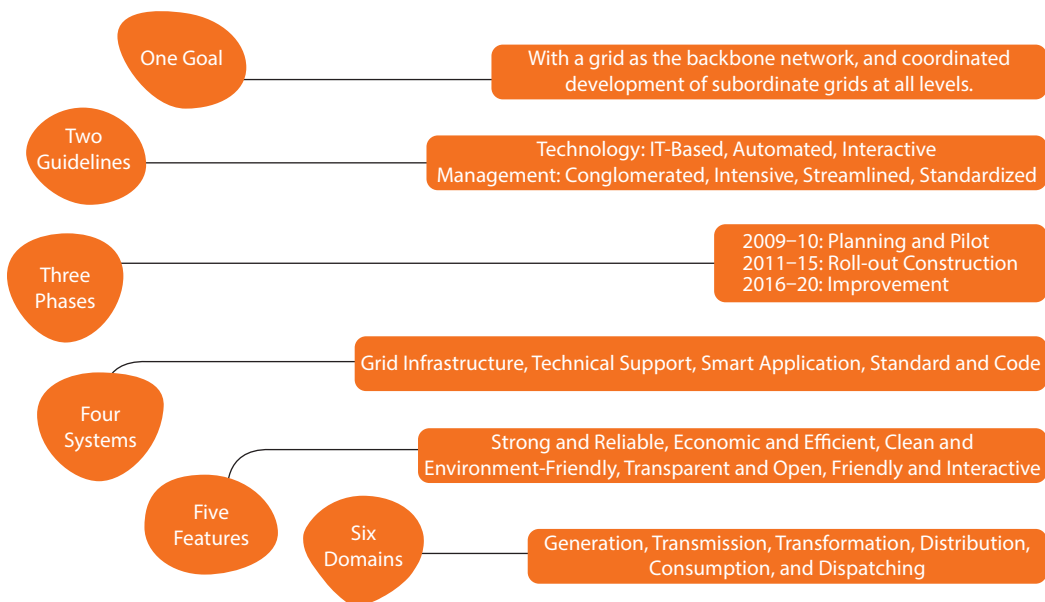
The State Grid Corporation of China (SGCC) is the power transmission entity serving the electricity sector throughout most of China, and has focused its smart grid vision on the development of a “strong and smart” grid based on an ultrahigh voltage (UHV) grid backbone to optimize energy resources allocation, improve clean energy access, and meet power demand growth. The SGCC-proposed UHV grid backbone is coordinating the development of subordinate grids at all levels; each is based on information technology (IT), automated, and interactive.

Figure 1.4 shows the strategic road map proposed by the SGCC. This comprises the definition of a goal, guidelines for the technology and management of assets, development phases (pilot, rollout, assessment, and improvement), systems, features (characteristics), and domains of action.

Canada-Toronto Hydro-Electric System Ltd.

The Toronto Hydro-Electric System Ltd. (THESL) approach to smart grid development and long-term plans is depicted in figure 1.5. It is a 25-year road

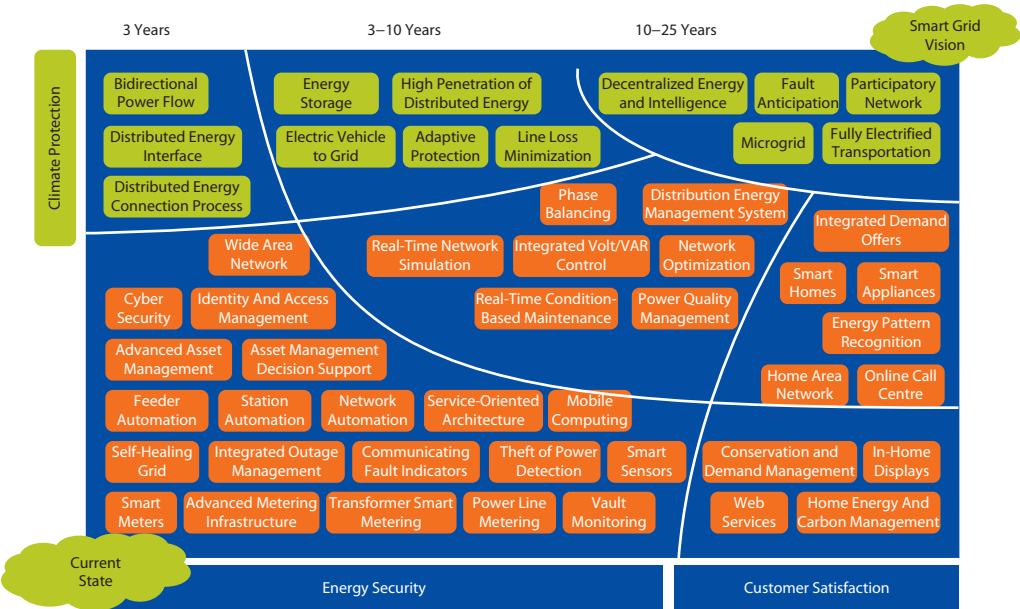
Figure 1.4 The Strategic Framework of China’s Smart Grid



Source: Developing Strong and Smart Grid: The Best Practice of State Grid Corporation of China, SGCC, 2010.

Note: UHV = ultrahigh voltage; IT = information technology.

Figure 1.5 Toronto Hydro-Electric System Ltd.: A Smart Grid Road Map



Source: Smart Grid Plan Toronto Hydro.

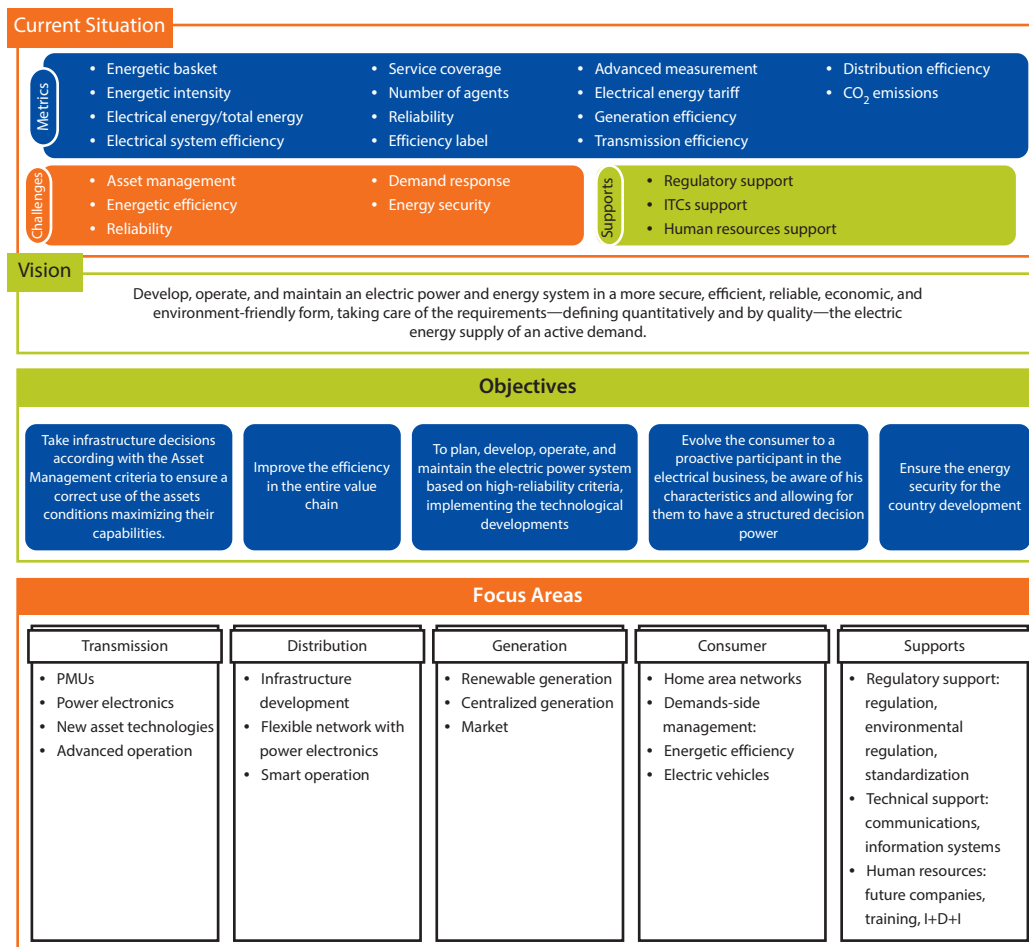
map that is expected to be completed in three phases. The vision includes three targets: energy security, increased customer satisfaction, and climate protection. The pillars include fully electrified transportation, the creation of microgrids, and the adding of distributed power, among others.

Colombia Electricity Sector

The Colombian approach to smart grid development and long-term plans is depicted in figure 1.6. The vision includes clearly defined goals such as increased security, efficiency, reliability, profitability, and environmental quality. The baseline, challenges, and actions to be taken (pillars) have been identified.

The focus areas in transmission include increased cooperation with neighboring countries, the use of phasor measurement units (PMUs) to improve system monitoring, and overall reliability. On the consumer side, demand-side management and home area networks are included as potential areas of action. On the “soft” side, the plan identifies needs to improve some regulations and work on human resources development.

The common elements of these road maps include a clear vision of the objectives being pursued and the areas or pillars of action, and a description of some of the specific actions that will be pursued to modernize the grid. Some road maps include pillars of action for other institutions, or the enabling regulatory aspects that need to be developed to pursue some of the actions.

Figure 1.6 Columbia's Electricity Sector: A Road Map

Source: Aldana and others 2011.

The following sections provide some guidance on the process of structuring a road map (and investment plan) for smart grids in the distribution sector. Understanding the drivers behind smart grids is key, as is formulating individual visions. Based on global experience and the key concepts discussed earlier, the following section provides further guidance on preparing smart grid road maps and investment plants.

The Importance of Defining Priorities: Elements of a Road Map

Smart grid planners should follow the step-by-step procedures necessary to develop a holistic smart grid road map that clearly responds to sector goals (see box 1.1). A road map is a detailed description of actions to be taken by regulators,

Box 1.1 Key Definitions

<i>Road map</i>	A specialized type of strategic plan that outlines activities an organization can undertake over specified time frames to achieve stated goals and outcomes
<i>Road mapping</i>	The evolving process by which a road map is created, implemented, monitored, and updated as necessary
<i>Setting a vision</i>	The process of analyzing future scenarios and identifying objectives
<i>Stakeholders</i>	Relevant individuals who have an interest in seeing the road map developed and implemented, such as representatives from the industry, government, academia, and nongovernmental organizations (NGOs)
<i>Implementation</i>	The process of putting a road map into action, by carrying out projects and initiatives that address road map tasks and priorities, and by monitoring progress using a tracking system.

utilities, countries, or regions embarking on smart grid programs. Once a smart grid road map is prepared and approved by stakeholders, it will form the foundation for all future smart grid activities. It should be complemented by detailed implementation plans to realize the ultimate smart grid vision.

With the global focus on strategies to develop smarter energy grids, many entities at the national, regional, and local levels are developing plans to capitalize on the benefits that a smarter grid can provide to its stakeholders.

A key element of the successful deployment of a technology initiative, such as a smart grid, is the development of a strategic road map. A road map (i) brings to focus the interest of stakeholders into a succinct plan, (ii) sets a vision, (iii) identifies technology needs, (iv) supports better investment decisions, and (v) provides a timeline for achieving goals.

The development of a road map—also known as road mapping—is an evolutionary process. Road maps must be reviewed and updated regularly to meet changes in requirements, reflect advancements in technology, correlate with workforce development, reflect time constraints, and harmonize with budgetary constraints.

There are many stakeholders in the energy industry, each with special perspectives on the industry and its services. These stakeholders may include governmental bodies; regulatory entities; utilities for generation, transmission, and distribution of electricity; independent power producers; merchant transmission companies; industrial complexes; residential, industrial, and commercial consumers; technology firms; research organizations; academia; and others. It is important to leverage the knowledge of all stakeholders to develop an all-encompassing and holistic plan.

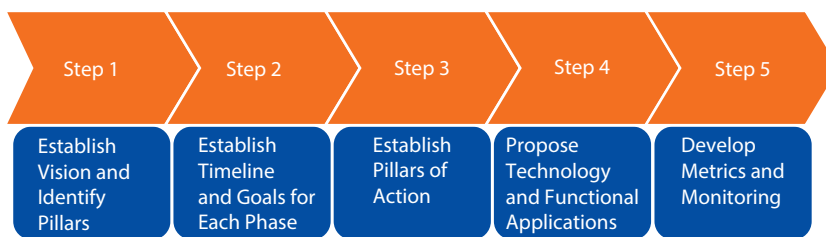
A review of available literature and the road maps developed by several utilities reveals there are several key steps involved in preparing a smart grid road map. Appendix A contains an overview of various road mapping methodologies

that have been proposed by organizations such as the International Energy Agency (IEA), the U.S. Electric Power Research Institute (EPRI), and the U.S. Sandia National Laboratories (SNL).

It is important to mention that smart grid road maps may have various scopes. For example, a road map could be for an entire vertically integrated utility, a transmission company, or a broader country plan where other industrial policy objectives are involved.

Figure 1.7 shows some of the basic steps involved in defining the priorities of a road map.

Figure 1.7 Five Basic Steps in Defining Priorities of a Road Map



1. *Vision statement.* The long-term vision for smart grids is established based on energy sector goals. Key roles and responsibilities of actors are defined.
2. *Definition of a timeline.* The timeline for achieving the smart grid vision is established—it may be incremental and in phases. Each phase has clear objectives and goals.
3. *Pillars of action.* Based on the vision of the road map, the key pillars of action are established. The current baseline is reviewed to leverage achievements and current assets to estimate the additional effort needed. Risks, costs, and potential barriers are analyzed.
4. *Technology and functional applications.* Policies, regulations, and technology for each time period and each pillar are suggested. The challenges associated with smart grid implementation are also addressed.
5. *Metrics and monitoring.* Performance metrics are developed to measure the success of smart grid implementation.

Step 1: The Smart Grid Vision Statement and the Importance of Governance

A vision statement is a succinct articulation of the goals and objectives of a smart grid for the nation or the entity engaged in smart grid implementation. The vision is established by reviewing overall long-term objectives at a national, regional, local, or company level. Examples of broad government objectives for the power sector may include the following:

- Active participation by consumers
- 25 percent of renewable generation by 2020

- 20 percent reduction in carbon footprint
- 20 percent energy-efficiency gains among all classes of consumers
- Development of new products, services, and markets (workforce development)
- Improved financial health of utilities
- Increased reliability and efficiency of electricity transmission and distribution.

This vision will form the basis and foundation for all smart grid pillars and activities.

Deploying smart grids at the utilitywide level or in specific segments of the sector will require proper coordination of actors. Some form of governance should be established to structure the vision and the rest of the components in a road map. Establishing a steering committee and technical groups is common while developing a road map.

Step 2: Establishing a Timeline

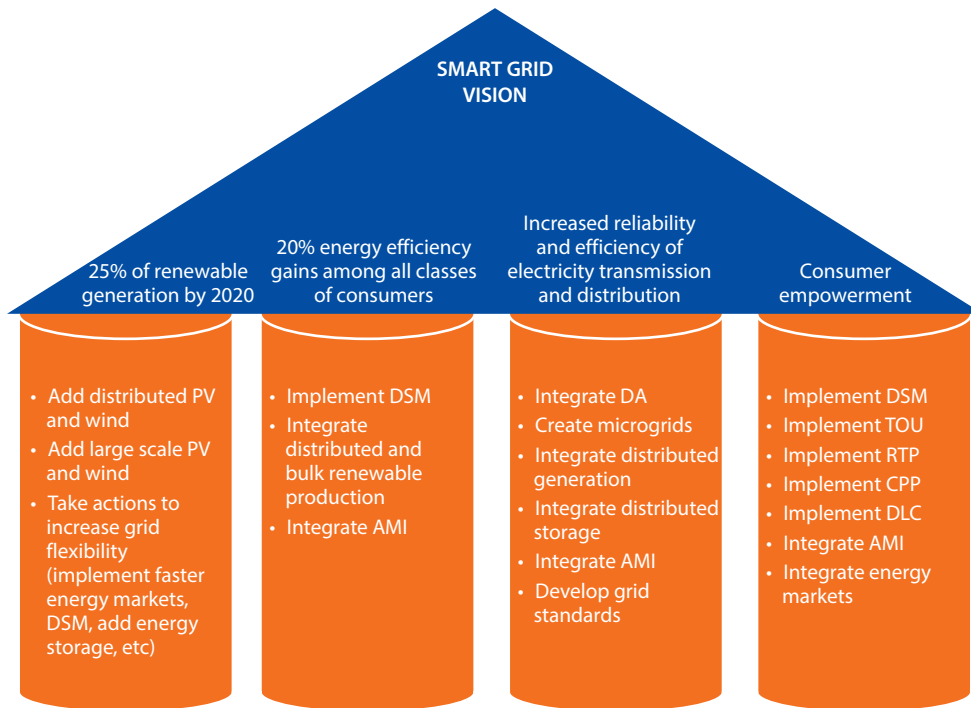
The smart grid is a concept that should be implemented in phases to allow for refinement and to ensure that the modernization activities with the highest benefits are implemented first. Different phases can be identified, and ideally will follow the general timelines set for overall sector or company goals. Actions that can immediately render benefits should be included in the short-term; medium-, and long-term projects include smart grid applications that require feedback from previous phases or actions supporting long-term goals. Not all actions should be performed at the same time, and not all grids require the same level of modernization.

Step 3: Pillars of Action

A smart grid enables the achievement of a stated vision and objectives. It is convenient to define a pillar that supports each of the vision elements. These pillars will help identify the potential actions to improve the grid. Figure 1.8 provides an example of how each vision objective may be transformed into a pillar. This includes, for example, the objective of managing a certain percentage of renewables; as a pillar, this will support energy efficiency goals. In developing countries, where demand continues to grow and reliability continues to lag behind, the smart grid vision will most likely include improving grid reliability. As such, a pillar of the smart grid plan should include all the actions that can help improve reliability.

Step 4: Technologies and Functional Applications

Deciding which technologies or functions will be deployed in each pillar requires assessing which of these applications—or their combination—have the best chances of achieving a given goal. This is perhaps the most complex step in defining the priorities of a road map. This step requires knowing the state of the grid, identifying the gaps and potential technologies to improve its performance, analyzing if such applications are cost-effective, making sure risks are identified,

Figure 1.8 Smart Grid Vision and Pillars

Source: World Bank.

Note: PV = photovoltaic; DSM = demand-side management; AMI = advanced metering infrastructure; DA = distribution automation; TOU = time of use; RTP = real-time pricing; CPP = critical peak pricing; DLC = direct load control; RES = renewable energy source.

and highlighting potential barriers (for example, regulatory) to effective implementation. Not all applications need to be advanced in nature; some applications, already commercially viable and tested in other places, may not need any special regulatory treatment.

Some approaches to identifying applications in each pillar are as follows:

1. *Gap analysis.* Using future goals, the smart grid vision, and the pillars, a gap analysis is conducted to identify the missing or incomplete components between the current baseline and future targets. For example, if a future goal calls for reducing the duration of outages in a year, it becomes necessary to identify the actions that are needed to achieve this (for example, automatic reclosing, and tree trimming). Another example may include the necessary actions to mitigate the complexities of the significant penetration of distributed generation.
2. *Cost-benefit analysis.* This analysis will help identify a high-level estimated cost of the actions necessary to mitigate the gaps identified in the gap analysis. What costs are associated with the various pillars—for example, improving the financial health of a utility? Do the benefits of an application outweigh its costs?

3. *Risk analysis.* This analysis helps identify the risks associated with taking or not taking a particular action. For example, does infrastructure require an upgrade to meet technology needs, or are there any capacity-building or training needs to deploy a given technology?
4. *Highlighting barriers.* This analysis identifies the barriers that must be overcome. These may relate to policy, regulations, technology, human resources, finances, and so on.

Step 5: Metrics and Monitoring

If the smart grid is to meet sector objectives, it is important to monitor performance metrics. Examples of such metrics include reliability improvements and reduced outage periods (improved System Average Interruption Duration Index and System Average Interruption Frequency Index),¹ the percentage of demand response achieved, the amount of renewable generation connected to the grid, jobs created, and so on. Metrics should be used to monitor progress and to evaluate when corrective actions or modifications to the plan may be needed.

The following chapters in this report will provide further information on how to deploy such procedures in the distribution segment. An important step is defining technologies and functional applications relevant to distribution. The next chapters provide background on how the distribution segment has evolved over time; describe some of the new technologies available in the distribution segment; and, last, outline a procedure for selecting options in a plan.

Note

1. System Average Interruption Duration Index and System Average Interruption Frequency Index.

The Evolution of Electric Distribution Systems

The Smart Grid in the Distribution Segment

Grid modernization (to achieve the so-called smart grid) impacts electric distribution systems more than any other part of the electric power grid. At many electric utilities, the operation of the electric distribution system is being transformed from mostly manual, paper-driven business processes through the introduction of electronic, computer-assisted decision making. Advances in control and communication technology now permit the automatic or semi-automatic and remote operation of distribution equipment and facilities that in the past could only be operated manually.

Electric distribution utilities have always focused on maintaining “acceptable” conditions out on the distribution feeders. Goals included the following:

- Maintain safe conditions for the electric utility workforce and the general public.
- Minimize electrical losses on the electric distribution system. This is an especially important objective for electric distribution utilities in developing countries that experience high levels of electrical losses, including both technical (I²R) losses and nontechnical losses (energy theft and unmetered loads).
- Protect the electric distribution assets from potentially damaging short circuit currents and voltage surges and sags.
- Maintain voltage within established limits (typically nominal voltage, plus or minus 5 percent) for all customers at all times under all loading conditions.
- Ensure that the loading of all electrical equipment is well within the established thermal ratings of the individual devices (often device loading has been limited to half of what the device is physically able to carry).
- Ensure reliability of the service—that is, limit interruptions and their severity.

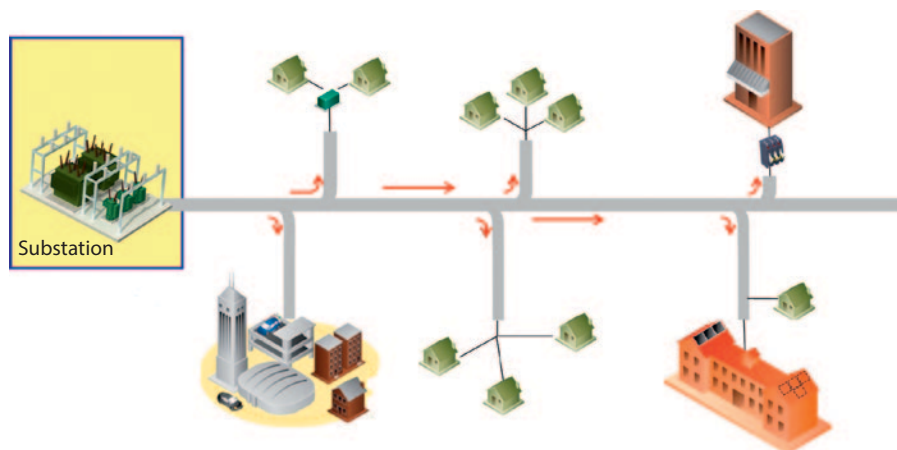
All of the above goals continue to be fundamental and essential operating requirements. But today's electric distribution utilities are seeking to make distribution system operation even more efficient and reliable—and improve asset utilization—without compromising safety and the protection of distribution assets. Utility companies are also seeking to accommodate new distributed generators that are powered by clean and renewable energy resources (wind power, solar power, and so on), and to empower end-use customers to make informed decisions about their energy usage.

The Traditional Distribution System and the System of the Future

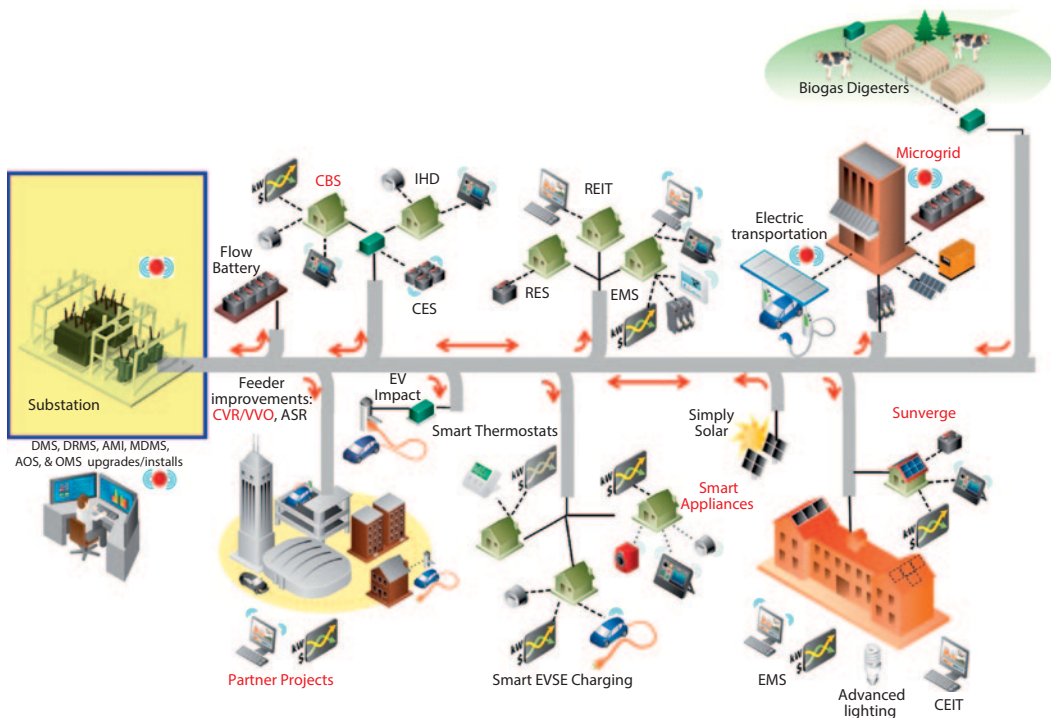
The electric distribution system has undergone significant changes over the years. This chapter identifies the changes that have occurred in terms of the level of staffed operation; operating objectives; monitoring and control capabilities; and protection, automation, control, and back-office commercial and technical management systems. The next sections describe the ways distribution systems have changed on a decade-by-decade basis. Not all electric utilities have moved forward with these grid modernization efforts at the same pace, however. While many utility companies have moved forward over the decades in the ways described in the following sections (see figure 2.2), some electric utilities continue to rely on mostly manual paper-driven processes, and have yet to deploy the intelligent electronic devices (IEDs) and communication facilities needed for grid modernization (see figure 2.1). As a result, the short-term vision and strategic road map for grid modernization will differ for each utility.

The progression of electric utility distribution grid modernization over the years is outlined in the following sections. Key aspects of electric utility operations are identified during each time period—for purposes of comparison—in the

Figure 2.1 Traditional Distribution System



Source: World Bank.

Figure 2.2 Distribution System of the Future

Source: World Bank.

following categories: overall level of automation, distribution protection and control, power-generating sources, level of centralized management and control, and the end-use customer. Table 2.1 summarizes the progression of key elements of distribution grid modernization over the years.

Before the 1980s

Before the 1980s, most electric utilities had very little or no automation and remote monitoring and control on their electric distribution system. Distribution protection, control, and metering (including end-use customer revenue metering) were handled by electromechanical devices. Figure 2.3 shows electromechanical devices that are typical of this era. These electromechanical devices performed their basic functions well but did not support automation, remote monitoring, and remote control. As a result, electric utilities were required to travel to the device location to retrieve information and perform maintenance and diagnostic activities. To reduce travel costs, many electric distribution substations were permanently staffed during this period to prepare log sheets, conduct routine inspections, and respond as quickly as possible to distribution outages.

Table 2.1 Modernizing the Distribution Grid: A Timeline

	<i>Before 1980</i>	<i>1980s and early 1990s</i>	<i>Mid 1990s to early 2000s</i>	<i>Mid 2000s to present (the "smart grid" era)</i>
<i>Overall Level of Automation</i>	Some manned substations — No remote monitoring and control	Unmanned substations; some substation SCADA	Some feeder automation; increased substation SCADA	Growing level of feeder automation; most substations automated
<i>Distribution System monitoring and analysis</i>	Manual handwritten log sheets at major substations; monthly meter readings stored for off line analysis	Limited information such as "station trouble" alarms available at some substations; more detailed information still limited to manual log sheets at major substations	Near-real time information provided for key equipment at distribution substations; some data acquired from key equipment and bell-wether meters located out on feeders; use of relational databases for storing, retrieving, and analyzing serial substation data	Many new information sources of near real time data available from substations and feeder equipment; advanced metering systems provide higher resolution meter data from consumer meter locations; new "streaming" data sources such as phasor measurement units being deployed; Introduction of grid analytics software for analyzing large and complex data sets
<i>Distribution Protection and Control</i>	Mostly electromechanical devices for protection and control; some local auto failover schemes in place	IEDs gradually appearing in substations; some auto restoration loop schemes	IEDs become standard for protection and control; growing use of auto restoration schemes; SCADA controlled Volt VAR Control schemes becoming common	IED based protection and control schemes adapt to changing conditions; control schemes "optimize" system reliability, efficiency and performance
<i>Power Generating Resources</i>	Centralized generation	Some industrial cogeneration; primarily centralized generation	Growing amount of cogeneration; low penetration of solar and wind power; still mostly centralized generation	High penetration of solar/wind power in some areas; energy storage used to mitigate DER consequences; lower dependence on central generation
<i>Centralized Management and Control</i>	Regional management with voice communications; paper maps; no remote control	Regional control centers with limited SCADA capabilities; use of automated mapping systems;	Consolidated control centers equipped with distribution SCADA; use of GIS for asset management and Outage management Systems	Growing use of advanced distribution management systems; DMS/OMS/GIS integration; model-driven applications for optimal control
<i>End customer interface</i>	Manual meter reading Some C&I meters read via phone	Manual meter reading Some C&I meters read via phone	Growing use of AMR systems; load management systems; prepayment meters	Rapid growth of AML with two way communications; time of use rates; demand response used to control selected customer appliances

Source: World Bank.

Note: SCADA = supervisory control and data acquisition; IEDs = intelligent electronic devices; DER = distributed energy resource; GIS = geographic information system; DMS = distribution management system; OMS = outage management system; C&I = commercial and industrial; AMR = automatic meter reading; AML = advanced metering infrastructure.

Figure 2.3 Electromechanical Protective Relays and Meters

Source: Uluski 2007.

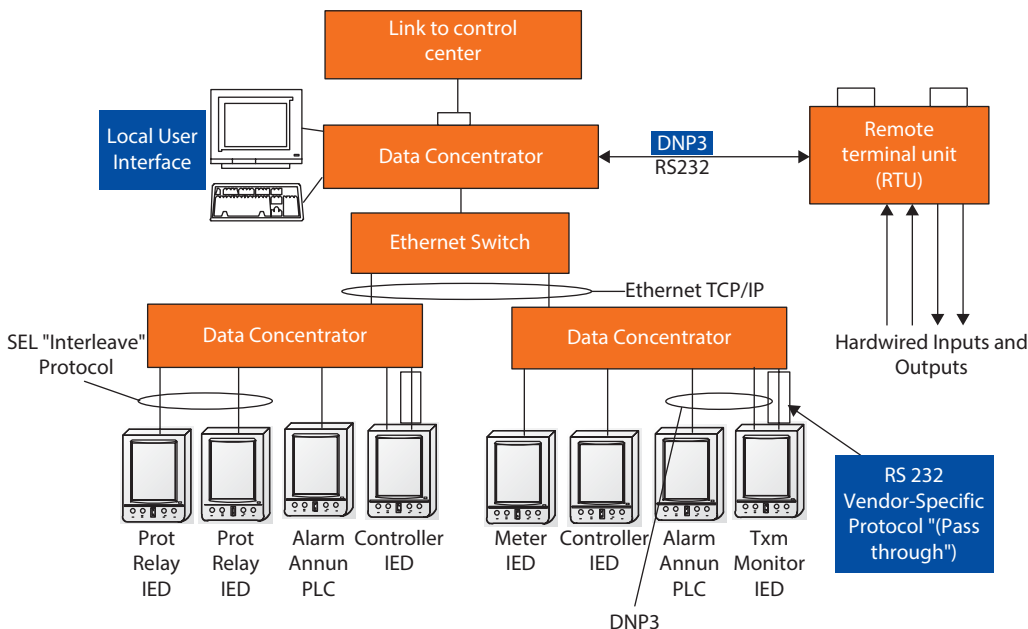
Most electric power was supplied by large-scale central generators connected to the transmission grid. No significant generating sources were connected to the distribution system during this period.

The 1980s and Early 1990s

During the 1980s and early 1990s, many electric utilities made significant efforts to reduce their dependence on field personnel for performing routine monitoring and control actions. Most, if not all, personnel were removed from distribution substations during this period. The implementation of some microprocessor-based IEDs, automatic data loggers, and supervisory control and data acquisition (SCADA) facilities at electric distribution substations eliminated many of the manual tasks performed in the past by dedicated substation operators. Figure 2.4 shows a representative substation SCADA system of the early 1990s. Most utilities also added reclosing relays to their distribution protection systems to automatically restore power quickly following temporary (self-clearing) short circuits. Remote monitoring and control during this era was still limited to the distribution substations at most utilities.

During this period, little or no remote monitoring was provided for monitoring and controlling devices located out on the feeders themselves (outside the substation fence). But some utilities began deploying loop control schemes (a simple form of fault location isolation and service restoration, FLISR) on some feeders. Figure 2.5 illustrates the operation of a 1990s version of a simple loop control scheme.

Most electric power was still supplied by large-scale central generators connected to the transmission grid. But a growing number of cogeneration facilities were installed by industrial customers on their premises to serve their own load, and sell and deliver excess power to the electric distribution utility.

Figure 2.4 Substation SCADA System

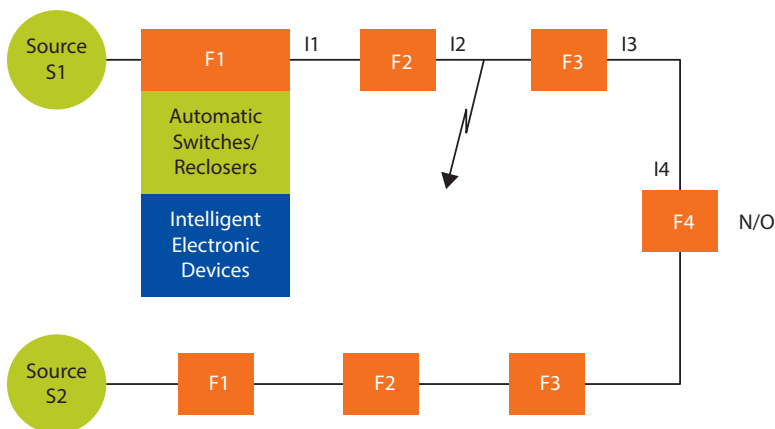
Source: World Bank.

Some commercial and industrial (C&I) customers had communicating revenue meters that were being read via telephone circuits. This allowed the C&I meters to be read more than once per month, thus enabling time-of-use (TOU) rates. Residential meters were still being read manually during this period.

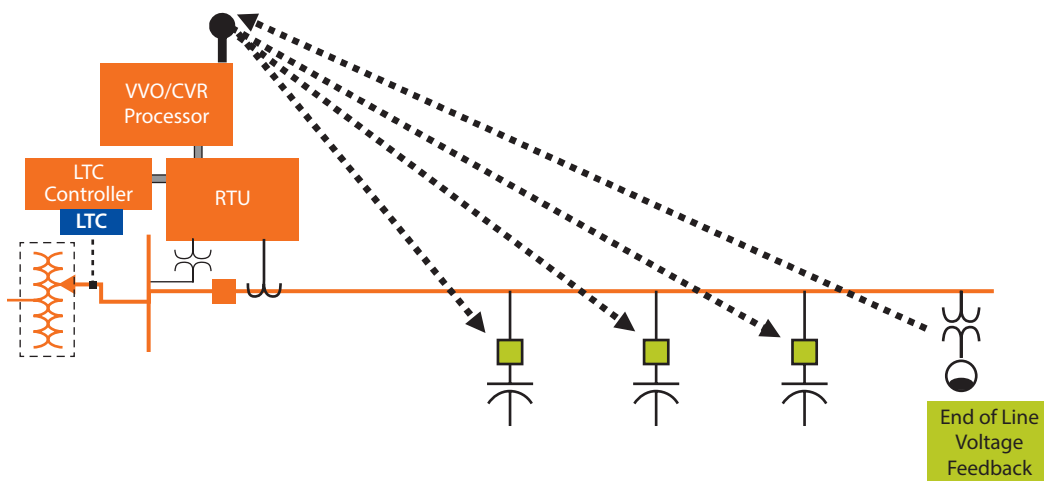
The Mid- to Late 1990s and Early 2000s

During this period, the use of digital IEDs gained widespread acceptance for the protection, metering, and control of electric utilities due to the IED's improved functionality and flexibility, smaller packaging, and remote monitoring and diagnostic capabilities. While the majority of installed devices were still electromechanical, most utilities had decided to gradually phase out electromechanical devices by installing digital IEDs in all new substations and replacing failed electromechanical devices with IEDs. Substation SCADA systems that used these IEDs as data sources had become the standard approach in distribution substations.

The level of remote monitoring and control of the distribution feeders themselves (outside the substation fence) also increased during this period. A considerable number of utilities deployed distribution SCADA-based FLISR and volt/VAR control systems to improve reliability, reduce electrical losses, and improve the overall performance of a small number of their worst-performing feeders.

Figure 2.5 Simple Loop Control System

Source: World Bank.

Figure 2.6 SCADA “Rule-Based” Volt/VAR Control System

Source: World Bank.

Note: VVO = Volt/VAR optimization; CVR = conservation voltage reduction; LTC = load tap changer; RTU = remote terminal unit.

Figure 2.6 shows a typical distribution SCADA-based volt/VAR control system from this era. While the remote monitoring, control, and automation of feeder devices was not widespread, the feasibility of using grid modernization to improve the overall performance and visibility of the electric distribution system was demonstrated during this period.

While most power was still being supplied from large central generators, a growing number of distributed generators were appearing on the distribution system. At this time, most of these units were fossil-fuel fired (diesel, natural gas, and so on), but some generators were powered by renewable generating resources

(wind, solar, bio-fuels, and so on). The level of deployment of distributed generation (DG) out on the distribution feeder generally remained small compared to the total load. But in some cases, the power inputs from distributed generators were starting to become significant enough to impact operations, including some high-voltage and protection problems caused by the reverse power flow.

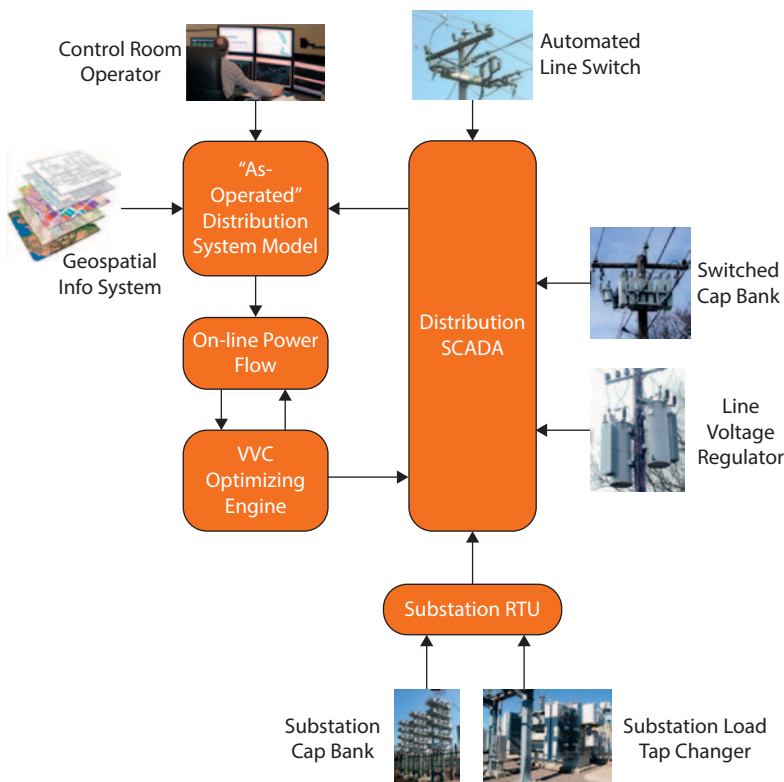
During this period, there were a number of advances in residential customer metering. Some distribution utilities began installing automatic meter reading (AMR) systems with one-way communications (including “drive-by” systems). AMR provided the opportunity to read meters more frequently and at a lower cost, and to implement new functions such as prepayment meters. Load management systems were installed at this time for peak saving purposes to reduce the need for additional generation and transmission facilities.

The Mid-2000s to the Present (the “Smart Grid Era”)

Electric distribution utilities are experiencing many significant changes during the current period, referred to in this report as the smart grid era. One of the most significant changes is the level of deployment of distributed energy resources (DERs), especially those powered by renewable resources (wind and solar power). High penetrations of wind and solar-powered generation on the electric distribution system are especially challenging due to the highly variable output from this type of generator. Sudden drop-off of solar power due to passing clouds and of wind power due to lower winds will result in a significant increase in power drawn from the electric utility substation and a resulting voltage reduction that must be countered by voltage regulator and capacitor bank operations. The sudden return of wind and solar power generators may produce high-voltage conditions that must be similarly countered. The potential for reverse power flow caused by a high penetration of DERs on the distribution feeder also poses significant challenges to existing voltage-regulating mechanisms.

In addition to providing a mechanism for mitigating the adverse consequences of variable distributed generation, grid modernization will enable electric distribution utilities to actively control customer-owned DG units to improve the efficiency, reliability, and overall performance of the electric distribution system. DG units equipped with “smart” AC inverters play a role in managing the voltage profile along the feeder as well as supplying reactive power to improve the power factor and reduce electrical losses. In addition, DG units coupled with energy storage and advanced control systems will enable electric distribution utilities to establish islanded microgrids that can continue to serve customers in the local community even when the microgrid becomes separated from the main grid and/or a widespread power outage occurs.

The need to deal with increasing penetration of DERs, coupled with the need to reduce electrical losses and improve overall efficiency, has resulted in the growth of advanced distribution model-driven volt/VAR optimization (VVO) systems. Many utilities have implemented or are currently demonstrating

Figure 2.7 Advanced Model-Driven VVO System

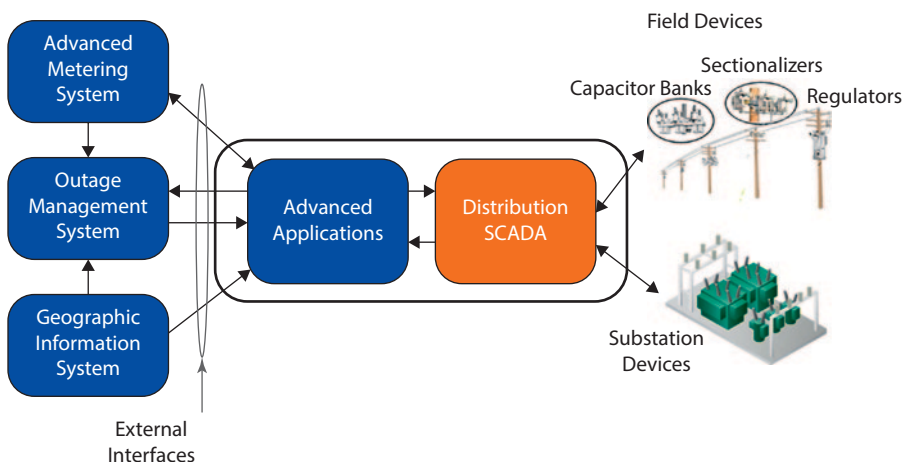
Source: World Bank.

advanced VVO on their distribution systems as a key part of their grid modernization strategy. Figure 2.7 shows a representative advanced VVO system.

Feeder automation schemes for reliability improvement, such as advanced FLISR, are also becoming more prevalent during the smart grid era.

Many utilities are also considering implementing a distribution management system (DMS) to assist in decision making and managing the increasingly complex distribution system. DMS-based applications are potentially more flexible and effective than the traditional "rule-based" systems that had previously been implemented. Figure 2.8 illustrates the major DMS components.

Many utilities are now deploying two-way advanced metering infrastructure (AMI) systems to support a wide variety of revenue-related applications (including energy theft detection) and to furnish a wealth of new, near-real-time information about customer behavior and distribution system electrical conditions. AMI systems have allowed the creation of demand-side management (DSM) programs such as demand response, which is becoming an essential system for peak-load management.

Figure 2.8 High-Level DMS Configuration Block Diagram

Source: World Bank.

Note: DMS = distribution management system. SCADA = supervisory control and data acquisition.

The addition of AMI and many new intelligent sensors in the field (in substations and out on the feeders themselves), along with high bandwidth communication facilities for integrating these devices, has enabled electric distribution utilities to acquire a wealth of new information about the performance of their assets. The deployment of PMUs at the distribution will greatly add to the huge volume of information being collected. In addition to the real-time and near-real time information that is being collected, there is a wealth of new “geospatial” information that is being stored in the electric utility’s geographic information system (GIS). The result is the collection of data sets so large and complex that it becomes difficult to process this information using available database management tools or traditional data processing applications.

As a result of this massive data-processing problem, many electric distribution utilities are turning to data analytics for managing and analyzing large and complex data sets. Data analytics involve the application of computer technologies and statistical models to enable electric utilities to make more effective decisions by transforming data into actionable intelligence.

Another element of the smart grid era is the growth of electric vehicles, which pose a significant new type of “mobile” load on the distribution system and also provide opportunities for distribution system management (vehicle-to-grid capabilities, vehicle-to-home capabilities, and so on).

Technology Innovations in Distribution Grids

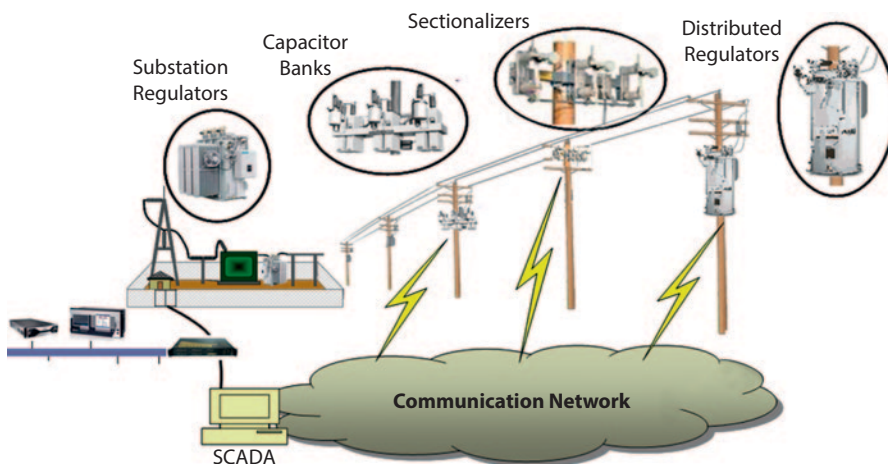
This chapter covers major technological innovations (relevant to the distribution system) in the following areas: protections; automation for reliability and service improvement; control and optimization (losses/reactive power); distributed generation interconnection, including protections and interfacing issues; and integrated supervisory control and data acquisition (SCADA) or more advanced back-office energy management systems (EMSs). These innovations are some of the building blocks needed to establish a smart grid. While the list is not complete it reflects some of the most important applications being pursued by various utilities.

The next section provides an overview of the advanced control systems and decision support systems being deployed on the electric distribution system.

Distribution System Monitoring and Control

Advanced distribution applications, such as volt/VAR optimization (VVO) and fault location isolation and service restoration (FLISR), require near-real-time data from distribution substations. Required measurements include voltage and current, real and reactive power flows, and equipment status indications. Protective relay and controller intelligent electronic devices (IEDs) can supply the necessary information via substation monitoring and control networks. Figure 3.1 depicts the vision for sources of information on the modern distribution system. Great progress has been made in recent years in migrating from traditional electromechanical devices to substation IEDs, but many utilities have a long way to go to complete this transition. Progress on smart distribution objectives may be slowed until utilities upgrade their substation monitoring and control facilities.

Smart distribution also includes numerous measurement and indication devices installed at strategic locations out on the distribution feeders. Distribution sensors include faulted circuit indicators (FCIs) that detect faults and in some cases provide fault direction as well as general-purpose sensors that record

Figure 3.1 Vision for Data Monitoring and Control

Source: McGranaghan and Uluski 2012.

Note: SCADA = supervisory control and data acquisition.

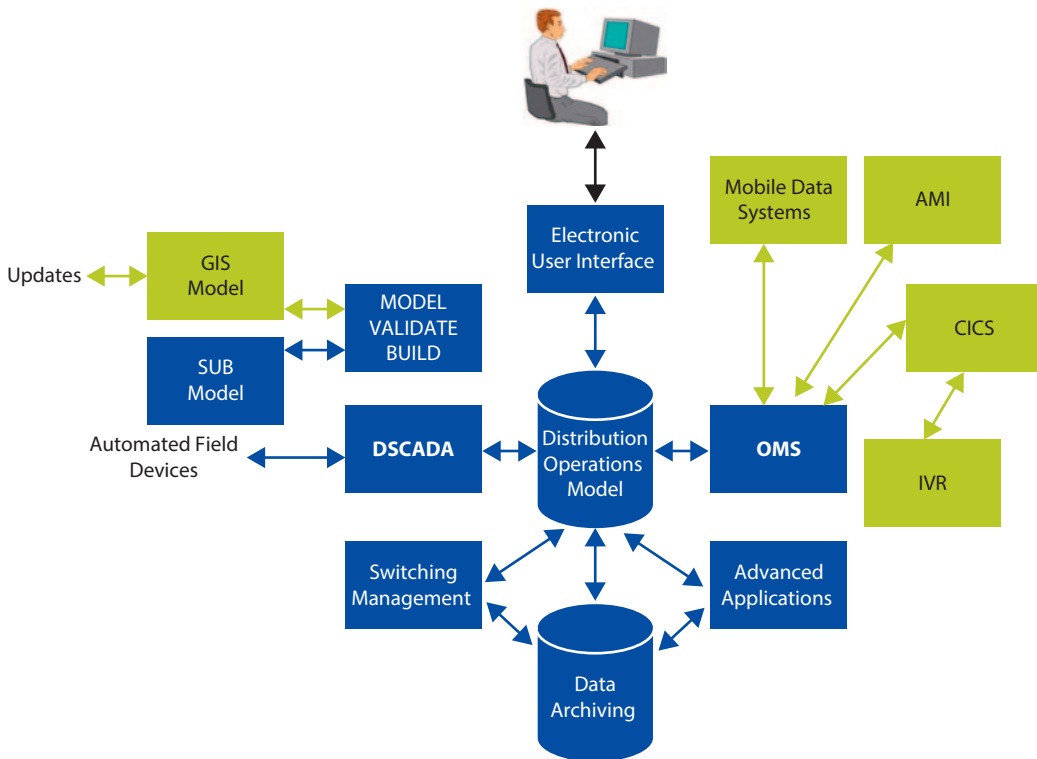
key electrical parameters and waveform data that can greatly improve visibility and support analytical needs. Distribution sensors include stand-alone devices and sensors that are imbedded in switches and other power apparatus.

Distribution Management Systems

The “smart” electric distribution system requires management by a system that has a broader, more holistic view of power system conditions: the distribution management system (DMS).

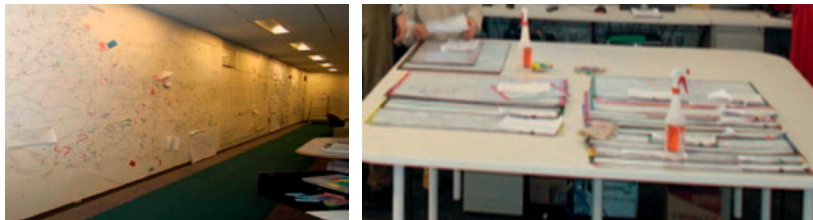
The “heart and soul” of the distribution system of the future is a DMS that integrates monitoring (“sensorization”), grid analytics, and control applications into an effective decision support system that will enable distribution dispatchers to effectively manage a distribution system of growing complexity during normal and emergency conditions. Figure 3.2 is a diagram of the conceptual DMS architecture.

Electric distribution utilities have found that mostly manual, paper-driven processes are not able to address these new operating requirements and challenges. Figure 3.3 (panels a and b) contain photographs that illustrate the transition from a paper-driven control center to a modern control center with computer-driven video displays. The distribution system of the future must include computer-assisted decision dispatcher support capabilities. These capabilities will improve the operating efficiency with semi-automated and fully automated controls that are able to respond rapidly to varying system requirements. These facilities are essential during unplanned events in which the management of many resources is beyond the capability of manual business processes. The transition from traditional manual paper-driven processes to computer-assisted decision support and closed loop control systems is at the core of grid modernization.

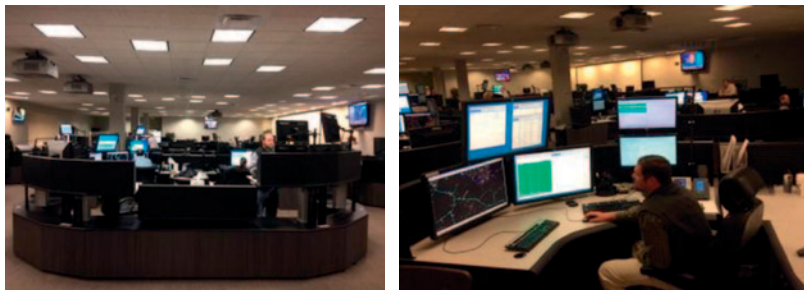
Figure 3.2 Conceptual DMS Architecture

Source: World Bank.

Note: GIS = geographic information system; DSCADA = distribution supervisory control and data acquisition; OMS = outage management system; AMI = advanced metering infrastructure; CICS = Customer Information Control System; IVR = interactive voice response.

Figure 3.3a Traditional Paper-Driven Control Center and Operator Console Design

Source: Clark 2009.

Figure 3.3b Modern Computer-Based Control Center and Operator Console Design

Source: Alabama Power 2014.

Another reason for the added complexity of today's distribution system is the greatly increased emphasis on improving ("optimizing") efficiency, reliability, and asset utilization. Today's electric distribution utilities are seeking to reduce greenhouse gas (GHG) emissions through lowering electrical losses and promoting energy conservation, demand reduction, and managed charging of electric vehicles. Utilities are also seeking to "squeeze" more capacity out of existing distribution system assets through increased loading to minimize future capital expenditures.

Distribution Protection Systems

Like all elements of the electric power grid, the electric distribution system must be protected to minimize the damage that may be caused by high magnitude current flows that may occur following a short circuit on any energized component of the electric distribution system. An electric distribution protection system typically includes protective relays, reclosers, and fuses. These devices must be time coordinated so that protective devices located farthest from the substation operate faster than protective devices that are located closer to the substation. Over the years, distribution protection systems have undergone significant changes in the technology used and the functions performed.

Traditional protection systems have relied primarily on electromechanical devices, such as the electromechanical protective relay shown in figure 3.4a. Electromechanical protective relays relied on the movement of mechanical components (spinning disk, electrical solenoid, and so on) to close and open physical electrical contacts that connect to the circuit breaker control circuit.

Electromechanical protective relays have served the industry well for many years. But many electric distribution utilities are gradually replacing electromechanical devices with microprocessor-based IEDs (see figure 3.4b) that perform protective functions along with other functions that are key to distribution grid modernization.

Figure 3.4 Protection Relay and Controller Technologies

a. Electromechanical devices



b. Intelligent electronic device



Source: Cooper Power Systems 2013 product catalogue.

The new grid modernization functionality made possible with distribution IEDs includes the following:

- *Distribution sensor and communication capabilities.* Protective relay IEDs store real-time values of current flow, voltage, and other electrical parameters needed to perform basic protective functions. These quantities can be telemetered to control systems and system operators for improved visualization and advanced application functions. As such, the protective relays and other IEDs that are installed on the distribution system are considered a basic enabling function for grid modernization.
- *Adaptive protection functions.* The modern distribution grid may experience many changes that impact the protection system requirements. In some cases, the protective relay settings or controller settings may need to be altered to reflect changing system conditions. For example, feeder reconfiguration may require new relay settings to provide complete protection of the feeder. The varying conditions associated with high penetrations of DERs may also dictate the need for dynamic or adaptive relay setting changes. IEDs also help these setting changes to be made via remote control with no intervention by field crews.

The transition from electromechanical protection and control devices to IEDs is one of the major steps in the transition to grid modernization.

Volt/VAR Optimization

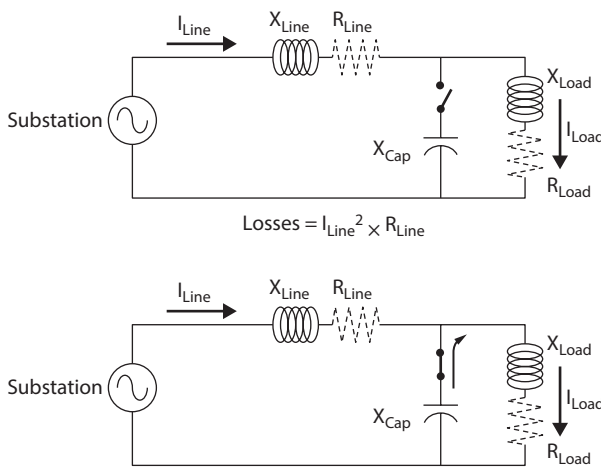
Volt/VAR control is a fundamental operating requirement for all electric distribution utilities, but this topic has taken on a whole new dimension. Volt/VAR “control” has become volt/VAR optimization (VVO), which can help electric utilities improve efficiency, reduce demand, and promote energy conservation.

VVO can play a major role in reducing the “technical” electrical losses that occur on the electric power delivery system. Technical losses primarily consist of electric power that is consumed by the power delivery facilities themselves (conductors, transformers, and so on) in the form of heat. This is energy that must be produced by central and distributed generators, but does not perform any useful work for the end-user or result in any revenue for the electric distribution utility. Many electric utilities in developing countries experience a high level of technical losses, so rescuing these losses is often a key business objective for these utilities. VVO can reduce electrical losses by switching capacitor banks on or off to compensate for reactive power drawn by the distribution feeders. Switching in a capacitor bank reduces the amount of reactive power that would otherwise be supplied by the central generators via the transmission system. This reduces the current flow on both the transmission and distribution systems and, as a result, reduces the nontechnical losses given by the formula I^2R . Figure 3.5 illustrates how switched capacitor banks can help reduce the current flow and the associated heating losses on an electric distribution system. As an example,

improving the power factor from an average of 0.80 to near unity would reduce nontechnical losses by approximately 36 percent.

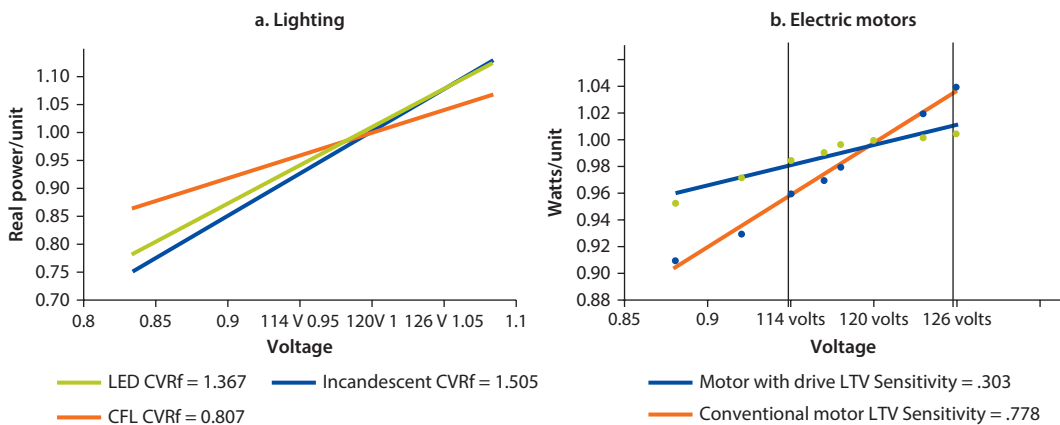
Many utilities are considering conservation voltage reduction (CVR), which is the intentional lowering of voltage to the lower portion of the acceptable range of service-delivery voltage. Experience has shown that many appliances use less electricity with slightly reduced voltage. Figure 3.6 shows the impact of voltage reduction on various types of lighting and electric motors. As seen in the figure, the electric power consumed by an incandescent light bulb is reduced by 1.505 percent for every 1 percent of voltage reduction. Energy consumed by a typical electric motor can be reduced by .778 percent via a 1 percent voltage reduction.

Figure 3.5 Reducing Technical Losses with Switched Capacitor Banks



Source: World Bank.

Figure 3.6 Reducing the Voltage to Improve Efficiency

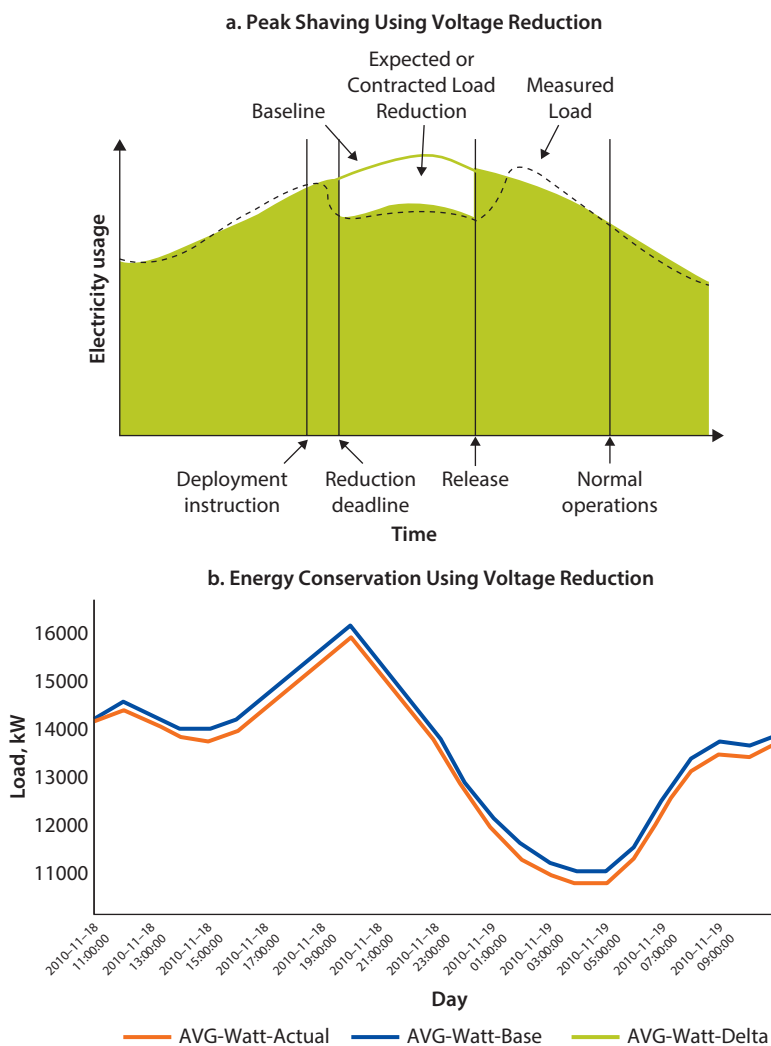


Source: World Bank.

Note: LED = light-emitting diode; CVRf = conservation voltage reduction factor; CFL = compact fluorescent lamp; LTV = load to voltage.

Electric utilities have used voltage reduction for many years during temporary power shortages, such as loss of a major generating facility during a heavy load period. Distribution utilities are now considering activating CVR in nonemergency situations to reduce demand during peak-load periods, and some utilities are considering running at reduced voltage around the clock to improve overall energy efficiency. Typically, electric utilities have been able to achieve between 2 percent and 3 percent energy reduction by deploying conservation voltage reduction on their distribution system. Figure 3.7 shows the use of voltage reduction for peak shaving at one electric distribution utility.

Figure 3.7 Energy Conservation and Peak Shaving Using Voltage Reduction



Numerous utilities have demonstrated that CVR is a very effective energy efficiency tool that does not adversely affect electricity consumers. But the industry has learned that voltage reduction does not produce the same benefits on all circuits. Some feeders show significant efficiency improvement when voltage is reduced, while others exhibit a less prominent effect due to differences in load mix and circuit characteristics. Leading research institutions such as the Electric Power Research Institute (EPRI), Pacific Northwest National Labs (PNNL), and National Electric Energy Testing Research and Applications Center (NEETRAC) are developing ways to predict CVR behavior so that utilities can prioritize their VVO investments.

Intelligent Line Switching

Electric utilities are giving particular attention to reliability improvement and the “self-healing” grid. There have been numerous developments in the areas of fault anticipation (detection of equipment problems before faults occur) and fault location. When actual faults occur, electric utilities are able to identify fault location with much improved precision using information from substation protective relay IEDs, FCIs, outage management systems, and short circuit models. These new fault-locating facilities will enable utilities to locate permanent faults as well as recurring temporary faults that have not yet caused an extended outage.

Many utilities are implementing systems that automatically detect faults, isolate the damaged portion of the feeder, and restore as much service as possible within seconds as part of their strategy to achieve a “self-healing” grid. Figure 3.8 illustrates the “self-healing” actions by comparing grid status before and after an event. One problem with current FLISR systems is that service restoration is often blocked due to heavy loading on backup feeders. The next generation of automatic restoration systems should take advantage of other advanced control facilities that are being deployed as part of the smart grid. For example, when encountering a load transfer limit, the automatic restoration system may initiate actions to free up capacity on the affected feeders, thus enabling the load transfer to proceed. Capacity release strategies may include initiation of demand response actions, activation of CVR, and temporary reduction of fast charging activities for electric vehicles.

Figure 3.8 Automatic Service Restoration (FLISR)



Source: World Bank.

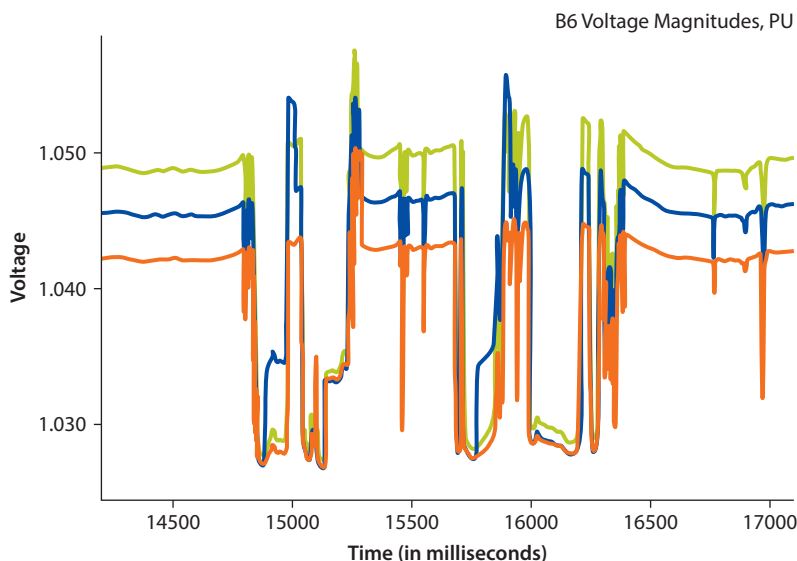
Outage Management Systems

One of the key systems in the modern control center is the outage management system (OMS), which assists the electric distribution system operator in detecting feeder outages, determining the approximate location of the root cause of the outage, dispatching field crews, estimating the expected restoration time, tracking damage assessment and restoration activities, and developing outage statistics (System Average Interruption Duration Index, System Average Interruption Frequency Index, and so on). Traditionally, an electric utility response is triggered by the receipt of telephone calls from customers whose electric power is off. The modern OMS will also accept inputs from advanced customer meters that are capable of detecting and reporting local power outages and from distribution SCADA facilities. Upon receipt of such outage indications, the OMS will use the “as-operated” model of the distribution system to group-related pieces of outage information and predict the approximate location of the expected fault. This information is sent to field crews (first responders) to begin the outage restoration process.

Management of Distributed Energy Resources

Increasing penetration of customer-owned generation sources, especially highly variable “renewables” (such as wind and solar power), have added a high degree of uncertainty (unpredictability) to the day-to-day, hour-to-hour operation of the distribution system. These distributed generating resources can dramatically alter the flow of power and the voltage profile along the feeder in a manner that is sometimes difficult to predict. Changes to existing protection systems and voltage regulation facilities are needed to ensure that such power fluctuations do not result in unacceptable service levels for distribution customers or cause a potential safety hazard for field crews.

The complexity of integrating solar electric and wind power into the electric distribution system is primarily due to the variable nature of these generating sources. The output of these renewable generating sources rises and falls with passing clouds and changes in wind speed. When clouds block the sunlight, the output of solar photovoltaic (PV) units is reduced, and more power must instantaneously be drawn from the electric utility substation to make up for the lost solar generation. This additional power drawn from the substation results in an additional voltage drop along the feeder, and customers will momentarily experience lower voltage. After a short (intentional) delay, conventional voltage regulators and load tap changers at the substation will operate to restore normal voltage on the feeder. When bright sunlight returns, the process is reversed and customers momentarily experience higher than normal voltage until voltage regulators and load tap changers make the necessary voltage adjustments. With high penetration of renewables, the voltage variations will cause “flickering lights” and will also impose significant wear and tear on expensive voltage-regulating equipment. Figure 3.9 illustrates the types of voltage fluctuations that can be experienced on

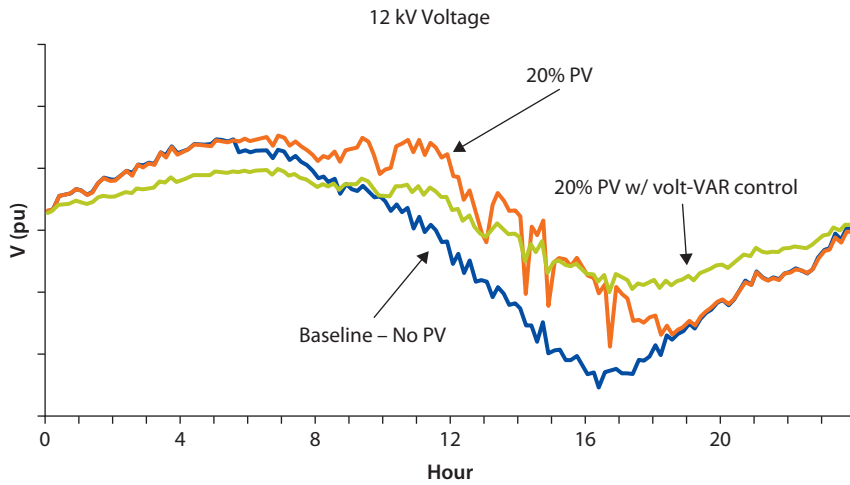
Figure 3.9 Dynamic Voltage Fluctuations Caused by Solar PV

Source: Dugan 2012.

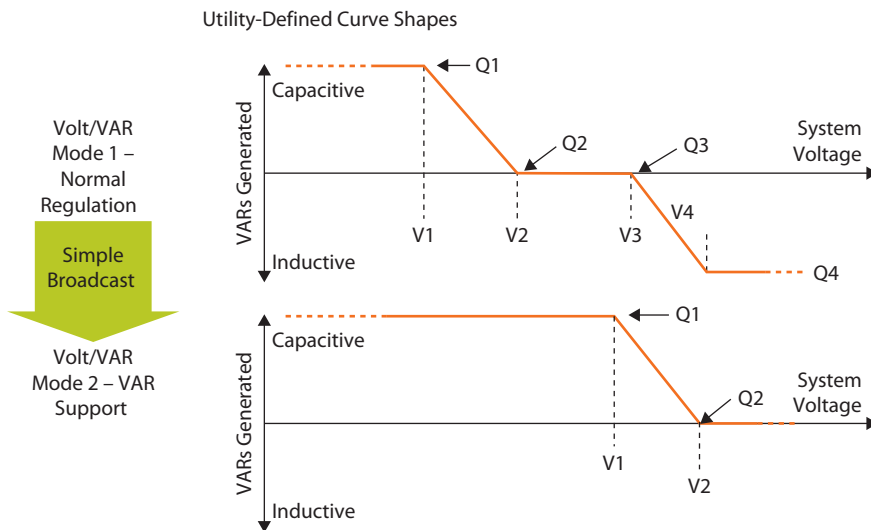
the distribution feeders during power output fluctuations from a large concentration of solar PV units and resulting voltage corrective actions by voltage regulators. Large voltage drops (as shown in the figure) occur when cloud cover causes a large drop-off of solar PV output, and voltage increases occur when solar PV output is restored or corrective actions by voltage regulators occur.

To minimize the magnitude of the voltage variations, electric distribution utilities have limited the total amount of renewable generating sources that can be connected to a given feeder. This is at best a temporary solution to the problem. To accommodate greater amounts of renewable generation, the distribution system of the future must include new fast-acting (high-speed) controls that can mitigate load and voltage fluctuations without tight constraints on the amount of generation that may be connected to the distribution system. Figure 3.10 shows voltage fluctuation over time with and without high penetrations of solar PV existing on the feeder. The figure also shows how voltage fluctuations can be reduced by deploying fast-acting controls to counteract these voltage fluctuations.

The electric utility industry is currently demonstrating advanced control capabilities, such as using alternating current on each renewable generator, to mitigate the consequences of load and voltage fluctuations. For example, the next generation of smart AC inverters can include a volt/VAR operating characteristic similar to that shown in figure 3.11. When sudden changes in renewable power output occur, the smart AC inverter can detect this situation and rapidly inject reactive power (VAR)

Figure 3.10 Voltage Fluctuations Associated with Solar PV

Source: Dugan 2012.

Figure 3.11 Volt/VAR Characteristic of a Smart Inverter

Source: EPRI 2012.

to compensate for the loss of real power output. This will mitigate the voltage swings and reduce the operating duty on conventional voltage-regulating devices. While such control actions by smart AC inverters will be instantaneous and autonomous, the specific control actions that are needed at any given time may vary with current power grid conditions and feeder configuration.

Demand Response

Demand response (DR) involves a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy. DR refers to the ability of customers to respond to either a reliability trigger or a price trigger from their utility system operator, load-serving entity, regional transmission organization/independent system operator (RTO/ISO), or other DR provider by lowering their power consumption.

Electric utilities in many countries are considering DR as an effective alternative to adding new generation and power delivery facilities. That is, utilities are seeking to reduce the demand during peak-load periods rather than build new generators and power delivery facilities to meet rising loads. DR requires effective mechanisms to initiate DR control actions when needed and verify that the requested DR activities have been performed.

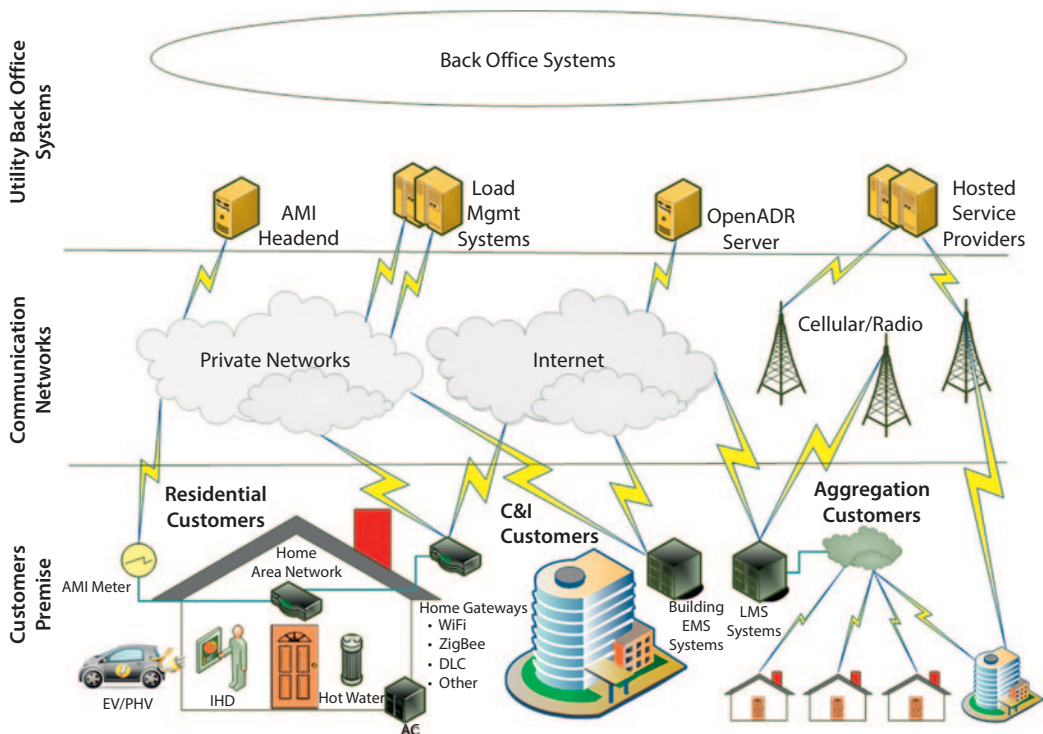
Some DR programs signal the customer via a text message, e-mail, or in-home display (IHD) that demand reduction is needed, and leave it to the customer to voluntarily reduce consumption in return for a pricing incentive. In such cases, an effective mechanism is needed to determine that the customer did indeed reduce consumption in response to the signal. Other DR systems directly control end-use appliances via direct on-off controls, programmable thermostats, and other devices to achieve the desired demand reduction. Figure 3.12 is a conceptual diagram of a typical DR system.

Data Analytics for Managing “Big Data”

The addition of advanced metering infrastructure (AMI) and many new intelligent sensors has enabled electric distribution utilities to acquire a wealth of new information about the performance of its assets. To make such information useful, modern database management and mining tools will be required. As noted in chapter 2, *data analytics* is the application of computer technologies and statistical models to enable electric utilities to make more effective decisions by transforming (often large and complex) data into actionable intelligence.

Data analytics software is generally able to extract considerable value from advanced metering data in the following areas:

- *Revenue protection*: Theft detection and case support
- *Meter operations*: Defective meter identification and historical repository
- *Care center*: High bill inquiries
- *Billing*: Estimation support
- *Distribution operations and planning*: Transformer load management, overload protection and device sizing, improved system planning, and project prioritization

Figure 3.12 Demand Response Management System

Source: Triplett 2012.

Note: AMI = advanced metering infrastructure; IHD = in-home display; DLC = direct load control.

- *Energy acquisition:* Load forecasting
- *Finance:* Unbilled sales reporting, sales and revenue forecasting
- *Energy efficiency:* Demand response and efficiency targeting, customer usage reporting, data for evaluation and cost recovery.

Interval load data from advanced meters can be aggregated to provide a granular view of loading conditions at any point along a feeder. Load data can be analyzed to target customers for demand response to reduce peak loading on distribution transformers. Data analytics can be used to target customers for programs based on individual load characteristics and housing data (for example, peak day kWh/square foot). Data analytics can also be used to measure program impacts and calculate incentives for performance-based programs (for example, DR). AMI/automatic meter reading (AMR) data results can also be used to support regulatory evaluation and cost-recovery.

Both near-real-time and historic information on power outages can be derived using a meter's "last gasp" events and "power out" logs, respectfully, including outage count and duration. Outage analytics can be used to identify

and verify all customers with an extended outage following a storm. Data analytics can also be used to validate real system outages (indicated by protective relay information and significant changes in consumption) versus false meter outages. Outage data analytics can also be used to screen for an increasing frequency of momentary outages at or near a given location, which possibly indicates a potential reliability issue.

Voltage analytics can identify meters whose voltage varies notably from those of other customers on the same transformer, indicating either power quality or customer diversion issues. Power quality issues due to low voltage can be measured directly over time rather than derived through load-flow modeling.

Geospatial data can be used to improve the connectivity of distribution system models. Outliers to a geospatial grouping (such as a customer that is assigned to the incorrect transformer) can be identified with an algorithm.

Networking in the Smart Grid

This chapter provides an overview of a standardized approach to the architectural design of communications systems or an upgrade of an existing communications system for electric power systems.

The variety of proprietary protocols with custom communications links from various vendors made it difficult for automation devices deployed in electric power systems to communicate or “interoperate” effectively. To solve this problem, the International Electrotechnical Commission (IEC) 61850 standard was developed so that electric utilities and vendors of electronic equipment could produce standardized communications systems. IEC 61850 contains standards for client/server and peer-to-peer communications, substation design and configuration, and testing.

High-speed switched Ethernet networks that are based on the IEC 61850 standard in electric power substations and distribution systems support the following:

- Supervisory control and data acquisition (SCADA) communications.
- Engineering access and asset management.
- Peer-to-peer communications for high-speed, mission-critical protection and control applications.

Communications-assisted protection and control schemes, as well as automation designs, require an understanding of the applied data transmission media and protocols in order to be used correctly to accelerate the execution of the underlying applications.

The IEC 61850 standard describes the behavior of intelligent electronic devices (IEDs) in networks and provides specifications on IED communications methods.

Design and specification of a communications system based on IEC 61850 protocols and methods require the use of many other standards, as shown in Table 4.1.

Table 4.1 International Standards That Are Used to Design Systems Based on IEC 61850

<i>International standard</i>	<i>Purpose</i>
IEC 61850	To define various message performance classes that provide guidelines for transmission times of digital messages to satisfy specific applications.
IEC 60834	To identify maximum transmission latencies and scientific measures of dependability and security to support mission critical applications.
IEC 60870 IEEE 1613	To identify scientific measures of device and system reliability and maintainability.
IEC 15802 IEEE 802.1	To identify Ethernet frame construction guidelines for efficient message transfer through the Ethernet network.

System design is based on understanding and mitigating the potential impacts to the latency and determinism (described in subsequent sections) of the messaging in order to predict and remove as much risk of failure as possible.

- Understanding all the factors involved in the transport or transmission of multiple message classes across networks and how the factors affect message determinism is critical for creating robust communications-assisted applications.
- Different IEC 61850 message classes require specific criteria for determinism, message delivery, and availability.
- Communications designs must account for these factors in order to satisfy application requirements.
- Message transport through the network must be able to meet application requirements for delivery and availability across all anticipated conditions.

IEC 61850 describes engineering design methods, data mapping, and communications methods to support several of the application requirements in an IED network, including those shown in table 4.2.

However, in order to build feature-rich systems, the IEC 61850 standard also describes the use of Ethernet. By using Ethernet, an IEC 61850-based system also supports other compatible Ethernet-based protocols on the same network. Complementary Ethernet-based protocols, such as those shown in table 4.3, coexist in the IEDs and on the network with IEC 61850 protocols. In this way, the Ethernet network supports all necessary communications applications including those not yet supported by IEC 61850 protocols.

Table 4.2 IEC 61850 Engineering Design Methods, Data Mapping, and Communications Methods

<i>Method</i>	<i>Mechanism</i>
IED self description	Via MMS (manufacturing messaging specification)
Communications configuration	Via MMS
Client data requests	Via MMS
Server data reports	Via MMS
Client commanded control	Via MMS
Sampled values (SV)	Via GOOSE (generic object oriented substation event) and 9-2LE (SV)
Peer-to-peer multicast	Via GOOSE
Time synchronization	Via GPS IRIG methods, SNTP (Simple Network Time Protocol), PTP (Precision Time Protocol)
File transfer	Via MMS
Engineering access	Via MMS
Synchrophasors	Via MMS, GOOSE, 9-2LE SV

Table 4.3 Protocols That Coexist with IEC 61850

<i>Protocol</i>	<i>Mechanism</i>
IED self description	Via MMS and Telnet, Fast Message Interleave (FMI)
Communications configuration	Via MMS and Telnet, FTP, FMI, web server
Client data requests	Via MMS and Telnet, FMI, IEEE 1815
Server data reports	Via MMS and Telnet, FMI, IEEE 1815
Client commanded control	Via MMS and Telnet, FMI, IEEE 1815
Sampled values	Via GOOSE, 9-2LE SV
Peer-to-peer multicast	Via GOOSE Messages and MIRRORED BITS Communications*
Time synchronization	Via GPS methods, SNTP and PTP
File transfer	Via MMS and Telnet, FTP, FMI
Engineering access	Via MMS and Telnet, FTP, web server
Synchrophasors	Via GOOSE, 9-2LE SV, IEEE C37.118

*MIRRORED BITS communications is a relay-to-relay communications technology patented by Schweitzer Engineering Laboratories, Inc. (SEL) that exchanges the status of eight internal logic points called MIRRORED BITS, encoded in a digital message, from one device to another. This technology opens the door to numerous protection, control, and monitoring applications that would otherwise require more expensive external communications equipment wired through contacts and control inputs.

Complete system automation, however, requires additional communications applications that are not addressed by the IEC 61850 standard and that are typically accomplished with other compatible methods, such as those shown in table 4.4.

Table 4.4 Protocols That Are Compatible with IEC 61850

<i>Protocol</i>	<i>Mechanism</i>
Unsolicited notification of events	Via FTP, Telnet, FMI, MMS Reporting email
Configuration revision management	Via FTP, Telnet, FMI, MMS
Alarm callout and call back	Via Telnet, FMI, web servers
Communications diagnostics	Via Telnet, FTP, FMI, web servers, MMS
Performance analysis	Via Telnet, FTP, FMI, web servers, MMS
Virtual backplane high speed data bus	Via Ethercat

Determinism of Message Streams

Deterministic communication is the ability to consistently transfer data packets across a specified communications channel with predictable end-to-end variation. The variation between packets is called jitter or packet delay variation. Ethernet packet latency is the time duration between the publication and delivery of a packet through a network. The communication-assisted protection and automation functions require low latency and deterministic packet delivery to adequately use digital messaging to convey protection signals that were formerly conveyed via hardwired connections.

Time division multiplexing (TDM) is one protocol that provides a high level of determinism of message streams over a physically private network (PPN), such as direct serial or Ethernet cables and multiplexer ePipe Ethernet circuit connections, which provide their entire bandwidth for a single purpose or path.

The benefit of not sharing bandwidth is that these methods provide time-deterministic message delivery without interference or saturation from other unwanted messages, and they are able to meet specific performance criteria better.

Switched Ethernet is deployed via a connection to an intermediary Ethernet switch instead of directly to a single subscribing device in order to support numerous data paths and multiple subscribing devices. Switched Ethernet communications is based on dividing message streams into multiple packets to share the network bandwidth better. Therefore, it involves receiving, buffering, prioritizing, and forwarding messages within the network.

This makes its applications for protection and control inadequate for mission-critical protection functions, such as tripping, interlocking, or sending permissive or blocking signals. The Ethernet system design must satisfy the determinism requirements for the network-supporting substation protection and control schemes.

Consider the situation of a simple bus-blocking scheme. Good system design anticipates the following questions when a blocking signal sent over Ethernet is being considered:

- How should the coordinating timer be set?
- What is the worst case message delivery time, given the network design?
- How do we ensure that this time does not change with network expansion or upgrades?
- How do we test for this worst case message delivery time?
- Is the message delivery jitter acceptable to meet the application requirements?

These questions must have measurable and deterministic answers for communications engineers and protection engineers.

IEC 61850 standardizes the data flow aspects of automation systems to perform many of the required substation communications applications.

In addition, the goals of IEC 61850 communications standardization are to create an internationally recognized method of supporting the interoperability of products between multiple manufacturers and multiple product lines of individual manufacturers for retrofitted and new systems, as well as future additions to existing systems.

As a standard, IEC 61850 describes new names, engineering processes, and communications methods to replace existing technology. Compatible protocols and methods must coexist on the Ethernet network with IEC61850-based protocols in order to accomplish the following:

- Communications performance.
- Reliability-centered maintenance.
- Asset management.
- Configuration revision management.
- Substation automation functions.
- Cybersecurity.

The IEC standard refers to important and necessary elements of system automation that are not addressed by the standard. These are “local issues,” meaning that they are left to the local integrator or manufacturer to address.

These local issues are addressed by accompanying standards and best practices, some of which are also described in this document. Knowledge of IEC 61850 is necessary for understanding and supporting the behavior of networked IEDs, although knowledge of the local issues guided by experience with the companion international standards is essential to effective system design that is compatible with IEC 61850.

IEC 61850 Interoperability

Interoperability is the capability of the two or more IEDs of the same or different supplier to exchange information and use this information to properly execute the specific functions (IEC 61850-1). This is accomplished through standardized communications techniques and the ability to send and receive standardized messages.

Even though devices are expected to be interoperable if they conform to the same standard, industry experience with other standard protocols proves that different development teams may create conforming, but non-interoperable, devices.

One way to improve the chances of interoperability is to choose devices that are all created by the same development group. However, the best method to assure interoperability is to test and observe it. To test every interoperability permutation as recommended by the standard is quite challenging. However, specific scenarios can and should be tested prior to product selection. If this information is not available to the end user for their intended application, it will be necessary for the end user to arrange for the proper testing to be done.

It is necessary to understand the interoperability requirements among IEDs and applications for the final design to function properly and to verify that this interoperability has been demonstrated or to arrange for it to be demonstrated. Therefore, the IEDs to be used must be tested by the user to be interoperable with other manufacturers' devices, so that even if the initial design is from a single manufacturer, there is confidence that devices from other manufacturers can be added in the future. Interoperability testing typically happens during a factory acceptance test (FAT).

The purpose of this conformance testing is to reduce the risk of failed interoperability between devices when put in service. However, the standard addresses a huge amount of communications scenarios and data models, of which only a subset will be implemented within any specific physical device or client. Therefore, vendors will typically only publish those elements of the standard to which their products have been tested for conformance.

In order to be considered interoperable by the end-user, each device will need to support the appropriate data and services. Vendors intend to use the method outlined by the standard in which they identify the data and services supported within the device, as well as the method that has been proved to conform to the standard. According to the IEC 61850 standard, vendors must state implementation conformance, which includes the level of support for the following services:

- Basic Exchange.
- Data Sets.

- Unbuffered Reporting.
- Buffered Reporting.
- GOOSE Publish.
- GOOSE Subscribe.
- Direct Control.
- Enhanced Direct Control.
- Enhanced SBO Control.
- Time Synch via global positioning systems (GPSs) or Network Time Protocol (NTP).

Over time the GPS description was understood to support IRIG-B (inter-range instrumentation group time code), and new Ethernet-based precision time protocol (PTP) methods are being developed. However, the IEC 61850 standard also recognizes that the functionality of an IED, although out of scope, is supremely important (IEC 61850; part 5). It refers to the requirements that IED reactions must satisfy desired functionality, and IED functionality must perform even during communications degradation.

Local Issues

Local issues refer to design specifications that must be understood and requested by the system owner based on the individual primary power system component and required performance. A number of important local issues are not addressed by the IEC 61850 standard. For these and other details, the IEC 61850 communications standard is designed to refer to and rely on other international standards to fully describe system requirements. Some of the standards used to specify some of these local issues around Ethernet-based, communications-assisted protection and automation systems are listed in table 4.5. Local issues not addressed by the IEC 61850 standard are dealt with locally in the IED by the developer, in the substation by the user, or a combination of the two.

Table 4.5 Standards Used to Specify Ethernet-Based, Communications-Assisted Protection and Automation Systems

<i>Standards</i>	<i>Type of specification</i>
IEC 61850, IEC 60834, ISO / IEC 15802, IEEE 802.1	System communication performance requirements
IEC 61850, IEC 60834, ISO / IEC 15802, IEEE 802.1	Latency specifications
IEC 61850	System message speed
IEC 61850, IEC 60834	Dependability and security requirements
IEC 61850, IEC 60834, IEEE 802.1	Availability requirements
IEC 61850, IEEE 1613, IEC 60870	Reliability metrics

These local issues are the description of the functionality that is required from the system and that clarifies the IED requirements that are necessary in addition to “IEC 61850 Compliance.”

Local issues are not documented, and in addition to that, not every contingency has been identified or standardized within IEC 61850. Much useful system information in the IEDs is not represented in standardized object models, such as asset management; diagnostics; reports; settings; notifications; and performance indicators. However, they are often provided using customized object models created by vendors following the IEC 61850 modeling rules.

Adding to the complexity of completing a substation automation system (SAS) is that many other important aspects remain outside the scope of IEC 61850, including the following:

- Method of designing, creating, and installing internal IED automation and protection.
- Process for all aspects of engineering access.
- Application functionality of devices, as well as performance characteristics of these applications. For example, it is possible, but perhaps not advisable, to interchange a relay with one that operates much more slowly to detect and operate on a fault.
- Method of installing IED IEC 61850 configurations.
- Methods of IED, system, and network analysis and diagnosis.

It is essential that IEDs not only conform to the functionality of the data flow described by the IEC 61850 standard, but that they also conform to local issues essential to building a system based on IEC 61850.

Performance Criteria for SAS and DAS under IEC 61850

As SASs and distribution automation systems (DASs) are connected to remote SCADA systems, even more local issues arise. This is because most SCADA masters in the past rely on legacy non-IEC 61850 protocols. These legacy protocols generally use simple data types that do not translate into more complex 61850 data types. Mandatory 61850 attributes are often not available via SCADA protocols, such as quality; time; control origin; and activation.

Other non-mandatory details describe the IED functional capabilities that are necessary to satisfy system performance requirements. These details include the following:

- Real time message sequence number, state number, and time to live values.
- Real time display of message configuration including dataset name, virtual LAN (VLAN), destination MAC, GOOSE ID.

- Real time display of message received statistics including messages received out of sequence, maximum consecutive messages not received, total aggregate messages not received, number of corrupted messages received, priority, and VLAN.
- Real time display of accumulated communication channel downtime duration, maximum communication channel downtime duration with precise date and time, number of time to live violations detected.

Although they are not yet mandatory for IEC 61850 conformance, they are necessary to satisfy integrated communications.

Message Requirements under IEC 61850

The IEC 61850 standard refers to the use of Type 1A message with Performance Class P2/P3 and is defined to have a transfer time requirement of fewer than 3 milliseconds as illustrated in figure 4.1. A Type 1A message is defined for Trip applications such as a communications-assisted tripping scheme.

IEC 60834-1 requirements for security, reliability, and dependability are met if the system meets the 3-millisecond transfer time 99.9999 percent of the time and has a delay no longer than 18 milliseconds for the remainder.

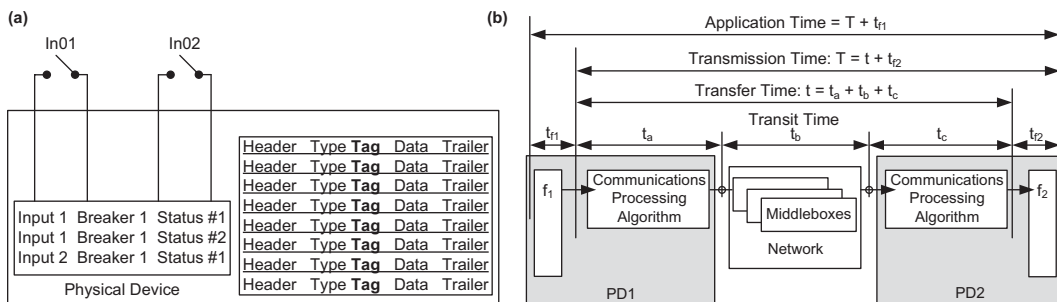
The IEC/TR 61850-90-4 network engineering guidelines for IEC 61850 Ethernet traffic suggest that GOOSE messages used for protection should be designed to have the highest priority and the shortest maximum delay. Control blocking schemes, via GOOSE messaging or any other method, require a 99.99 percent success rate, and direct control schemes require a 99.9999 percent success rate of the receipt of digital messages (reliability).

Direct tripping through delivery and processing of a GOOSE or other message is typically expected to occur within a transmission time of 20 milliseconds. Failure is defined by the absence of the message at the receiving end or, for direct control, a delay in delivery greater than 18 milliseconds. Therefore, the use of Class P2/P3 messages requires that the system be designed to meet the 3-millisecond transfer time.

This requires a high level of device reliability to keep the path failures to a minimum. System availability analysis based on IEC 61850-5 measures of reliability are used to predict the ability of each system to meet IEC 60834-1 dependability and security requirements. For example, a GOOSE application configured to publish confirmation messages every second publishes 86,400 messages every 24 hours.

Applying the IEC 60834-1 standard to a GOOSE signal exchange for direct tripping, as illustrated in figure 4.1 with a 1-second heartbeat requires that the network deliver every single GOOSE message packet, no exceptions (dependability), and deliver fewer than 9 unwanted GOOSE message packets (security) during every 24-hour period.

Figure 4.1 IED Contact Input Information Mapped as (a) Payload Data in GOOSE Messages and (b) Application, Transmission, Transfer, and Transit Time Based on IEC 61850-5



Source: Schweitzer Engineering Laboratories.

In summary, the systems need to support the following performance criteria:

- Signal < 3 msec, packet transit < 1 msec 99.99% of the time.
- Signal < 18 msec with transit < 15 msec remaining 0.01%.
- Zero dropped GOOSE, < 9 extra messages every 24 hours.

Systems made from networked IEDs need to be IEC 61850 conformant and must support the following performance criteria:

- *Immediate delivery by source, delivery by network, and reaction by destinations to received GOOSE messages.* (IEC 61850, IEEE 60834)
- *Message delivery speed.* Each mission-critical operational technology (OT) machine-to-machine, peer-to-peer multicast message defined as IEC 61850 Performance Class 2 or 3 needs to be delivered in fewer than 3 milliseconds, regardless of quantity, frequency, or network configuration. (IEC 61850)
- *Performance requirements.* OT applications are generally time-critical, with the criterion for acceptable levels of delay and jitter dictated by the individual installation. Protection class systems require deterministic responses in fewer than 3 milliseconds 99.99 percent of the time, regardless of distance, with never more latency than 18 milliseconds. (IEC 61850, IEC 60834, IEC 15802, IEEE 802.1)
- *Goodput ratio.* Goodput is the amount of useful data, user data, or payload that can be processed by, passed through, or otherwise put through a system and received at the correct destination address. It is actually application information throughput, a measure of the amount of information exchanged between devices participating in an application, as opposed to traditional communications message throughput. Goodput is a ratio of the delivered amount of information and the total delivery time minus any packet headers or other overhead and minus any information lost or corrupted in transit.

The system must include demonstration of a high goodput data set, message, and Ethernet network design. (IEC 61850)

- *Message delivery latency.* Permissible latency referenced by the IEC 60834-1 standard, which describes performance requirements for teleprotection systems within the smart grid, includes 15-millisecond maximum message delivery latency, 20-millisecond application latency for the permissive tripping teleprotection function and 25-millisecond maximum message delivery latency, 30-millisecond application latency for direct tripping. (IEC 61850, IEC 60834, IEC 15802, IEEE 802.1)
- *Message delivery security.* Security defined by IEC 60834-1 indicates the acceptable number of unwanted messages because they may cause unwanted operations, as illustrated in table 4.6. For a GOOSE exchange between devices with a heartbeat message sent once a second and signal status sent immediately after change of state to support the inter-tripping teleprotection function, the requirement is that each IED should receive fewer than 9 unwanted messages in a 24-hour period. Therefore, each source IED must deliver no unwanted GOOSE messages. (IEC 61850, IEC 60834)
- *Message delivery dependability.* Dependability defined by IEC 60834-1 indicates the acceptable number of delayed or dropped messages because they may prohibit communications-assisted operations, as illustrated in Table 4.6. For a GOOSE exchange between devices with a heartbeat message sent once a second and signal status sent immediately after change of state to support intertripping, the dependability requirement is that the Ethernet network should delay or drop fewer than one (essentially zero) messages to each IED every 365 days. (IEC 61850, IEC 60834)

Table 4.6 Security and Dependability Requirements of Digital Messages Exchanging Protection Signal Information Based on IEC-60834

COMMUNICATIONS-ASSISTED PROTECTION SCHEME (86,400 GOOSE per 24 hrs)	SECURITY Refrain from tripping breaker when not required to trip		DEPENDABILITY Perform breaker trip when required—NO EXCEPTIONS	
	P_{uc} (Probability unwanted command)	Number of allowed unneeded messages per 24 hrs	P_{mc} (Probability missed command)	Number of allowed delayed messages per 24 hrs
BLOCKING	$<10^{-3}$	<86	$<10^{-4}$	<9
INTERTRIPPING	$<10^{-4}$	<9	$<10^{-8}$	<1

Source: Schweitzer Engineering Laboratories.

- *Availability requirements.* Many OT processes are continuous in nature. Unexpected outages of systems that control industrial processes are not acceptable. Outages often must be planned and scheduled days or weeks in advance. Exhaustive predeployment testing is essential to ensure high availability for

OT. Also, many control systems cannot be easily stopped and started without affecting production. In some cases, the products being produced or equipment being used are more important than the information being relayed.

Therefore, network outages must be resolved in a matter of a few milliseconds, and IED and switches must have a high mean time between failures (MTBF). High availability of IEDs and systems, verified through high MTBF based on observed field data, reduce the likelihood of a system fault. Also, fast detection and isolation of a fault and fast data path reconfiguration and re-establishment of data communications are essential for appropriate failover or reconfiguration if a system fault should occur. (IEC 61850, IEC 60834, IEEE 802.1)

- *Risk management requirements.* For an OT system, the primary concerns are human safety and fault tolerance to prevent loss of life or endangerment of public health or confidence, regulatory compliance, loss of equipment, loss of intellectual property. The personnel responsible for operating, securing, and maintaining OT must understand the important link between safety and security. Products and systems must meet NERC PRC-005 (or any other relevant or equivalent national standard), IEEE 1613, and IEC 61850 reliability requirements. The system must be isolated from IT connections via a security gateway acting as a demarcation point between IT and OT. (NERC PRC-005, IEEE 1613, and IEC 61850)
- *Architecture security focus.* For OT, IEDs, such as protective relays, programmable logic controllers (PLC), operator stations, and distributed control system controllers, need to be carefully protected because they are directly responsible for controlling the end processes. The protection of the central server is also very important in an OT system because the central server could possibly adversely impact every edge device.¹ Routers, switches, and multiplexers use OT routing information within the network layer addressing to route messages. When positioned at the intersection of OT and IT networks, these devices act as intersection devices. Routers, switches, and multiplexers are edge devices that must satisfy OT and act as a perimeter intersection demarcation device. (NERC PRC-005 or any relevant or equivalent national standard, IEEE 1613)
- *Physical interaction.* OT networks have very complex interactions with physical processes and consequences in the OT domain that can be manifested in physical events. All security functions integrated into OT must be tested offline on comparable OT to prove that they do not compromise normal OT functionality. The required environmental ruggedness and reliability of communications networking devices installed in OT networks are dictated by standards such as IEEE 1613. All IEDs, including edge devices, must meet stringent temperature, electric shock and noise, and vibration survivability standards. (NERC PRC-005, IEEE 1613, and IEC 61850)

- *Time-critical responses.* In OT, automated response time or system response to human interaction is very critical. For example, requiring password authentication and authorization on a human-machine interface (HMI) must not hamper or interfere with emergency actions for OT. Information flow must not be interrupted or compromised. Access to these systems should be restricted by rigorous physical security controls.(NERC PRC-005, IEEE 1613, and IEC 61850)
- *System operation.* OT operating systems and applications do not tolerate typical IT security practices. Legacy systems are especially vulnerable to resource unavailability and timing disruptions. Control networks are often more complex and require a different level of engineering expertise (for example, control networks are typically managed by control engineers, not IT personnel). Software and hardware are more difficult to upgrade in an operational control system network. Demarcation devices must support encryption capabilities, error logging, and password protection.(NERC PRC-005, IEEE 1613, and IEC 61850)
- *Change management.* Performing, documenting, and archiving configuration, software, and firmware changes are paramount to maintaining the integrity of both IT and OT systems. Unpatched software represents one of the greatest vulnerabilities in a system. Software updates on IT systems, including security patches, are typically applied in a timely fashion based on appropriate security policies and procedures. In addition, these procedures are often automated using server-based tools because their potentially negative impact on network and device availability is considered acceptable. Software updates on OT cannot always be implemented on a timely basis because these updates need to be thoroughly tested by the manufacturer of the industrial control application and the end user of the application before being implemented. OT outages often must be planned and scheduled days or weeks in advance. The OT system may also require revalidation as part of the update process. Another issue is that many OT systems use older versions of operating systems that are no longer supported by the manufacturer. Consequently, available patches may not be applicable. Change management is also applicable to hardware and firmware. The change management process must be performed by OT staff and requires infrequent patches and upgrades. The system must be designed with contingencies for continued operation during change management maintenance.(NERC PRC-005, IEEE 1613, and IEC 61850)
- *Component lifetime.* Typical IT components have a lifetime of 3–5 years, with the brevity resulting from the quick evolution of technology. For OT, where technology has been developed, in many cases, for very specific use and implementation, the lifetime of the deployed technology must be 20–30 years. (NERC PRC-005, IEEE 1613, and IEC 61850)

OT and modern IT networks need to be engineered, not simply assembled. IT experts need to be familiar with the following important facts:

- PCM IEDs are peripheral devices that are VLAN aware.
- PCM IEDs that manage IEEE 802.1 Q VLANs require a new category of switch connection for a peripheral device with more network control than an edge, such as VLAN management, but not all the features expected for a trunk.
- IEC 60834-1 defines latency, dependability, and security requirements.
- Protection-class application dependability and security require near-zero message loss, not buffer and resend.
- PCM networks have static configurations, device addressing, and limited multicast routing. Dynamic reconfiguration is not acceptable.
- Failure to address the root cause of Ethernet packet loss has burdened peripheral devices with numerous recovery processes.
- Every dropped packet is a near miss. Each near miss has the potential to overlap message delivery of a malfunction and delay prevention of a catastrophe.
- IT, OT, and PCM experts need to continue to collaborate on appropriate solutions for all applications.
- Failure and rerouting times between switches are interesting, but the critical measure is time to restore communications to the peripheral devices.

Wireless Local Area Networks (LANs)

Distribution automation systems often rely on wireless communications due to long distances between IEDs, remote installations, and cost constraints. Substation distribution automation controllers often need to communicate wirelessly to distribution pole mounted devices including recloser controls, capacitor bank controls, meters, and voltage regulators.

Modern radios have several serial or Ethernet ports that support different simultaneous connections and protocols. By using radio frequency (RF) synchronization technology, two radios are collocated to communicate back to back and exchange data as repeaters without interference.

The value and benefit of inexpensive and robust dual-ring communications among remote sites using this technology are that pairs of radios located at each site and connected through synchronization technology provide continuous peer-to-peer communications simultaneously in both directions around the ring. These radio pairs also support both a primary and failover SCADA link for constant data acquisition and control, even in the event of a single-point communications failure.

Many existing devices and applications use serial communications networks and protocols, such as DNP3 or Modbus®, to communicate between remote sites and a centralized SCADA system.

These client-server protocols support data acquisition and commanded control messages from the centralized SCADA client to the remote devices via SCADA radios at each site. This client-server polling scheme traditionally requires that the SCADA radio at the client communicate directly with each remote SCADA radio, one at a time. The protocols support data acquisition and control status responses from the remote sites back to the SCADA client over the same radio pair.

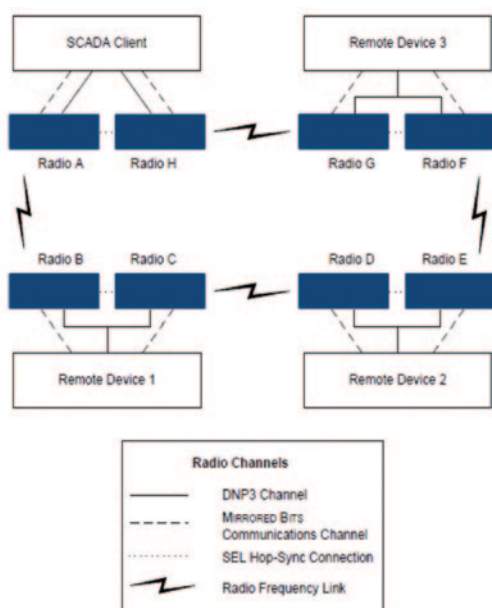
Because of the nature of these protocols, they cannot be used for bidirectional, high-speed automation and control purposes. High-speed, peer-to-peer, real-time data exchange requires one or more additional, separate communications paths for bidirectional monitoring and control.

Traditionally, this peer-to-peer application required a second pair of radios between sites, resulting in increased cost associated with installation and equipment, such as antennas, feedlines, and surge arrestors.

To address this issue, synchronized radios can be installed in a ring topology to enable reliable, bidirectional, high-speed communications for automation and control. These radios have several serial or Ethernet links multiplexed over one radio channel. Each port can be configured to communicate a different protocol.

These radios are installed in pairs at each site. The example in figure 4.2 represents a typical setup for a dual high-speed ring. In this example, one port is

Figure 4.2 Wireless Communications Ring Example



Source: Schweitzer Engineering Laboratories.

dedicated for SCADA control and monitoring using DNP3 protocol to an IED or remote device port.

A second port is used for inter-site, high-speed, peer-to-peer communications via MIRRORED BITS® communications or GOOSE to another IED port. These MIRRORED BITS communications or GOOSE links simultaneously transmit data in both directions between the radios.

Because IEDs have multiple ports that support peer-to-peer communications, data coming from one direction into a communications port are often passed through and published out of the second peer-to-peer communications port. In this way, the IEDs and radios perform high-speed data repeating.

In the case of radio repeater sites, a third port (Port 3) is interconnected between the local radio pair. It performs conventional repeating of the received protocol messages among radios without passing the messages through the IEDs. This is accomplished using directional antennas at repeater sites, which improves the link range because the antennas are more effective than the omni-directional antennas used in non-repeater applications.

The connection between the Port 3 of each radio also performs radio hopping synchronization for minimum interference between the radios. This synchronization allows two radios to synchronize publications, referred to as *hops*, to the next radio in the ring in order to prevent the radios from interfering with each other.

This configuration allows continuous bandwidth at a lower latency compared with using another separate radio as a repeater and attempting to communicate through simultaneous receipts and publications. This synchronized transmission minimizes the interference and maximizes the radio performance. In the ring topology, multiple channels between sites provide flexible topologies and allow the use of more than one protocol between the central SCADA system and remote sites, as well as between sites.

Advantages of Dual High-Speed Ring Topology in LANs

A ring topology enables bidirectional data flow between sites. This allows messages to travel around the ring in both directions to remote sites by being repeated at each site along the way. It also supports peer-to-peer messages between sites in both directions. The multiple ports on the radios support simultaneous peer-to-peer communications and SCADA protocols, such as DNP3, to multiple sites located far away from the central site. This simplifies site-to-site path studies, installation, and communications with sites that do not have a direct line-of-sight to the central site. The advantages of the dual high-speed ring topology include the following:

- The dual-ring topology supports redundant client-server connections to improve reliability. This feature is possible if the client device, such as a Real-Time Automation Controller (RTAC), supports dual primary interrogation ports. This provides data flow redundancy of SCADA protocols for more

reliable communications simultaneous with bidirectional peer-to-peer communications over the other channel.

- Every radio location has the ability to monitor SCADA and engineering access messages to and from every other site. Technicians can diagnose and troubleshoot communications problems from multiple locations.
- The data load between sites is shared over multiple channels for consistently enhanced performance of three separate IED communications channels. Due to its ruggedness, longevity, and ability to transmit and repeat both peer-to-peer and centralized data acquisition and control communications, the radio ring is a great fit for use in control and monitoring applications, especially for geographically distributed remote sites. Bidirectional data flow enables peer-to-peer data exchange to support rapid communications-assisted decision points at multiple remote sites. A dual high-speed ring used for control and monitoring applications improves automation system operation, performance, and reliability because it allows the following to be done:
 - Perform early detection of communications and process failures at each site and adjacent sites.
 - Create and store typical process data in order to permit future comparisons to detect abnormalities.
 - Use timely detection of abnormalities in the process to alert end users of channel failure and trigger condition-based maintenance.
 - Automatically react to data from any site to trigger fail-safe or preventative actions.
 - Improve troubleshooting and diagnostic calculations and reduce calculation time because data are shared between sites over multiple channels.
 - Improve operational efficiency by decreasing the application downtime, and improve processes with system-wide situational awareness.

Cybersecurity Policy for Utility Engineered Systems (ESs)

Cybersecurity has become increasingly important and requires a separate specification to work in a coordinated fashion with this communications specification. It is important to protect systems from threats posed by hackers, disgruntled employees, terrorists, and countries with sophisticated information warfare plans and capabilities. This is a specialized, fast-moving subject and, for this reason, IEC 61850 intentionally avoids describing encryption and authentication techniques and instead relies on other related standards to describe compatible methods. IEC 61850 protocols and methods do work with other technologies in communications network and IEDs to provide practical and forceful cybersecurity protection.

All parts of the utility are responsible for satisfying cybersecurity, but the real-time prevention of cyber intrusion rests in the substation and distribution communications network. In conjunction with a separate utility-wide cybersecurity policy, the substation and distribution communications network must quickly reduce the threats to vital power system assets.

The policy guidelines in the following section, summarized here, must be adhered to in order to maintain a consistent, high quality of service, along with a high level of security to protect confidential information and sensitive data. The cybersecurity design must ensure that the communication network delivers all published digital signals dependably and confidentially. It might also ensure that all unwanted digital access be identified, prevented, alarmed, and documented. General, recommended practices include the following:

- Disable all unused communications ports, including USB (Universal Serial Bus), to prevent unwanted access via cables and memory drives.
- Use and manage strong passwords. For example, strengthen a weak password, such as “Webster” by changing it to a stronger version, such as “W3b\$t3r.” Choose IEDs that do not use default passwords, and permit easy changes to passwords periodically and when an employee leaves. When possible, deploy a firewall that performs automatic and scheduled password changes.
- Secure communications with encryption and authentication tools.
- Use Media Access Control (MAC) filtering to allow maintenance access to only those tools and engineering workstations that are preauthorized.
- In a separate location, securely store all engineering computers, passwords, encryption equipment and keys, instruction manuals, and software.
- When possible, support more than one secure communications path.
- Use appropriate communications network design to minimize the likelihood and impact of a denial-of-service attack.
- Send security alarms through SCADA and a second path.
- Archive and review log files on firewalls, alarms, and access activity.
- Coordinate the communications network and cybersecurity with physical security via network IEDs with physical security I/O.
- Practice “security in depth.” Physical—Cyber—Communications—Training—Culture. Have a clear, concise, and well-thought-out plan in place beforehand about how your company will respond to a cyber incident.

Employees

Background checks and reference checks will be performed for prospective employees. Utility employment is contingent on successful completion of a drug test. Employees are subject to periodic, random, and for-cause drug testing. Utility ES repeats background checks for applicable employees before they complete seven years of service.

Training

All new employees will receive training on Utility security practices. In addition, Utility provides continuing security education to employees through regular training and security awareness sessions.

Physical Access Controls

Employees' physical access will be restricted to the locations and times needed for them to perform their jobs. An audit of all employees' access permissions may be performed on a routine basis. Utility will use multiple layers of defense in depth to ensure a secure work environment, as well as to aid forensic investigations.

Data Security Access Controls

Utility ES uses need-to-know principles in storing Utility and customer information. Electronic files are stored and secured using role-based access controls that the project administrator and supervisor maintain. Electronic files are stored on file systems that require authentication and control authorization. Employees who are no longer employed by the Utility are automatically removed from access to systems.

Security Policy for Customer Documentation

Employees will consider all information and documentation for customer systems to be confidential to the Utility. They are to dispose of old or outdated customer hardcopy information using appropriate measures, such as locked shredding bins provided by the Utility.

Security Policy for IT Controls on Customer Systems

Utility ES personnel will adhere to the Utility computer use policy and will use this policy to secure Utility ES customer information systems, such as servers and workstations.

Password Policy

Utility ES employees will use strong and non-default passwords on all systems that contain or transmit private information on the customer or sensitive information on the Utility. Passwords must be stored in encrypted vaults or stored in a physically secure location.

Systems and Change Management

Employees are required to submit a formal written change request for all system changes, both scheduled and unscheduled, to project management. Each change request must receive formal Utility ES security and network approval before employees may proceed with the change. Utility ES must have prior customer notification and approval for each change.

A change management log must be maintained for all changes. The log must contain the following information:

- Date of submission and date of change.
- Owner and custodian contact information.

- Nature of the change.
- Indication of success or failure signed by Utility ES and customer.

Data Protection in Transit and at Rest

Confidential and sensitive data must be stored and transferred using approved secure means. Critical data are to be stored on centralized network storage and systems. Utility laptops must run full-disk encryption, real-time anti-virus, and firewalls. Utility laptops are subject to centralized patch management. USB storage use is limited to business need and only with approved devices. Employees must use Utility's encrypted file transfer algorithm (FTA) to transfer files securely between Utility and outside sources. Standard email and FTP are not suitable for transferring confidential Utility data. Connection to internal Utility resources requires strong authentication through the use of a Utility virtual private network (VPN) or similar.

Non-electronic data must also be treated with similar care. Employees must keep confidential documents put away and must use locking cabinets if needed.

Examples of confidential or sensitive data include data labeled Utility Confidential, Utility Secret, or NERC CIP data, as well as customer drawings and configuration data, personally identifiable information, and credit card data.

Anti-Malware

Utility ES employees shall use defensive in-depth principles to protect against malware. All Utility employee systems shall follow the Utility Computer Use policy and have some active form of the following tools:

- AntiVirus/AntiMalware (Whitelist).
- Patch management.
- Client firewall.

Enterprise email is to be protected and scanned by a spam filter. Employees are to be protected from web-based malware by a web gateway. Finally, security monitoring solutions are in place to detect threats against clients.

Data Disposal

All confidential data shall be securely wiped or shredded when no longer needed. Hard drives, including those in computers, faxes, and printers must be securely wiped, degaussed, or destroyed. Solid state drives require destruction of encryption key or entire drive.

Disaster Recovery

Utility shall have a disaster recovery plan to address the continuation or recovery of business in the case of a serious event. Critical systems, including those that contain customer data, shall include disaster recovery plans and must be tested

prior to implementation. In addition to disaster recovery, systems must include appropriate redundancy and backups for the application.

Conclusion

Implementing a comprehensively engineered IEC 61850 solution is not a trivial task. Training is a primary issue that must be addressed, because the change in thinking is more revolutionary than evolutionary. Ethernet networks and multi-function devices have changed the processes and possibilities of system specification, design, construction, commissioning, testing, troubleshooting, and maintenance.

For many, the first experience with substation ethernet is for engineering access, which is neither time nor mission critical. Unfortunately, design practices for engineering access connectivity are not adequate for protection, control, and monitoring (PCM) communications. Therefore, networks designed for engineering access need to be enhanced, or instead, utilities need to design substation networks that satisfy the reliability and determinism requirements of protection and control communication from the beginning. This chapter reflects knowledge guided by experience of multiple teams that have deployed Ethernet and IEC 61850 in electric power systems around the world.

It is important to ensure that the systems include well-engineered modern solutions based on secure and deterministic digital communications. Degraded performance of ICT networks based on shared bandwidth techniques of Ethernet and Multiprotocol Label Switching (MPLS) must be observed, alarmed, and replaced. ICT designers must understand the fundamental first principles of Ethernet and MPLS to use them dependably and securely. In fact, IT and OT ICT network designers must collaborate to address completely different expectations for similar acceptance criteria terms of dependability and security. IT practices and poor OT design and configuration of both PCM IEDs and network switches and routers will fail to prevent dropped packets. Moreover, network switches and routers used to build OT networks must have extended features, such as temperature ranges and must be substation rugged as these devices perform under harsh environmental conditions. Using rugged substation OT devices with high mean time between failures (MTBF) will provide a reliable communication network.

Within Ethernet networks, delayed and dropped messages are inevitable. Tests demonstrate the degradation of application performance and eventual failure if near misses are ignored and networks are not designed to meet mission-critical standards. However, tests also show that when designed appropriately, with PCM IEDs designed with knowledge of the fundamental first principles of communications, Ethernet can behave in a deterministic, dependable, and secure manner. Designers, consultants, integrators, manufacturers, and end users are duty bound to understand and deploy best engineering practices to maintain the safe and

reliable delivery of electric power. The role of human intervention has been reduced and is being replaced more and more by sophisticated network engineering based on IEEE, IEC, and other standards. Carefully and appropriately designed Ethernet networks make common sense, and it is imperative to make common sense common practice. Identifying near misses and correcting root causes are not only good practice, but are the obligations of designers, consultants, manufacturers, and integrators. Utility staff need to be aware of all these communications constraints and should seek appropriate technical assistance when defining and implementing a smart grid modernization strategy.

Note

1. Type of networking device that connects an internal local area network (LAN) with an external wide area network (WAN) or the Internet. It provides interconnectivity and traffic translation between different networks on their entering edges or the network boundaries.

Defining a Distribution-Level Grid Modernization Strategy and Investment Plan

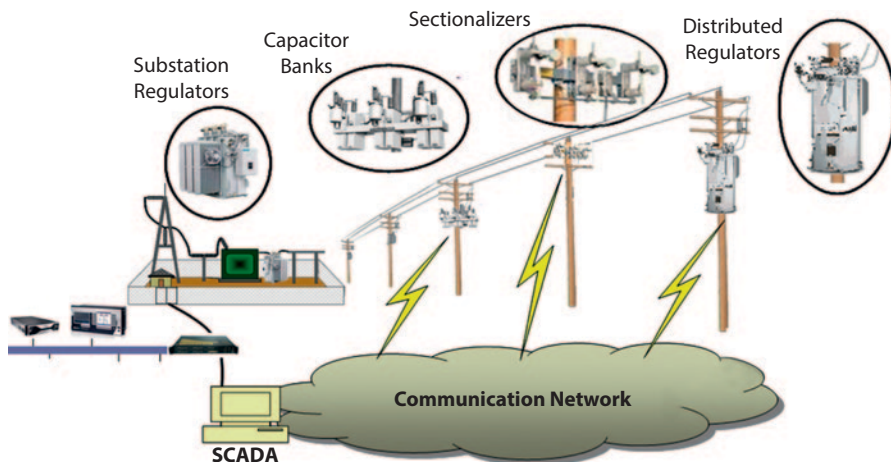
This chapter covers recommended strategies for distribution grid modernization. Each utility's grid modernization strategy will be somewhat different based on the technology starting point, level of available resources, and vision. Electric distribution utilities in developing countries may lack some of the basic building blocks and resources needed for grid modernization. This chapter describes grid modernization strategies for various initial starting points and covers prudent investments that can facilitate the transition to a smart distribution system.

The amount of grid modernization that can be accomplished depends on the availability of key equipment including controllable power apparatus (line switches, capacitor banks, voltage regulators, and distributed energy resources [DERs]), the number and locations of distribution sensors, and the availability of reliable and effective telecommunication facilities. And, of course, the grid modernization activities that can be accomplished are constrained by the availability of financial and technical resources.

Getting Started

As stated earlier, the process of developing a distribution grid modernization strategy begins with a careful assessment of key business drivers and a long-range vision for grid modernization. This should be followed with an assessment of existing technologies that are currently in place at the utility. Use of existing facilities is a key factor in accomplishing grid modernization with available financial and technical resources. In particular, the utility should assess the following technology issues to determine its current level of technology deployment, which in turn will help determine what level of grid modernization can be done with limited financial and technical resources.

Figure 5.1 outlines the basic building blocks of grid modernization. These are essential components that are needed to achieve the business objectives

Figure 5.1 The Basic Building Blocks of Grid Modernization

Source: McGranaghan and Uluski 2010.

established for the grid modernization project. This is followed by a description of the fundamental elements of each building block.

- *Controllable, electrically operable power apparatus.* The recommended grid modernization strategy requires the ability to control certain key distribution power apparatus based on an assessment of varying operating conditions to meet established reliability, efficiency, and performance objectives. Controllable components that are fundamental to grid modernization include medium voltage (MV: 12 kilovolt to 35 kilovolt) line switches, voltage regulators, and capacitor banks that are located distribution HV/MV substations and out on the feeders themselves. If power apparatus can only be operated manually by field crews and does not support automatic and remote control, the amount of grid modernization that can be accomplished is severely limited. To achieve maximum grid modernization benefits, automatic or remote control of power apparatus is essential.
- *Intelligent sensors.* Most grid modernization application functions require measurements and equipment status indications from power apparatus that can be located anywhere on the distribution system. Many older control systems relied solely on "local" measurements (that is, measurements taken at the device itself) and local controllers that were implemented as part of the associated power apparatus. To achieve grid modernization application functions, the advanced control functions require inputs from devices installed at different locations across the power grid. This is needed to permit well-coordinated, system-level control actions (versus control actions based solely

on local measurements). Grid modernization requires intelligent sensors and controllers that are able to acquire “local” measurements and transmit these pieces of information to centrally located distribution system operators and control systems.

- *Telecommunication infrastructure.* As stated above, the ability to acquire near real-time (within 5–10 minutes of the actual measurement time) measurements and status indications from intelligent sensors (located anywhere on the electric distribution system) and issue control commands to power apparatus (that can also be located anywhere on the system) is a cornerstone of grid modernization. Providing digital communications between the distribution control center and HV/MV substations is a starting point. But providing a telecommunication system that is able to reach the extremities of the distribution system is often needed to accomplish the ultimate vision for grid modernization.

The next section provides guidelines and recommendations for achieving specific grid modernization objectives for different starting points. For each grid modernization level, the section explains what objectives can be achieved and outlines a strategy for achieving them. The section also provides strategies for advancing to the next grid modernization level.

Grid Modernization Levels

This section describes four levels of grid modernization—that is, the levels of automation that currently exist at a given electric distribution utility and progressively more sophisticated levels of grid modernization that may be needed to accomplish the utility’s vision for grid modernization. The levels are listed below:

- *Level 0:* Manual control and local automation define a situation in which most processes are performed manually with little or no automation. This is a situation that exists at many utilities in developing countries.
- *Level 1:* Substation automation and remote control build on level 0 by adding IEDs and data communication facilities to achieve greater monitoring and control capabilities at HV/MV substations.
- *Level 2:* Feeder automation and remote control build on level 1 by extending remote monitoring and advanced control to the feeders themselves (outside the substation fence). This level also includes information from communicating meters at some large customers for improved control and decision making.
- *Level 3:* DER integration and control and demand response—the highest level of grid modernization described in this report—add energy storage, static VAR sources, and advanced communication and control facilities to effectively integrate and manage high penetrations of DERs on the distribution feeders. This level of grid modernization also includes deployment of AMI to enable on-demand reading of customer meters along with DR capabilities.

While increasing levels of grid modernization represents a natural progression from manual paper-driven processes to electronic computer-assisted decision making with automation, it is possible (and in many cases recommended) that a utility that is presently at a low level of grid modernization bypass one or more higher levels of automation. That is, a utility at a relatively low level of grid modernization may “leapfrog” one or more levels of grid modernization to achieve some of the benefits offered by the highest levels of grid modernization. Most utilities in developed countries have followed a gradual progression by implementing the best available technologies at any given time. But it is not necessary for a utility that is currently using electromechanical technology from the 1970s or earlier to gradually modernize by first installing 1980–90 technology (solid state devices), and then replace these units at some later date with 21st-century IEDs. Utilities in developing countries that have not completely built out their electric system may elect to bypass some of the traditional modernization steps (see section “Summary of Grid Modernization Projects” for details).

The following subsections describe each grid modernization level in more depth, outline a strategy for achieving each level, and identify grid modernization benefits that can be achieved at each level.

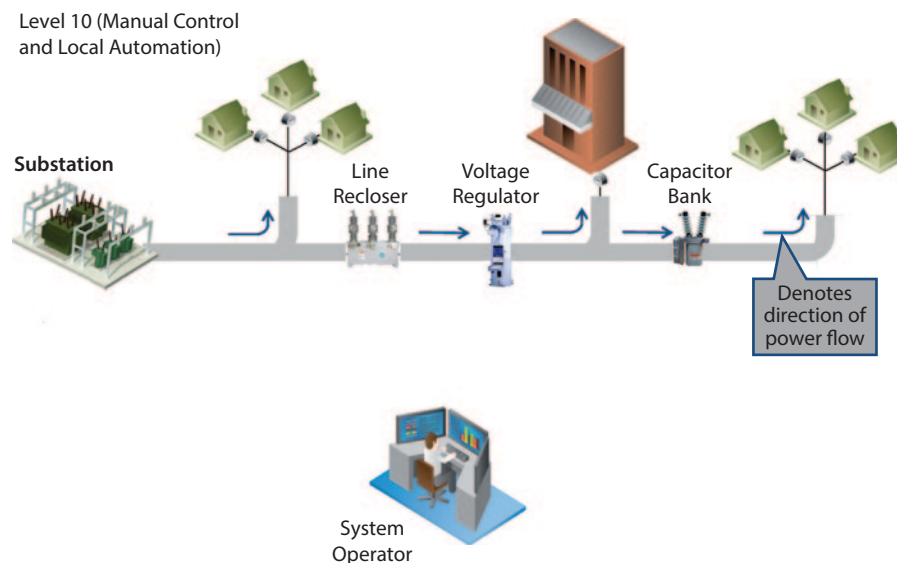
Level 0: Manual Control and Local Automation

At this grid modernization level, operation of the distribution system is mostly manual. Level 0 grid modernization is depicted in figure 5.2. Automatic functions are limited to distribution feeder protection, voltage regulation, and in some cases capacitor bank switching for power factor correction. Protective relays, voltage regulators, and capacitor bank controllers may be electromechanical devices, electronic devices, or IEDs. Most likely, these devices are all electromechanical devices (especially in developing countries), which means they lack the intelligence to adapt to varying operating conditions and they lack the ability to supply local measurements to a remote processor for additional analysis and control.

Another characteristic of this grid modernization level is the lack of data communication facilities that are needed for more advanced data acquisition and control functions. As a result, all automatic control actions performed by protective relays, voltage regulators, and switched capacitor banks are based on “local” (at the device itself) measurements and equipment status indications.

Out on the feeders (outside the substation fence), most (if not all) line switches are manually operated. But some switches may be line reclosers, which are fully automatic fault interrupting devices. It is assumed that most distribution feeders have normally open ties to adjacent feeders, and that these tie switches must be operated manually by field crews. No communication facilities exist for feeder devices; hence, remote monitoring and control of feeder devices is not possible at this level.

The grid modernization objectives that can be achieved with this level of automation are somewhat limited due to the lack of communication between

Figure 5.2 Level 0 Grid Modernization

Source: Uluski 2013.

devices and availability of information from intelligent sensors. Following are descriptions of the grid modernization objectives and benefits that may be achieved when the starting point is grid optimization level 0.

Reliability Improvement

- *Limited FLISR.* If properly coordinated line reclosers exist on the feeder, and normally open tie switches are available between adjacent feeders, it is possible to obtain some of the benefits of the FLISR grid modernization application function. The following additional equipment and control logic is needed to provide this functionality:
- *If normally open tie switches are load-break switches,* replace these switches with line reclosers that are fully automatic and have fault interrupting capability.
- *Equip all line reclosers* (including normally open tie switches) with loss-of-volt detection (undervoltage relays). If voltage is lost at a normally closed line switch for a specified time period, then this switch would automatically open to isolate an “upstream” fault (that is, a fault that is closer to the substation than the switch). If voltage is lost on either side of the normally open tie switch, this switch should close to restore service to the deenergized component.

This strategy would enable the utility to significantly improve feeder reliability. But since the service restoration logic does not verify that sufficient capacity exists

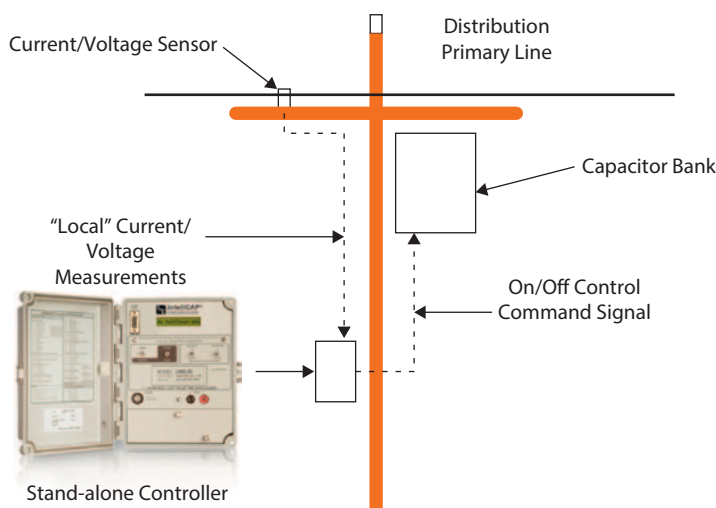
on backup sources at the time of the fault, there is a risk that the load transfer will result in an overload on the backup feeder. Another downside to this approach is that the normally open tie switch may close into a faulted section of the feeder, thus subjecting the feeder equipment to additional through fault current.

Reduction of Electrical Losses

Reducing electrical losses is an especially important business objective for utilities in developing countries, where the level of losses may exceed 25 percent of total energy consumption. This is considerably higher than the rest of the world. Electrical losses of concern include both technical losses (I^2R heating of energized components) and nontechnical losses (energy theft and unmetered loads). For these utilities, electrical loss reduction should be an integral part of the grid modernization strategy.

- Volt/VAR control using local stand-alone controllers. At grid modernization level 0, electric distribution utilities may use stand-alone controllers for operating switched capacitor banks, voltage regulators (including substation transformers with under LTCs), and other volt/VAR control devices. In the past, these controllers were in effect switches that turned the associated power apparatus on or off at specified times corresponding to peak load and minimum load conditions. Newer IED-based stand-alone controllers can base their operation on a number of “local” measurements (current, voltage, reactive power flow, ambient conditions, and so on) to improve the overall performance of the volt/VAR control system. This, in turn, allows the utility to further reduce electricity losses and improve overall efficiency. Figure 5.3 depicts the local controller approach to local volt/VAR control.

Figure 5.3 Standalone Local Controller Used for Volt/VAR Control

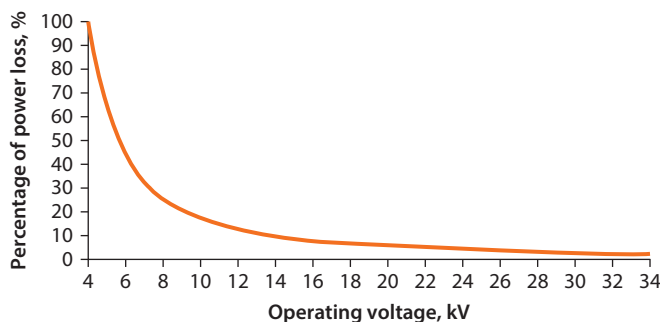


Source: World Bank.

The electric distribution utility should also consider adding new switched capacitor banks to the distribution feeder. Optimal locations for placing new capacitor banks should be determined using distribution engineering analysis software tools (optimal capacitor placement).

- **Reconductoring of primary and secondary distribution networks.** Given that the load losses of the distribution system are directly proportional to the series resistance of distribution components, electrical losses can be reduced by replacing existing primary and secondary lines with conductors of greater capacity. While it is clear that the larger the conductor's cross-sectional area, the lower the line losses, the benefits/costs associated with reconductoring depend on the system. Benefits include improving the voltage profile (due to a reduction in the voltage drop along the feeder) and adding available capacity for load transfers to or from neighbor feeders, which also has a positive impact on system reliability.
- **Voltage upgrading.** For some distribution systems (for example, high-load-density areas, long rural feeders), a design practice recommended to economically decrease conductor losses through current reduction is to increase primary voltage; this is known as voltage upgrading or voltage conversion. The apparent power in a conductor is proportional to voltage and current; doubling primary operating voltage will reduce the conductor current by half for the same feeder power flow. Hence, the resulting load loss is 25 percent that of the original voltage using the same feeder conductor and length, as shown in figure 5.4. Going from 11 kilovolt to 33 kilovolt will reduce the load current by two-thirds, so the load losses will be one-ninth of the original losses. Figure 5.4 illustrates the impact of voltage upgrading on feeder conductor losses.
- **Transformer losses.** These are an important purchase criterion and make up an appreciable portion of a utility's overall losses. This applies to both substation transformers and distribution service transformers. The Oak Ridge National Laboratory (Knoxville, TN, United States), a leading research institution, estimates that distribution transformers account for 26 percent of transmission

Figure 5.4 Impact of Voltage Upgrades on Losses

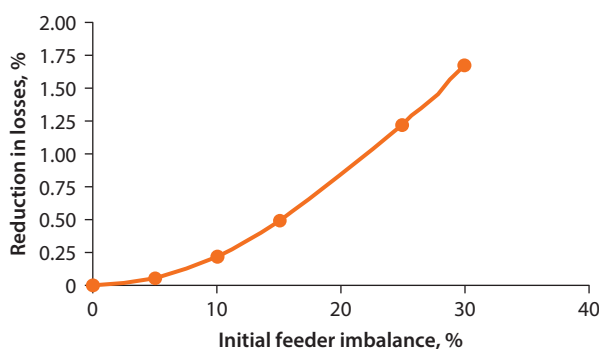


and distribution losses. A current best practice is to install high-efficiency distribution transformers to reduce overall distribution losses. Many utilities in developing countries are replacing old, highly inefficient transformers with modern silicon-steel-core transformers. Moreover, modern transformer load management (TLM) systems are being implemented for tracking transformer loadings (for example, distribution transformers are typically at maximum efficiency when loaded at 50 percent of the nominal rating). This tool allows the more accurate economic evaluation of transformer loadings, taking into account several cost components (losses, capital, loss of life, and so on).

- *Network reconfiguration and load balancing.* Network reconfiguration consists in changing the status of distribution switches (from normally open to normally closed and vice versa) to improve the paths of load flow to better serve varying location and time-dependent factors of distribution load. By switching to better distribute load, the system I2R delivery losses will decrease. This is because the total losses on one heavily loaded feeder and one lightly loaded feeder are greater than the total losses on two medium-loaded feeders. Load unbalance is a common occurrence in three-phase distribution systems. It can be harmful to the operation of the network and reduce reliability and safety. Furthermore, measurements and computations reported by the international literature show that losses increase due to unbalanced loads, mostly due to the circulation of unbalanced currents through neutral conductors. For instance, for a 15 percent current unbalance, the losses of a real low-voltage network in Brazil were 4.1 percent more than those of a fully balanced network. This problem in distribution networks exists in both three- and four-wire systems due to the fact that loads are switched on and off by end-users. Figure 5.5 shows the impact of feeder load balancing on technical losses.

Extreme load unbalance also causes voltage unbalance, which affects sensitive electronic equipment and causes the overheating (and the increase of losses) in motor loadings. Though the problem is challenging, the solution is low cost:

Figure 5.5 Impact of Load Balancing on Electrical Losses



Source: World Bank.

performing load balancing typically involves only metering equipment and labor costs, not capital investments. Load balancing is therefore a primary way that utilities try to reduce losses, and is a highly recommended option for utilities in developing countries.

Efficiency Improvement

Efficiency improvement refers to the process of accomplishing the same amount of work while consuming less energy to perform this work. Efficiency improvement projects can help utilities avoid having to build new generating facilities and add new transmission and distribution power delivery facilities.

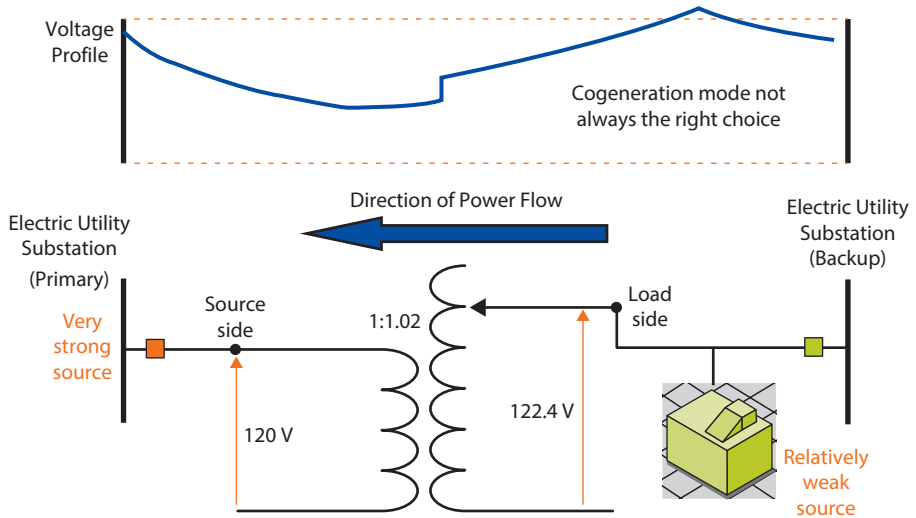
- *Limited conservation voltage reduction.* The utility should replace voltage regulator controls (as needed) in HV/MV substations and out on the feeders with new controllers that include line drop compensation (LDC) capabilities. The settings of the new voltage regulators should be lower than normal voltage settings to achieve the benefits of voltage conservation. Due to the lack of voltage feedback from feeder extremities, utilities that deploy this strategy may be forced to build additional operating margins into the voltage regulator settings to avoid unacceptably low voltage when running conservation voltage reduction (CVR) during peak load conditions.

DER Integration

Voltage regulation with reverse power flow. The recommended level 0 strategy is to install bidirectional voltage controls (with a cogeneration feature) on voltage regulators installed out on feeders that have a high penetration of DERs. A high penetration of DERs on a given feeder can produce reverse power flows (back toward the substation) and a potential for voltage rise on feeder locations further from the substation. To avoid potential high-voltage conditions at certain feeder locations due to such reverse power flows, the recommended bidirectional voltage controls take suitable control actions (opposite from the normal control direction) when reverse power flow is detected. The impact of reverse power flow on voltage regulation is shown in figure 5.6.

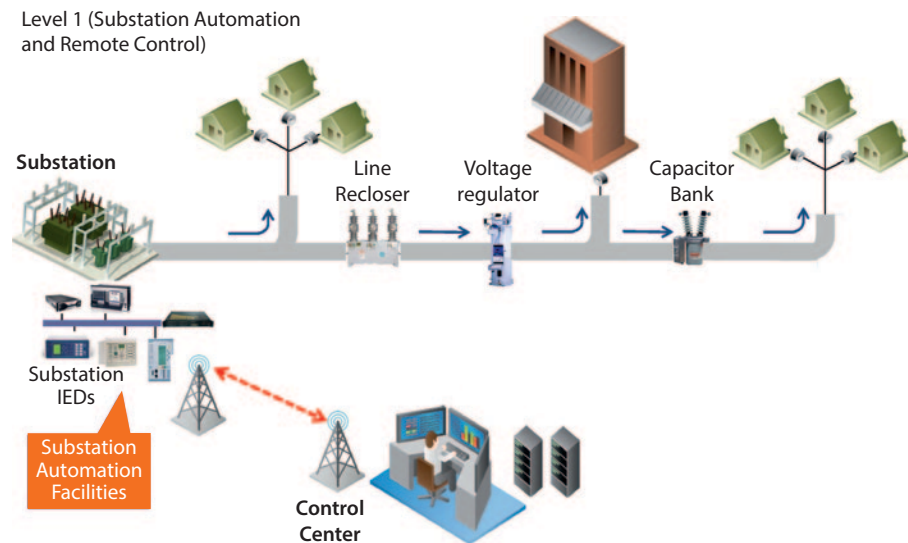
Level 1: Substation Communication and Automation

Modernization of HV/MV substations should receive high priority in the distribution grid modernization strategy. This is because most of the equipment that is responsible for controlling the performance and protection of the distribution grid resides in the HV/MV substations, and significant grid modernization benefits can be achieved through improved monitoring and control of this equipment. Hence, for utilities that are currently at grid modernization level 0 (as is the case in many developing countries), implementation of level 1 grid modernization should be the first step in the utility's grid modernization strategy. Level 1 modernization enables continuous near-real-time monitoring and advance control of HV/MV substation power apparatus, thus enabling a number of the grid

Figure 5.6 Impact of Reverse Power Flow on Voltage Regulation

modernization applications that have been identified. Level 1 grid modernization is depicted in figure 5.7.

Level 1 grid modernization includes the replacement of electromechanical controllers, protection, and metering devices in the substation with substation IEDs, along with substation remote terminal units (RTUs) or data concentrators that acquire, store, process, and transmit information acquired from IEDs to a

Figure 5.7 Level 1 Grid Modernization

Source: World Bank.

control center. Installing substation IEDs is a resource-intensive process that is often completed over many years at a rate of several substations per year. Strategies for implementing substation IEDs include replacing electromechanical devices as they fail with IED versions of the same device and using IEDs for all new construction work and substation modernization projects. This strategy may take many years to complete due to the limits of available resources to perform the device upgrades. Because the expected lifetime of substation IEDs is 20–25 years, the entire upgrade project should be completed before IEDs installed at the beginning of the project begin to fail. Figure 5.8 depicts the general architecture of the modern, IED-based substation.

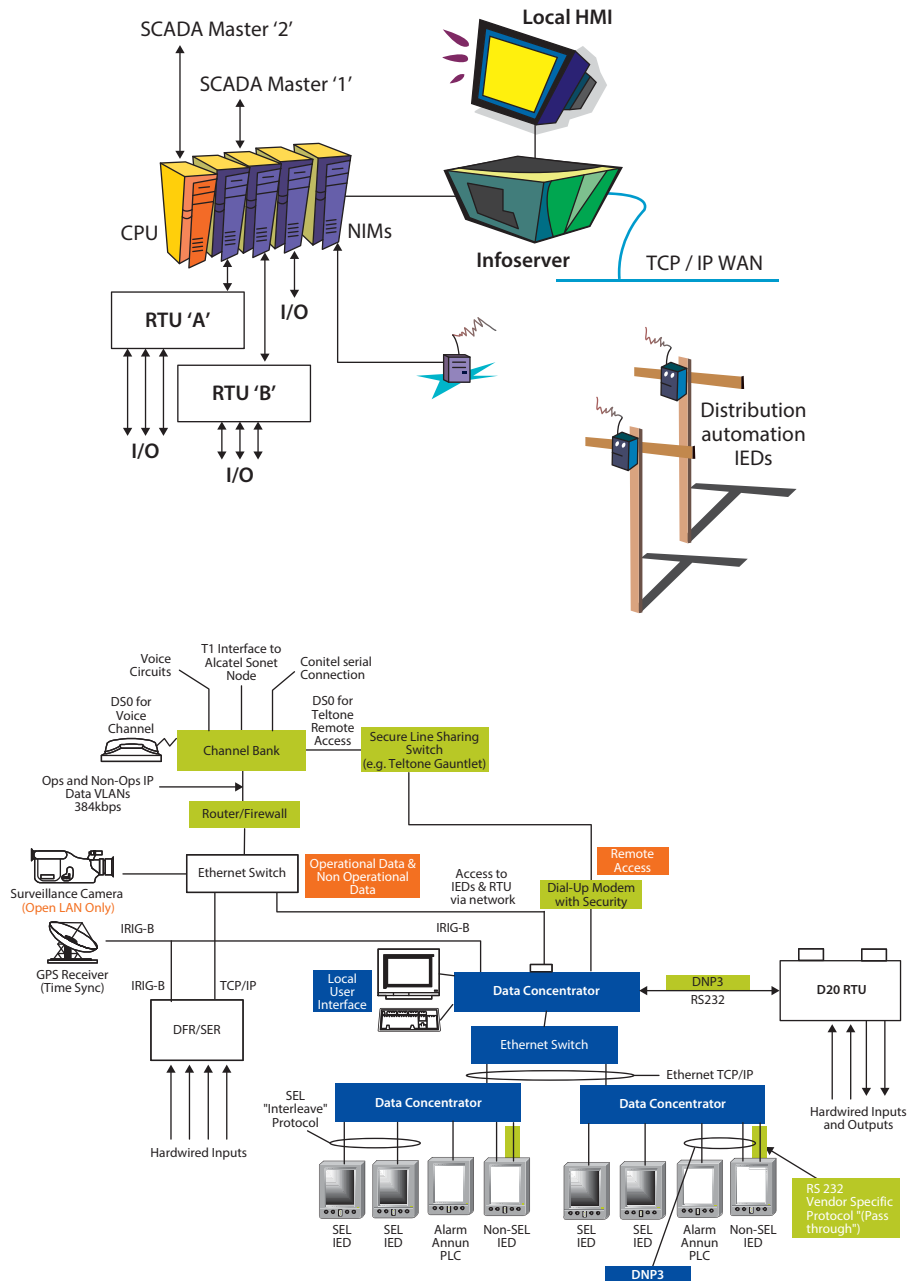
Level 1 also includes the addition of reliable and effective communication facilities between the HV/MV substations and the distribution control center (or equivalent centralized facility). These communication facilities enable telemetering of information from the IEDs to a control center and the delivery of control commands from the control center to the IEDs. There are many possible choices for the substation communication infrastructure. Choices include public communication infrastructure (leased telephone lines, cellular networks, and so on) and private networks (licensed radio; optical fiber, especially optical ground wires [OPGW]).

Level 1: Grid Modernization Applications

Grid modernization application functions that can be accomplished with level 1 modernization include:

Reliability Improvement

- *Early detection of service interruption.* Protective relay IEDs in the substation are continuously monitored, so when a feeder circuit breaker trips, distribution system operators are informed immediately so that service restoration activities can begin without waiting for customers to call. This reduces the duration of outages.
- *Fault location.* When a feeder fault occurs, protective relay IEDs are able to compute and report (via the substation communication network) the electrical distance to the fault. As a result, field crews can be dispatched to a more precise fault location, resulting in shorter fault investigation time and reduced outage time.
- *Fuse-saving schemes.* Protective relay IEDs are able to store multiple relay setting groups that can be selected as needed by the distribution system operator. During inclement weather, when temporary faults are most likely to occur, the operators can select a “fuse-saving” setting group that will allow the substation circuit breaker to clear a temporary fault and then reclose (reenergize the circuit) before downstream fuses blow to cause a permanent fault. This reduces the duration of outages and also the time needed to replace blown fuses.

Figure 5.8 A Modern IED-Based Substation

Source: World Bank.

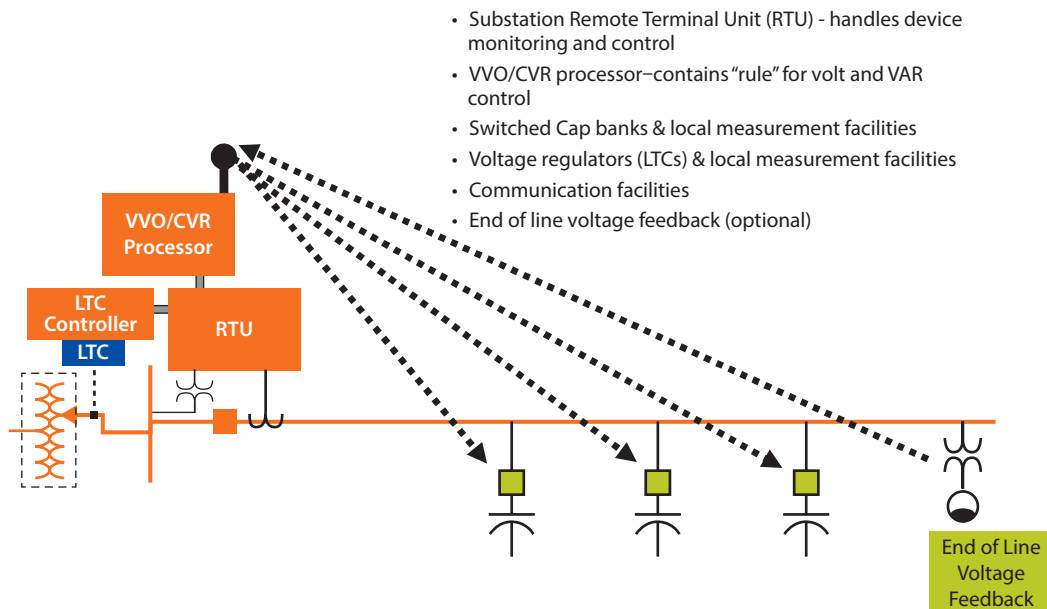
- *Intelligent bus failover.* The substation automation scheme can be used to implement a medium bus failover scheme at substations that do not have firm capacity. When a substation transformer fails or a bus fault occurs, only those distribution feeders that can be safely transferred to the remaining healthy bus or transformer would be restored to service.
- *Reliability-centered maintenance.* The substation IEDs are able to monitor and report information about the operating and maintenance status of key substation equipment. By tracking parameters such as substation battery condition and circuit breaker contact wear and trip-cycle timing, the utility is able to identify incipient problems that may be corrected before a full-blown failure occurs.

Reduction of Electrical Losses

- SCADA “rule-based” volt/VAR optimization. Arguably the most common approach to VVO in use today is the SCADA “rule-based” approach. This approach determines what volt-VAR control actions to take by applying a predetermined set of logical “rules” to a set of real-time measurements from the associated substation and feeder. An example rule is: If the voltage measured at point “X” is less than 120 volts AND the reactive power flow measured at the substation end of the feeder is greater than 900 kVAR (lagging), then switch capacitor bank “1” to the ON position. These rules are determined in advance by the distribution engineers and operators using power flow analysis. Figure 5.9 depicts a distribution SCADA, rule-based volt-VAR control system that might be included in grid modernization level 1.

The SCADA rule-based approach is similar to the stand-alone controller approach in that both approaches rely on intelligent controllers to interface with the switched capacitor banks, voltage regulators, LTCs, and other volt/VAR control devices. The most significant difference between the SCADA rule-based approach and the stand-alone controller approach is the addition of communication facilities that are typically part of a distribution supervisory control and data acquisition (DSCADA) system. The communication facilities enable the system to base its control actions on overall system conditions rather than just on local conditions at the site of the capacitor bank or voltage regulator. The communication facilities also enable the electric distribution utility to monitor the operating status of the field voltage control and VAR control equipment so that appropriate actions can be taken immediately when a component failure occurs.

- *On-line power flow.* Substation IEDs are able to monitor and telemeter near real-time electrical parameters from the substation end of the feeder. These electrical parameters allow the deployment of an on-line power flow (OLPF) program that will improve the operator’s situational awareness. OLPF results can also be compared with customer billing records to assist in identifying technical and nontechnical electrical losses. An application commonly referred

Figure 5.9 SCADA “Rule-Based” Approach

Source: World Bank.

to as *energy balancing* compares energy delivered to the feeder with billing records to determine nontechnical losses.

Integration of DERs

- *Detection of reverse power flow.* Continuous monitoring of power flow magnitude and direction at the substation end of the distribution feeder would enable the utility to detect reverse power flow conditions at the substation end of the feeder. This may occur on distribution feeders that have a high penetration of DERs, especially when these DERs are operating at maximum capacity during light load conditions. Such reverse power flows can produce unacceptable high-voltage conditions out on the feeder that must be promptly corrected by regulating voltage or reducing DER output.

Level 1: Summary

Level 1 activities compose the basic building blocks of distribution grid modernization at electric distribution substations. Associated investment in substations will enable an electric distribution utility to improve asset utilization, reliability, efficiency, and overall performance while providing a foundation upon which to build the more advanced levels of grid modernization. Table 5.1 summarizes the grid modernization level 1 activities, qualitative costs and benefits, and risks associated with level 1 activities.

Table 5.1 Level 1 Costs, Benefits, and Risks

<i>Grid Modernization Level</i>	<i>Costs (Qualitative)</i>	<i>Benefits (Qualitative)</i>	<i>Risks</i>
<i>Level 1 Activities</i>			
Substation IEDs	Purchase and install in substations: <ul style="list-style-type: none"> • Intelligent electronic devices (IEDs) • Data communications network • Remote Terminal Unit (RTU) or Data Concentrator 	<ul style="list-style-type: none"> • Improve protective relay reliability through self-diagnostics • Wealth of new information for grid modernization applications • “Distance-to-fault” information for faster service restoration 	<ul style="list-style-type: none"> • Learning curve for field personnel • Potential information overload for operations personnel • Increased risk of cyber attack
Equipment Condition Monitoring	<ul style="list-style-type: none"> • Purchase and implement analytical software for equipment condition monitoring • Develop O&M procedures for condition-based maintenance 	<ul style="list-style-type: none"> • Fewer “routine” inspections reduce maintenance costs • Detection of incipient problems • Lower repair costs (fix problems proactively while problem is small) 	<ul style="list-style-type: none"> • Immature technology • “False alarms” for equipment condition problems • Loss of confidence in Equipment Condition Monitoring data outputs
Dynamic Equipment Rating	<ul style="list-style-type: none"> • Purchase and install new sensors (e.g. transformer winding temperature) • Develop and implement application software for dynamic ratings 	<ul style="list-style-type: none"> • Improved asset utilization • Defer capital expenditures for capacity additions • Reduce need for load shedding • Improved reliability 	<ul style="list-style-type: none"> • Immature technology • Learning curve • Potential equipment overloading if sensor fails
Adaptive Protection	Purchase and install: <ul style="list-style-type: none"> • Protective relay IEDs • Substation communication facilities • Software to support automatic setting changes 	<ul style="list-style-type: none"> • Reliability improvement due to having relay settings that match the “as operated” conditions • Labor savings (eliminate need for manual setting changes) 	<ul style="list-style-type: none"> • Field personnel uncertainty about current relay settings • Alternate settings may not apply to all possible reconfiguration options
Voltage reduction	<ul style="list-style-type: none"> • Labor cost to change voltage regulator (or LTC) settings to reduced voltage 	<ul style="list-style-type: none"> • Lower peak demand • Improved efficiency • lower greenhouse gas emissions 	<ul style="list-style-type: none"> • Lost revenue due to lower KWh sales • Increased risk of low voltage • Reduced benefits over time due to changing load characteristics • Voltage reduction benefits may not be realized due to: <ul style="list-style-type: none"> • existing low voltage • constant power loads

Source: World Bank.

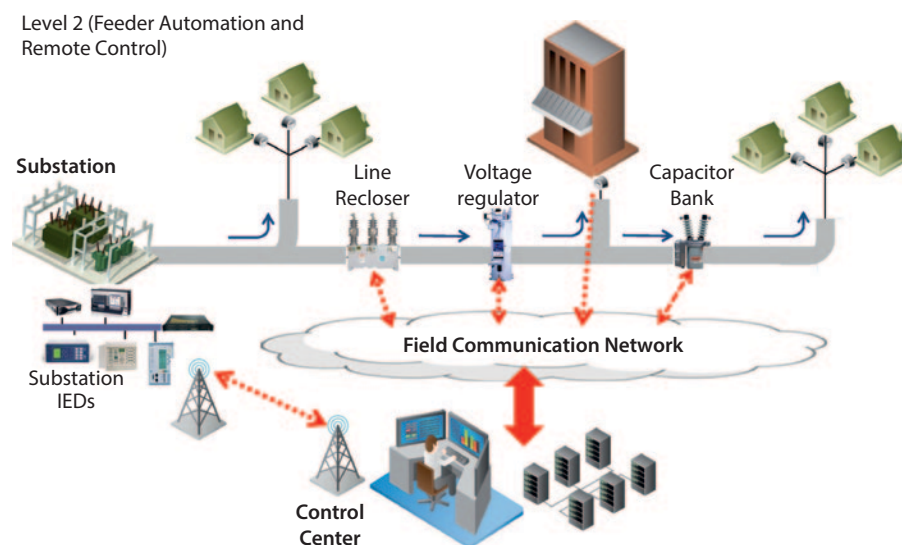
Level 2: Monitoring and Control of Feeder Devices

For utilities that have automated some or all of their HV/MV substations (level 1 grid modernization), the next evolutionary step in distribution grid modernization should be to implement remote monitoring and control of distribution power apparatus located out on the distribution feeders themselves (outside the substation fence). In this report, this is referred to as *level 2 grid modernization*.

The level 2 grid modernization strategy includes the addition of remote monitoring and automatic control facilities to existing line switches, capacitor banks, voltage regulators, and other utility-owned equipment (see figure 5.10). The remote monitoring and control facilities allow well-coordinated optimal control of the field devices to achieve overall distribution system needs (versus “local” needs). All power apparatus that are included in the level 2 grid modernization strategy must be “electrically operable,” that is, each device must be equipped with an operating mechanism that can be controlled via an electrical trip signal. Devices that can only be operated manually by field crews are not suitable for level 2 grid modernization. To be included in the level 2 strategy, manually operated devices must be retrofit with an electrical operating mechanism or replaced with a device that is designed for remote control and fully automatic operation.

The level 2 strategy also involves implementing intelligent sensors at many strategic locations on the feeder, such as main feeder branches, major equipment locations, points of connection for large customer-owned DERs, and feeder extremities. Intelligent sensors that are incorporated (embedded) in the electrically operable power apparatus and associated controllers should be used to the fullest extent possible. The level 2 grid modernization strategy may also include

Figure 5.10 Level 2 Grid Modernization



Source: World Bank.

the addition of separate stand-alone intelligent sensors, such as faulted circuit indicators and end-of-line voltage meters.

Level 2 also requires an extensive network to provide one- or two-way communications to each intelligent device out on the feeder. Two-way communications are needed for power apparatus that require remote control and data acquisition facilities. One-way communications are sufficient for sensors (such as faulted circuit indicators) that only report data (no control needed). Since the end devices mentioned above can be located anywhere in the distribution utility's service territory (including its furthest extremities), implementing the required communication network is especially challenging. A wide variety of communication technologies are available for accomplishing these communication requirements. Technologies that may be used include licensed and unlicensed radio (only used where permitted by telecommunication regulations), public telephone networks (including cellular networks), satellite radio (for extremely remote areas only), optical fiber, and power line carrier. Note that power line carrier communication technologies may not be suitable for implementing FLISR, fault location, and other applications that must perform reliably when line damage is present. In most cases, the communication network for level 2 grid modernization will involve a hybrid design of more than one communication technology. The communication strategy should leverage the substation communication network to the fullest extent possible; for example, a feeder device may communicate to the distribution control center via the associated substation that is equipped with a substation communication network (level 1 grid modernization).

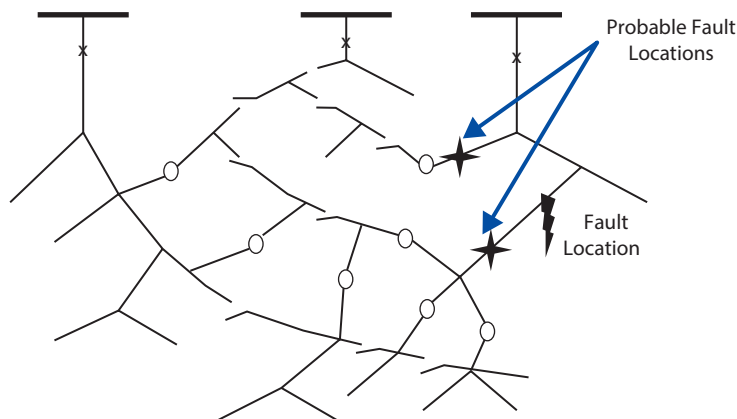
Because of the enormous technical and financial resources needed to automate all distribution feeders, the recommended practice is a phased approach that automates a portion of the feeders each year. To obtain the maximum incremental benefits for the initial investments, priority should be given to the worst-performing feeders (feeders with poor reliability, high losses, and so on).

Level 2 Application Functions

Grid modernization application functions that can be accomplished with level 2 modernization (in addition to level 0 and level 1 benefits) include the following:

Reliability Improvement

- *Fault location isolation and service restoration (FLISR).* Level 2 grid modernization enables the utility to implement rapid service restoration for customers on healthy sections of the feeder without risking overloads of adjacent backup feeders and without exposing the substation and feeder equipment to additional fault current during unsuccessful reclosures.
- *Fault location.* Telemetered fault detector and faulted circuit indicator outputs from strategic feeder locations allow the utility company to narrow down the possible fault location considerably. This reduces fault investigation and patrol time, and thereby overall outage duration. Figure 5.11 depicts the results of the predictive fault location program.

Figure 5.11 Predictive Fault Location

Source: World Bank.

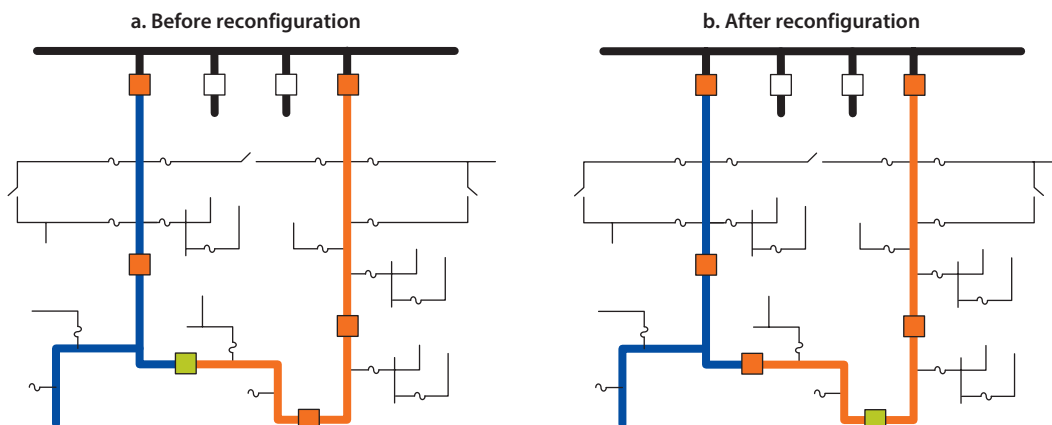
- *Improved intelligent bus failover.* Further improvements can be made to the intelligent bus transfer scheme proposed for level 1 modernization. When a substation transformer fails or a bus fault occurs during heavy loading conditions, some feeders may be transferred (if necessary) to adjacent substations by closing normally open tie switches via remote control.

Reduction of Electrical Losses

- *Coordinated volt/VAR control.* Adding communication facilities and controller IEDs to the feeder voltage regulators and switched capacitor banks enables a true VVO system that provides fully coordinated operation of all volt and VAR control devices. This enables the utilities to achieve various operating objectives, including reduced electrical losses and lower demand. The level 2 VVO system also allows the utility to minimize the quantity of voltage regulator tap positions, which in turn can lower maintenance costs and extend the lifetime of this equipment. The level 2 communication system also enables the utility to determine the operating status of voltage and VAR control devices, so the failures of such equipment can be detected and corrected as quickly as possible with requiring routine physical inspections by field crews.

Efficiency Improvement

- *Conservation voltage reduction.* End-of-line voltage monitoring sensors provide feedback to the CVR application, thus enabling the utility to maximize voltage reduction and associated benefits without the risk of unacceptably low voltage.
- *Improved online power flow.* Intelligent sensors added during level 2 modernization improve the accuracy of OLPF results. Improved accuracy enables the utility to operate the feeder with lower operating margins to improve loading, efficiency, and overall performance.

Figure 5.12 Optimal Network Reconfiguration

Source: World Bank.

- *Optimal network reconfiguration.* The addition of remote-controlled line switches coupled with numerous new sensors for load and voltage measurement enable the utility to deploy optimal network reconfiguration (ONR) as part of its suite of grid modernization application functions. ONR identifies and executes feeder switching scenarios to achieve better load balance among adjacent feeders, which will lower total electrical losses. Figure 5.12 depicts the operation of ONR.

Integration of DERs

- *Bidirectional voltage regulation.* Level 2 grid modernization enables the utility to detect reverse power flow that occurs out on the feeder due to the presence of a high penetration of distributed generating sources. This flow results in a voltage rise further from the main substation source of supply, which, in turn, can cause unacceptably high voltage. The use of remote-controlled, bidirectional voltage regulators (equipped with a “cogeneration” feature) helps the utility to address this situation and possibly enables a higher penetration of distributed generating resources on the feeder.
- *Monitoring and transfer tripping of DG units.* Level 2 grid modernization includes continuous near-real-time monitoring of DERs, which improves the accuracy of OLPF results and thus operator situational awareness. The availability of feeder communications also allows the transfer tripping of larger DG units when feeder outages occur as part of an anti-islanding scheme.

Level 2 Summary

The level 2 activities expand the grid modernization investments made in level 1 from the substations to the feeders themselves (that is, to a portion of the feeders outside the substation fence). Level 2 grid modernization enables the utility to implement more advanced application functions such as volt/VAR control and

Table 5.2 Level 2 Benefits, Costs, and Risks

<i>Level 2 Activities</i>	<i>Costs</i>	<i>Benefits</i>	<i>Risks</i>
Distribution Feeder Sensors and Communication facilities	Purchase and install: <ul style="list-style-type: none"> • New sensors out on feeders • Two-way communication facilities • Maintenance costs for new field equipment 	<ul style="list-style-type: none"> • Enabler for level 2 applications • Improved visibility of distribution feeder conditions 	<ul style="list-style-type: none"> • Learning curve for field personnel • Information overload • Increased risk of cyber attack
SCADA Rule-Based VVO	Purchase, install and maintain: <ul style="list-style-type: none"> • VVO rules-processor • Sensors for voltage feedback • 2-way communications to all Volt-VAR control devices • VVO software 	<ul style="list-style-type: none"> • Reduce electrical losses and peak demand • Early detection of capacitor bank and voltage regulator problems • Eliminate routine inspections for capacitor banks & voltage regulators 	<ul style="list-style-type: none"> • Rules may not work effectively following feeder reconfiguration • Lost benefits if communication is lost learning curve for operators and technicians • Potential increase in voltage regulator tap position changes
Fault Location Isolation and Service Restoration (FLISR)	Purchase, install and maintain: <ul style="list-style-type: none"> • FLISR processor • Automated line switches • Fault detectors • 2-way communications • Software containing FLISR logic 	<ul style="list-style-type: none"> • Improve reliability through rapid service restoration • Reduce fault investigation time due to better fault location 	<ul style="list-style-type: none"> • Learning curve for operators • Increased risk of cyber attack

Source: World Bank.

Note: SCADA = supervisory control and data acquisition; VVO = volt/VAR optimization.

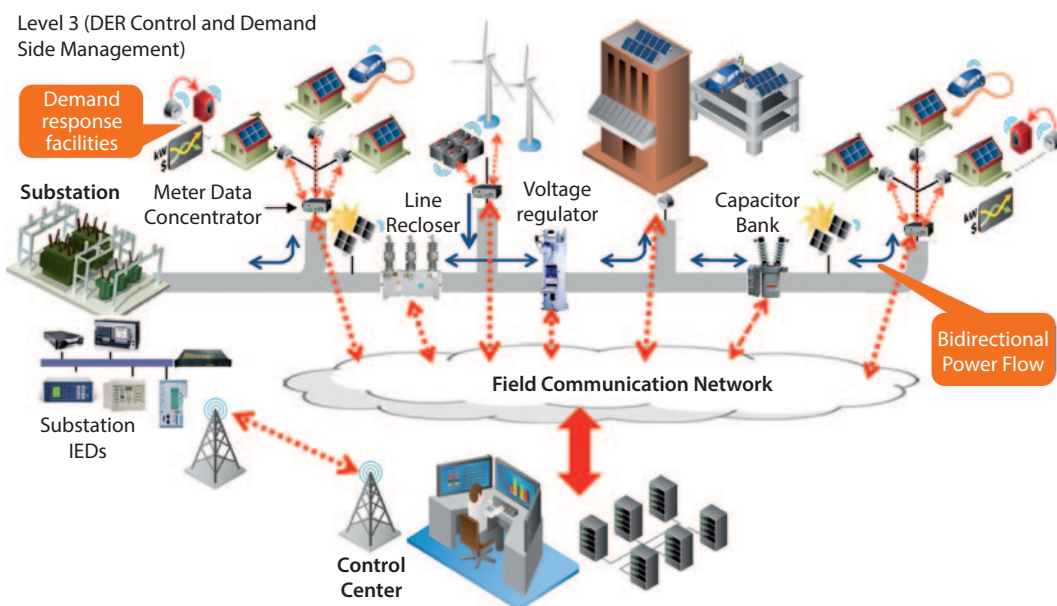
FLISR to improve efficiency and reliability. It also establishes an appropriate level of continuous monitoring out on the feeders to support the advanced functions that will be deployed in level 3 grid modernization to *optimize* the distribution system performance. Table 5.2 summarizes grid modernization level 2 activities and their qualitative costs, benefits, and associated risks.

Level 3: Active Control and Management of DERs and Demand Response

Level 3 is the highest level of distribution grid modernization that is envisioned at this time. This includes all of the substation automation and feeder automation strategies listed above, plus the addition of devices for active control and management of DERs, such as energy storage units and static VAR resources. This combination of new power apparatus technologies and advanced controllers enable the distribution utility to address many of the adverse impacts associated with DERs, such as the time-varying output of wind-powered and solar photovoltaic (PV) units. This, in turn, enables the utility to accommodate additional DERs on its distribution feeders. Figure 5.13 depicts level 3 grid modernization.

The recommended strategy for level 3 grid modernization includes the addition of energy storage units either in the HV/MV substations or near the customers in the form of community energy storage (CES). The energy storage units should include advanced controller IEDs that manage the charging and discharging strategy for the energy storage units based on local settings that can be overridden via remote control by the distribution system operator. The energy storage

Figure 5.13 Level 3 Grid Modernization



Source: World Bank.

units can be used for many purposes that support the utility's business drivers, including peak shaving on all or part of the distribution feeder, management of power fluctuations from renewable generating resources, and management of microgrid operations.

Another controllable resource that is recommended for grid modernization level 3 is static VAR sources. These are able to inject or absorb reactive power from the feeder when needed to mitigate the impact of power and voltage fluctuations caused by DG units with varying output. For example, when the output of the solar PV units suddenly drops off due to cloud cover, the static VAR source can quickly inject VARs to prevent significant drop-off (or collapse) of distribution feeder sources. It is technically possible to use conventional switched capacitor banks and voltage regulators to perform the necessary voltage adjustments or reactive power compensation. But conventional devices have several problems that limit their effectiveness in responding to such variations:

- Switched capacitor banks and voltage regulators have time delays before performing the requested actions. By the time the capacitor bank or voltage regulator operates, customers may already be experiencing noticeable low voltage. Time-varying conditions may change soon thereafter, resulting in another time-delayed control action for the conventional devices.
- The frequent operation of switched capacitor banks and voltage regulators increase maintenance requirements and reduce the expected lifetime of these devices.
- Frequent capacitor bank switching introduces harmonics into the voltage waveform that could adversely impact customer-owned equipment.

The recommended static VAR sources are able to respond rapidly to inject (or absorb) precise amounts of reactive power to address power and voltage fluctuations caused by renewables. These devices do not cause waveform distortion (harmonics) and are capable of performing many more operations than conventional devices, making them ideally suited to level 3 grid modernization.

Level 3 grid modernization should also include the deployment of "smart" AC inverters on customer-owned DERs, such as solar PV units. These smart inverters are able to operate using a wide variety of operating characteristics that enable the customer-owned equipment to respond rapidly to changing feeder requirements. For example, the volt/VAR smart inverter will supply or absorb VARs automatically based on the changing voltage level.

Level 3 Application Functions

Grid modernization application functions that can be accomplished with level 3 modernization (providing benefits in addition to those from levels 0, 1, and 2) include the following.

Reliability Improvement

- *Microgrid operation.* Energy storage and other fast-acting voltage and frequency control systems, coupled with distributed generating sources, enable “microgrid” operation. This allows (healthy) portions of the distribution system that have become disconnected from the power grid to be reenergized and operated as self-contained islands until the normal grid connection is restored. The advanced controls that are implemented as part of level 3 grid modernization will be responsible for balancing energy storage and generating resources with existing load, and for maintaining the proper voltage and frequency at all times while in the microgrid mode of operation.
- *Energy storage-enhanced FLISR.* Conventional FLISR service restoration operations are often blocked due to lack of available capacity on backup alternative sources. With energy storage-enhanced FLISR, the system automatically switches available energy storage units to discharge mode to lower the amount of load that needs to be transferred or to raise the available capacity of backup sources. This enables load transfers for service restoration to be performed that would otherwise be prevented due to loading constraints.

Efficiency Improvement

- *Enhanced volt/VAR control and optimization.* Distributed static VAR resources enable the distribution utility to supply (or absorb) the precise amounts of reactive needed at each feeder location. This will enable the utility to operate at close to near unity power factor at all times. This reduces electrical losses and improves overall efficiency. In addition, intelligent dispatch of DERs enables optimal power flows that further improve efficiency.

Integration of DERs

- *Management of power and voltage fluctuations (dynamic voltage control).* The maximum amount of distributed generation that can be deployed on a given distribution feeder is often limited by the potential drop-off in voltage if the DER output suddenly drops off along the feeder. Advanced control of energy storage units and static VAR sources will mitigate the impact of DER power fluctuations and thereby enable the utility to accommodate more distributed generating resources on any given feeder. In addition, DERs can be actively controlled by the utility to improve voltage regulation, improve VAR support, and (in the future) support microgrid island operation to improve reliability during widespread power outages.

Level 3 Summary

Level 3 builds upon level 1 and level 2 investments to integrate distributed energy resources and enterprise-level application functions into the grid modernization strategy. Table 5.3 summarizes level 3 activities, costs, benefits, and risks.

Table 5.3 Level 3 Activities, Costs, Benefits, and Risks

<i>Level 3 Activities</i>	<i>Costs</i>	<i>Benefits</i>	<i>Risks</i>
As-Operated Model of Distribution system	<ul style="list-style-type: none"> Identify & correct GIS data errors Build and maintain “as operated” model 	<ul style="list-style-type: none"> Enables implementation of numerous level 3 grid modernization applications Adapts to changing distribution system conditions 	<ul style="list-style-type: none"> Missing or erroneous model information can corrupt results of grid modernization applications
Optimal Network Reconfiguration (ONR)	<ul style="list-style-type: none"> Purchase and implement ONR analytical software Train operators and engineers on how to use program 	<ul style="list-style-type: none"> Reduce electrical losses by balancing the load better improve voltage profile improve reliability 	<ul style="list-style-type: none"> ONR recommended switching may change often with frequent feeder changes and new DERs Results may be incorrect if as-operated model contains errors
Model-Driven VVO	<ul style="list-style-type: none"> Purchase and implement VVO analytical software Train operators and engineers on how to use program 	<ul style="list-style-type: none"> Reduce electrical losses Improve voltage profile Peak shaving Improve overall efficiency Adapt to changing feeder conditions Account for DERs in the VVO control strategy 	<ul style="list-style-type: none"> Learning curve for engineers and operators Immature technology Results may be incorrect if as-operated model contains errors Voltage reduction benefits may diminish with time due to changing load characteristics Voltage reduction benefits may not be realized due to existing low voltage conditions
Switching Order Management (SOM)	<ul style="list-style-type: none"> Purchase and implement SOM analytical software Train operators and engineers on how to use program 	<ul style="list-style-type: none"> Generate switching efforts faster and more accurately during emergencies for faster service restoration Switch Order validation improves outage planning (fewer false starts during planned outage work) 	<ul style="list-style-type: none"> Learning curve for system operators and engineers SOM results may be corrupted if as-operated model has erroneous or missing data
Enhanced Fault Location Isolation and Service Restoration (EFLISR)	<ul style="list-style-type: none"> Design, implement and test new software containing “enhanced” FLISR logic 	<ul style="list-style-type: none"> Improved system restoration (fewer blocked restoration efforts) by utilizing available DERs Enhanced model driven solution adapts better to changing feeder conditions 	<ul style="list-style-type: none"> Immature technology Relies on availability of customer owned DERs (less incremental benefit if these are not available)

Table 5.3 Continued

<i>Level 3 Activities</i>	<i>Costs</i>	<i>Benefits</i>	<i>Risks</i>
DER Management & Dynamic Volt-VAR control	<p>Purchase and install:</p> <ul style="list-style-type: none">• New equipment, software and communication facilities for monitoring and controlling DERs, many of which are installed at customer premises• Energy storage, static VAR compensation, and associated controls	<ul style="list-style-type: none">• Mitigate adverse consequences of voltage and power swings caused by Distributed generators with variable output• Enable utility to accommodate more distributed generation on existing feeders• Enable deployment of “microgrids” for critical and worst performing portions of the distribution grid	<ul style="list-style-type: none">• Uses new technology that is unfamiliar to system operators and engineers• Significant learning curve involved• Industry standards needed for voltage control by DERs
Demand Response	<p>Purchase and install:</p> <ul style="list-style-type: none">• Automatic metering infrastructure (AMI)• in home displays• Home automation networks• Demand Response hardware and software at central location	<ul style="list-style-type: none">• Enables peak shaving during critical power shortages• Reduces need to build new generating and transmission facilities	<ul style="list-style-type: none">• DR concept relies in most cases on voluntary customer behavior• DR may not produce the desired amount of power reduction for every event• DR may not produce demand reduction at all specific locations where DR is needed

Source: World Bank.

Grid Modernization Risks

There are significant risks associated with deploying any new technology. Major risks associated with grid modernization are summarized below, along with suggested mitigation strategies for each risk.

Learning Curve for Field Personnel

System operators who are experienced in working with mostly manual paper-driven business processes may have difficulty adapting to an electronic computer-assisted decision support system with a considerable amount of automation. There is a risk that operators will not be very effective and efficient in using the new system.

The following actions are recommended for mitigating this risk:

- Involve the operators in all aspects of the planning and design phases of each application function. This will ensure that each application is designed with the operators' needs in mind, which, in turn, will improve acceptance and buy-in from system operators.
- Provide a comprehensive training program for all operators well in advance of system commissioning. This training program should provide details about how each application works under normal and failure mode conditions. Operators should fully understand how to recognize when something is wrong and what to do about it.
- Utilize a "train-the-trainer" approach in which most of the training is conducted by senior operating staff. This will ensure that the training is presented from an operator's perspective.
- Implement a training simulator to provide each operator with a realistic training environment that does not impact the actual live power system operations.
- For fully automated applications, start with a period of semi-automatic (supervised) operation in which the operator must approve all control actions. Then gradually transition to fully automatic operation with no manual intervention as the operator's comfort level grows.

Information Overload

Substation IEDs are able to supply a wealth of new information pertaining to the loading, performance, and operating status of each distribution asset. There is a strong risk of providing too much information for distribution system operators to digest. As a result, the operators may elect to ignore information. In the worst case, operators may be confused by the new data and make incorrect operating decisions based on their assessment of the available information.

The following actions are recommended for mitigating this risk:

- Only provide information that is "actionable." If no operator response is needed following receipt of a piece of information, then the information is most likely unnecessary.

- Avoid supplying multiple messages that provide the same information. Often distribution SCADA systems will supply several messages that contain the same data. Only the first message is valuable—the second message is a nuisance and contributes to information overload.

Risk of Cyber Attack (“Hacking”)

Several grid modernization applications include communication facilities that enable remote monitoring and control of power apparatus in the distribution substations. Any time communications are introduced, there is increased risk of a cyber-security breach that could result in unauthorized access to sensitive data and control facilities. Unauthorized access to these facilities could disrupt the power supply to end-use customers, damage expensive energized high-voltage power apparatus, and pose a serious safety hazard for the field workforce.

The following actions are recommended to mitigate this risk:

- Develop a security plan early on (not as an afterthought) that will protect remote monitoring and control facilities from unauthorized access.
- Provide suitable physical access controls to buildings and control rooms that house consoles and other equipment that could be used to control the power apparatus.
- Apply encryption and other suitable security measures as needed.
- Prudently apply security measures required for critical infrastructure protection.
- Provide suitable training to inform all system users about the risks associated with a breach of security along with practices to protect sensitive information such as passwords.

Immature Technology

Some advanced software applications associated with grid modernization, such as model-driven volt/VAR optimization, are not yet proven by several years of successful operation in the field. As a result, there is considerable risk that some features may not operate correctly under all circumstances and/or that the software may stop running altogether (“crash”) during live operation.

The following actions are recommended to mitigate this risk:

- Avoid implementing applications that are not fully developed and proven by many years of successful operation in the field. In fact, all applications that require a significant amount of development effort should be carefully scrutinized and tested or avoided altogether if possible.
- Conduct extensive testing of each application to verify that the software is ready for deployment. Testing should exercise all capabilities of each application function, including operation in the presence of bad data.
- Prior to placing the advanced software into operation, conduct a lengthy period of supervised operation in which all control actions identified by the

software must be approved and manually executed by the operator. This will ensure that any failures encountered do not disrupt ongoing operations. This supervised method will also provide an excellent training opportunity for the application.

Summary of Grid Modernization Projects

Tables 5.4 through 5.7 summarize the grid modernization projects that are possible at each grid modernization level. The information provided for each project includes an indicator of the general types of benefits the project provides (improved efficiency, reduced demand, improved reliability, the accommodation of additional DG, and others), along with a cost estimate range for project implementation and a monetary estimate of the range of benefits that may be achieved. All monetary benefits are expressed in U.S. dollars.

Defining a Smart Grid Investment Plan

The previous sections outlined four smart grid modernization levels relevant to the distribution sector. Each level is characterized by the incremental use of more advanced applications to progress toward grid objectives such as improved efficiency, reduced losses, improved reliability, and the integration of renewable energy resources. Utilities may use the descriptions of the four modernization levels to assess where they are in the process and to identify potential new smart grid applications that could help modernize their grid and achieve strategic objectives.

There are many smart grid applications that a utility can choose to promote its modernization level. A utility needs to clearly assess the cost, benefits, and potential risks of implementing new applications to define a sensible investment plan. This section provides guidance on creating such an investment plan to include the specific list of projects to be implemented, their cost, and time frames for their implementation. Creating an investment plan is key to ensuring that the overall budgeting process considers the needs of modernization.

The broad steps toward defining the investment plan are described in the following subsections. Figure 5.14 illustrates the steps in a flowchart format.

Table 5.4 Summary of Grid Modernization Projects (Level 0)

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
0.1	Implement limited FLISR on worst-performing feeders	Equip <i>existing</i> electrically operable switches (reclosers, load break switches) with faulted circuit indicators and loss of voltage indicators; if no switches exist, then these need to be installed (1½ switches per feeder); use local logic to determine when to operate switch in question (no communications required)					Reduce amount of unserved energy; reduce fault investigation and switching time (labor savings)	\$50,000–\$150,000	\$50,000–\$75,000	Assumes feeders have at least one tie to backup source; low-end cost assumes some switches exist; benefits are derived from customer outage cost savings valued at \$10/kWh
0.2	Implement volt/VAR control (including conservation voltage reduction) using local “stand-alone” controllers	Add intelligent electronic device (IED) controllers to <i>existing</i> capacitor banks and voltage regulators and control these devices using local measurements and control logic					Improve feeder voltage profile	\$15,000–\$25,000	\$10,000–\$20,000	Cost estimate assumes two switched capacitor banks are added to existing feeder along with new controller IEDs for capacitor banks and voltage regulators; benefits based on 1% voltage reduction at peak load with CVR factor = 0.7, and poewr factor improvement from 0.9 to 0.94

(continues)

Table 5.4 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
0.3	Apply optimal network reconfiguration (ONR) software	Use off-line ONR software to identify feeder reconfiguration switching that may be performed to reduce circuit and phase imbalance in order to lower electrical losses					Reduce phase imbalance; balance load between feeders	\$2,500–\$5,000	\$2,000–\$4,000	Costs include labor to build models, run ONR program, and perform recommended switching actions (to new equipment); benefits are reduced by losses, which are assumed to be 10%–15% less than present technical losses (estimated at 4% of total energy consumption)
0.4	Implement midline voltage regulators with reverse power flow and cogeneration features	Replace unidirectional voltage regulators with voltage regulators that can respond properly to reverse power flow due to feeder reconfiguration or due to high penetration of distributed generation					Improve voltage profile	\$8,000–\$12,000	\$6,000–\$10,000	Costs include addition of voltage regulator with bidirectional voltage controls (with cogeneration feature); benefits (including the accommodation of more DG) are the savings associated with not having to build new centralized generating units to serve load

Table 5.4 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
0.5	Transition to level 1	Replace electromechanical controllers, protection, and metering devices in the substation with substation IEDs, along with substation remote terminal units (RTUs) or data concentrators that acquire, store, process, and transmit information acquired from IEDs to a control center; also, add reliable and effective communication facilities between the HV/MV substations and the distribution control center (or equivalent centralized facility)					Enable level 1 application functions	\$15,000–\$20,000 per feeder, plus \$200,000 to \$500,000 for basic master station in control center	Specific benefits identified under level 1 projects	Assume 2–3 electromechanical devices per feeder (protective relay, meter IED, and possibly a voltage regulator) need to be replaced with substation IEDs; also need substation SCADA facilities and communication link to control center and SCADA master station in control center

Source: Authors.

Table 5.5 Summary of Grid Modernization Projects (Level 1)

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
1.1	Implement monitoring of protective relays for early detection of feeder outages	Add alarm points and displays for alerting distribution system operators of uncommanded change of state for substation circuit breaker					Detect customer outages before customer calls occur (customer satisfaction improvement)			Cost estimate assumes benefits based on 1% voltage reduction at peak load with CVR factor = 0.7, and power factor improvement from 0.9 to 0.94
1.2	Implement fault location application (distance to fault)	Acquire distance-to-fault information, relay targets, and other event information from protective relay IEDs, and report information to distribution system operator via substation SCADA facilities					Reduce fault investigation time (labor savings)			
1.3	Implement fuse-saving protection scheme	Implement software to enable control room operator to switch between preestablished relay setting groups to apply fuse-saving protection					Eliminate labor costs to replace fuses for temporary faults			
1.4	Implement intelligent bus failover application	Implement software in substation SCADA processor to allow automatic transfer of selected feeders for a substation transformer fault to backup transformer without overloading that transformer					Reduce labor costs for manual switching			

Table 5.5 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
1.5	Implement equipment health monitoring (condition-based maintenance)	Use substation SCADA processor to acquire equipment health data from protective relays and other substation IEDs; available information includes circuit breaker timing and contact wear, substation battery performance, and device counters					Lower equipment maintenance and repair costs by transitioning from routine scheduled maintenance to “as needed” maintenance			
1.6	Implement SCADA “rule-based” volt/VAR optimization system	Use substation SCADA processor to control substation voltage regulator and substation capacitor bank for improved volt/VAR control (control still limited to substation devices due to lack of communication with field devices—level 2)					Monitor condition of substation volt/VAR equipment for early failure detection			Benefits versus stand-alone controller approach: can use on line power flow (project 1.7) to identify electrical conditions at feeder extremities and thereby maximize benefits of volt/ VAR optimization by operating closer to limits; also has early failure detection, ability to modify VVO objective based on system conditions, ability

(continues)

Table 5.5 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
1.6 Cont.										to disable following feeder reconfiguration or other abnormal condition. Benefits based on 2% voltage reduction at peak load with CVR factor = 0.7, and power factor improvement from 0.9 to 0.94.
1.7	Implement an on-line power flow to be used by distribution system operator	Implement an on-line power flow program that uses measurements from the head end (substation end) of the feeder to compute electrical conditions at all feeder locations (online power flow requires an “as-operated” model of the electric system to operate correctly)					Enabler for many advanced distribution applications—greatly improved visualization for feeder locations at which no sensors exist		No direct tangible benefits, but OLPF enables advanced applications	Cost includes OLPF software purchase and implementation, model building, and maintenance; no direct tangible benefits

Table 5.5 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
1.8	Implement predictive fault location application function	Add short circuit analysis software that uses fault magnitude from substation IED to pinpoint fault location					Reduce fault investigation time (labor savings)			Cost includes software purchase and implementation costs; benefit includes 5% to 10% improvement beyond what protective relay distance-to-fault calculation supplies
1.9	Detection of reverse power flow at substation end of feeder due to high penetration of DG	Monitor real and reactive power flow at the head end of the feeder to detect possible adverse consequence of high penetration of DG, such as reverse power flow and high phase imbalance								Benefit is that the allowable penetration of DG on a given feeder may increase due to improved capability to monitor some of the potential adverse consequences of high DG penetration

(continues)

Table 5.5 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
1.10	Transition to level 2	Add a communication network for supporting two-way communications between substation and field devices for remote monitoring and control of feeder equipment					Enables level 2 functions and projects	\$15,000 to \$30,000 per feeder	Specific benefits identified under level 2 projects	"Transition" costs include addition of two-way communication facilities between control center/substation and feeder devices (switchgear, voltage regulators, switched capacitor banks, distributed sensors) installed outside the substation fence. Estimate based on communication facilities to 5–10 field devices per feeder, plus necessary repeaters, collectors, data concentrators, routers, and other equipment needed to implement the communication network

Source: Authors.

Table 5.6 Summary of Grid Modernization Projects (Level 2)

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
2.1	Implement fault location, isolation, and service restoration (FLISR) application	Add automated switches, fault detectors or faulted circuit indicators, and software for implementing the FLISR functionality					Reduction in manual switching activities and fault investigation time (labor savings)	\$100,000–\$150,000		Costs assume 2 to 3 new switches per feeder, communication system interface, and fault detectors, plus FLISR software for substation or master station (software costs shared across many feeders); outage duration improves by 50% to 60%. Cost does not include cost to add backup source to existing feeder.
2.2	Advanced substation bus failover	Add control of feeder switches to the intelligent bus failover application; feeders that cannot be transferred to remaining healthy transformer due to loading constraints will be switched to adjacent feeders using DA switches					Defer adding substation capacity to provide firm capacity (defer capital expenditures)	\$10,000–\$15,000		Cost included additional software only; necessary switches and communication facilities included in level 2 transition costs

(continues)

Table 5.6 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
2.3	Coordinated volt/VAR control with conservation voltage reduction	Add control of switched capacitor banks and mid-line voltage regulators located out on the feeder (outside the substation fence) to the volt/VAR optimization algorithm					Improved voltage profile			Costs include addition of communication interfaces to volt/VAR devices located out on the feeder (controllable capacitor banks and voltage regulators added during project 0.2). Benefits include coordinated control of volt/VAR devices located in substations and out on feeder.
2.4	Improved on-line power flow	Improve the accuracy of results produced by on-line power flow (project 1.7) by using measurements acquired from feeder devices and distributed sensors					Enabler for many advanced distribution applications; greatly improved visualization for feeder locations at which no sensors exist		No direct tangible benefits, but OLPF enable advanced applications	Cost includes labor to modify feeder models used by OLPF

Table 5.6 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
2.5	Optimal network reconfiguration	Add automatic switching to ONR application (project 0.3); this will enable utility to more frequently change the feeder configuration to accomplish load-balancing objectives					Reduction of manual switching activities (labor savings) by using remote-controlled switches for feeder reconfiguration			Cost includes software modifications; automated switches and communication facilities added during previous projects. Benefits include loss reduction and improved phase balance.
2.6	Monitoring and transfer tripping of DG units	Use two-way communication facilities to monitor and control the output of larger-scale customer-owned distributed generation					Improved power flow results due to accurate measurement of DG output			Costs include monitoring and control facilities plus communication interface at large-scale DG units out on distribution feeders. Benefits include improvement in allowable DG on feeder, and operating advanced DA applications closer to established operating limits.

(continues)

Table 5.6 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
2.7	Transition to level 3	Implement active control of distributed energy resources (DG, energy storage, demand response devices) located out on the feeder and at customer sites (beyond the meter)							Specific benefits identified under level 3 projects	Costs include implementation of controllers and associated communication interfaces at DERs. Assume that communications will be done through the Internet or through AMI communication network (RF mesh or other media).

Source: Authors.

Table 5.7 Summary of Grid Modernization Projects (Level 3)

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
3.1	Microgrid operation	Implement a microgrid energy management system that is able to support grid-connected and island modes of operation for the most critical loads; use this system to manage the operation of available distributed energy resources					Increased revenue from participation in market operation	Cost of microgrid management system (hardware and software); add switchgear to switch to island mode	Resiliency benefit for critical loads is intangible; DR market benefit is about \$40,000 per MW per year	Costs include microgrid master station (hardware and software) for managing available DERs to achieve specific business objectives; benefit include demand response during peak load periods and ability to serve critical loads during power grid outages (intangible benefit)
3.2	Energy storage-enhanced FLISR	Deploy enhanced FLISR software that uses energy storage capabilities to reduce occurrences of blocked transfers by “standard” FLISR applications						Enhance standard FLISR software (see project 2.1)	Fewer blocked FLISR load transfers (assume 10% blocked without storage; 5% blocked with storage)	Costs include software additions to incorporate management of available energy storage in FLISR application software. Project costs do not include installation of energy storage (assume existing storage is used). Benefits include fewer blocked load transfer during FLISR operations.

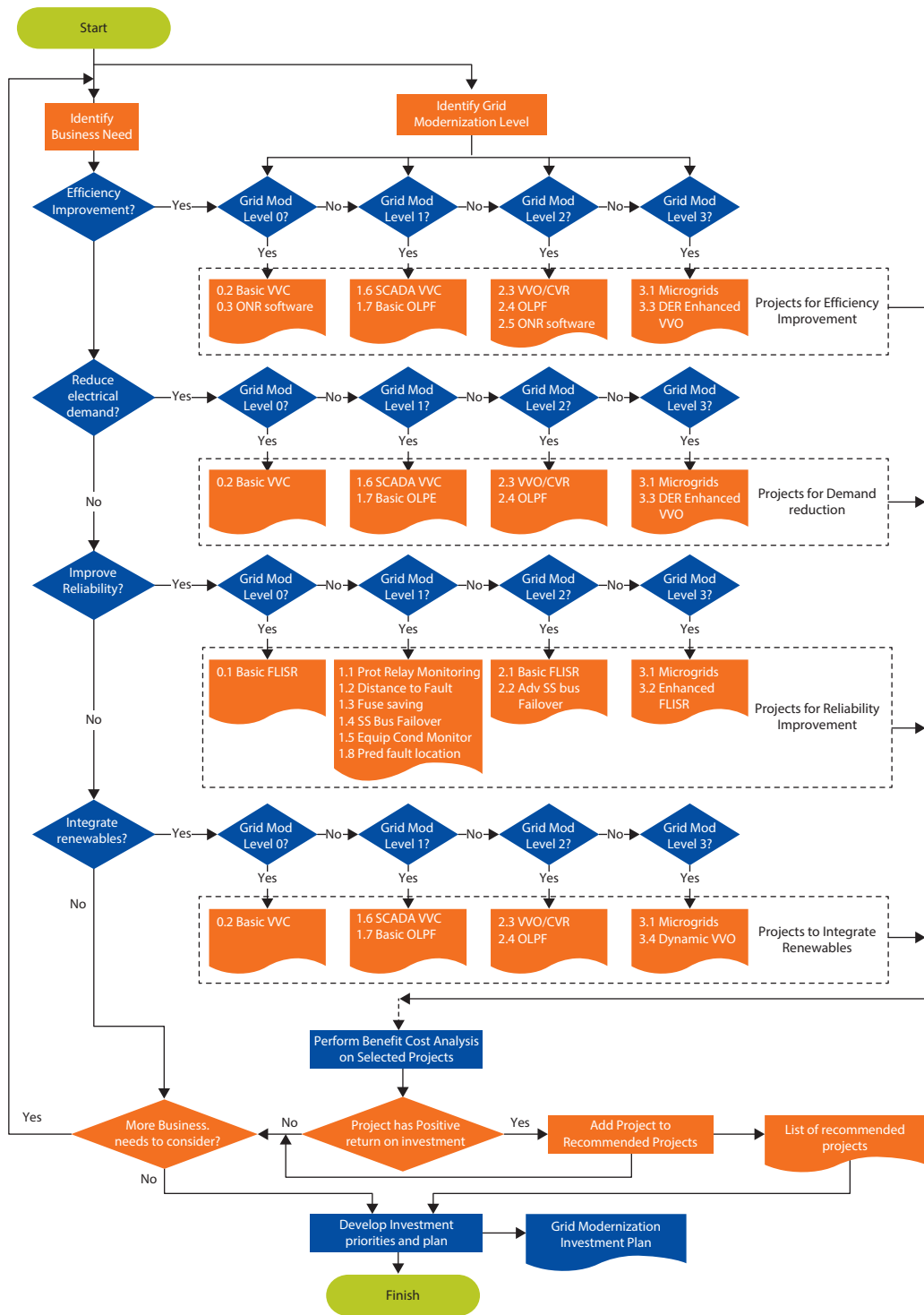
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Table 5.7 Continued

Project Number	Project Name	Project Description	Benefit Type					Estimated Cost Range (\$/feeder/year)	Estimated Benefit Range (\$/feeder/year)	Comments
			Improve Efficiency	Reduce Demand	Improve Reliability	Integrate Renewables	Other			
3.3	DER-enhanced volt/VAR control and optimization	Use smart inverter-based distributed energy resources to improve volt/VAR optimization on a given feeder					Reduce wear on electro-mechanical volt/ VAR devices	Implement interfaces to smart inverters; add software to include smart inverter control in VVO algorithm	Operate VVO closer to operating limits to gain maximum benefit	
3.4	Dynamic volt/ VAR control	Use distribution static VAR compensators and/or smart inverters to mitigate voltage fluctuations and power swings due to variable output from distributed renewables					Improve voltage quality and reduce wear on electromechanical switching devices (LTCs, switched capacitor banks)	Add Dstatcom to distribution feeder with high penetration of distributed renewables	Accommodate more DG (20% or more) on given feeder by addressing voltage and power fluctuations	Costs include installing distribution static VAR compensator that can respond rapidly to voltage fluctuations. Communications not required as these devices operate autonomously. Benefits include ability to accommodate more distributed renewables (wind, solar) on a given feeder

Source: Authors.

Figure 5.14 Flowchart for Creating an Investment Plan



Source: World Bank.

Step 1. Identify Business Requirements

There is no single investment strategy for grid modernization that applies to all electric distribution utilities (that is, no “one size fits all”). This is because pressing operating needs and challenges differ from utility to utility, due to differences in customer expectations, regulatory climate, geographic constraints, available labor and financial resources, economic conditions, and other such factors that are relevant to distribution grid modernization. The identification of business requirements must address the issues facing the electric distribution utility on a day-to-day basis as well as the unique challenges posed by emergencies, such as widespread storms and natural disasters. An effective grid modernization investment strategy will address the issues and challenges faced by a specific utility.

The first step toward creating a grid modernization investment strategy is to develop a thorough understanding of the key business requirements that apply to the electric utility in the short term (the next three to five years) and the long term (beyond a five-year horizon). This will provide a foundation upon which the specific functional and technical requirements of distribution grid modernization may be based.

While business requirements vary from utility to utility, common objectives include the following:

- *Improve efficiency*—specifically, to satisfy a given amount of electrical load using less electrical energy. Efficiency programs for electric distribution utilities are usually focused on reducing losses (technical and nontechnical) and lowering overall energy consumption without actually shedding any load.
- *Reduce demand*, with a focus on mechanisms to lower the electrical power requirements during peak loading intervals, when electrical demand is often considerably higher than the average demand. This is an especially important business requirement, because the power generation and delivery infrastructure must be able to serve this load even though the peak demand may last for a only small portion of the day.
- *Improve reliability*, with a focus on the frequency and duration of power outages on the electric distribution system. Since most service disruptions on the electric distribution system result in power outages for one or more customers, this requirement is tied closely with overall customer satisfaction. Establishing microgrids to serve critical loads during widespread power outages is becoming a key element of the grid modernization strategy of many electric utilities.
- *Accommodate distributed generation*. In an effort to reduce emissions from fossil-fuel-fired central generating units, many jurisdictions are seeking to deploy clean energy-generating resources (solar, wind, and so on) on their electric distribution systems. Such “renewable” generating resources may produce abnormal electrical conditions on the distribution feeders (for example, reverse power flows, voltage fluctuations) that usually limit the

amount of such generation that may be implemented. Hence, a growing number of electric distribution utilities are deploying grid modernization measures to allow increased amounts of DG without adversely impacting power quality.

Other business requirements that may be addressed by distribution grid modernization include safety, security, workforce productivity and training, and distribution asset management and utilization.

Understanding the key business requirements should begin by interviewing the persons who “own” the problems: the electric utility executives. These senior-level managers will furnish information on the most important business problems that are facing the utility company as well as a vision for future long-term needs. In addition to management perspectives, the needs of persons who are responsible for planning, designing, constructing, maintaining, and operating the electric distribution system must also be well understood. To this end, interviews should include representatives of the departments that are responsible for performing these duties.

Step 2. Identify the Current Level of Grid Modernization

The grid modernization strategy should leverage the electric distribution utility’s existing assets to the fullest extent possible. This will help ensure that the modernization plan is practical and possible using available resources. Therefore, gaining a thorough understanding of where the organization is today is an important first step toward grid modernization.

It should be noted that the level of grid modernization may vary at different locations across an organization’s service territory. For example, there may be “pockets of automation” where some grid modernization technologies have been demonstrated (that is, pilot projects), and newer technologies installed in only a small portion of existing facilities. The overall strategy should not be based on the assets of only a small number of substations and feeders, but rather on the facilities and operating practices that exist across a majority of substations and distribution feeders.

The following is a list of guidelines that may be used to determine the current level of automation.

The grid is at *level 0* (manual control or local automation) if the following conditions apply to a majority of substations and feeders:

- The majority of substations are staffed on a routine basis by operating personnel who monitor the status of power apparatus and operate the equipment manually when necessary (this does not include personnel stationed only during construction and maintenance activities or during local emergencies).
- Some automatic control devices (line reclosers, capacitor bank controllers, voltage regulators, and so on) may be found on electric distribution feeders, but their control decisions are based solely on local measurements.

- There are no permanent data communication facilities between power apparatus and supporting facilities or substations/feeders and the control centers associated with these facilities. Voice-only communications may exist.
- The majority of protective relays and local controllers are electromechanical or solid-state electronic devices (not IEDs) and are not connected to any communication facilities (including dial-up facilities).

The grid is at *level 1* (substation communication and automation) if the following conditions apply to a majority of substations and feeders:

- Most of the protective relays, controllers, meters, and other instruments that are currently installed in distribution substations (HV/MV) are IEDs.
- Most HV/MV substations include communication facilities and remote terminal units (RTUs or equivalent devices) that support remote monitoring and control of the substation power apparatus.
- Most HV/MV substations are not permanently staffed for routine operational purposes.
- Some automatic control devices (line reclosers, capacitor bank controllers, voltage regulators, and so on) may be found on electric distribution feeders, but their control decisions are based solely on local measurements.
- No facilities exist for communicating with feeder devices.

The grid is at *level 2* (monitoring and control of feeder devices) if the following conditions apply to a majority of substations and feeders:

- Most of the protective relays, controllers, meters, and other instruments that are currently installed in distribution substations (HV/MV) are IEDs.
- Most HV/MV substations include communication facilities and RTUs (or equivalent devices) that support remote monitoring and control of the substation power apparatus.
- Most HV/MV substations are not permanently staffed for routine operational purposes.
- Some automatic control devices (line reclosers, capacitor bank controllers, voltage regulators, and so on) exist out on the electric distribution feeders.
- Some facilities exist for handling two-way data communications between feeder devices and the associated control center. These facilities may be used for remote monitoring and control of feeder devices.

The grid is at *level 3* (active DER control/demand response) if the following conditions apply to a majority of substations and feeders:

- All of the conditions specified for grid modernization level 2 apply.
- Some distributed generating units (utility owned or customer owned) are equipped with remote monitoring and control facilities that may be used

to manage the output of the DG unit from a utility-operated control center.

- Some noncritical loads at customer premises (programmable thermostats, hot water heaters, and so on) may be controlled. Most of the protective relays, controllers, meters, and other instruments that are currently installed in distribution substations (HV/MV) are IEDs.

Step 3. Generate a List of Potential Projects

In this step, the organization should develop a list of potential (candidate) grid modernization applications that appear to have technical merit in addressing the organization's needs and strategic goals. Such applications should be analyzed further to determine if their expected benefits outweigh the costs required to implement and sustain them.

Tables 5.4 through 5.7 list specific projects that can be accomplished at each level of grid modernization. For example, table 5.4 lists recommended projects for grid modernization level 0 (manual control and local automation), including projects that can provide valuable business benefits without additional communication facilities or other major infrastructure improvements. Project 0.2 implements a basic form of VVO (CVR) using existing stand-alone controllers, for example, while project 0.5 involves a transition from level 0 to level 1 (substation communications and automation).

Table 5.5, focused on level 1, lists projects using IEDs and SCADA facilities for substation monitoring and control. The 10 recommended projects offer numerous ways to exploit the information supplied by the latest generation of substation IEDs, and one project involves transitioning to level 2 (monitoring and control of feeder devices). Several projects can be accomplished for almost no incremental cost, such as project 1.5, which involves using IED data to implement a reliability-centered maintenance program.

Similarly, tables 5.6 and 5.7 list project lists for electric utilities that are currently at grid modernization level 2 and level 3 (active DER control and demand response).

In each table, a brief project description is followed by general types of functional benefits (that align with the strategic goals of planning step 1). The table column under the benefit is shaded if the project makes a significant contribution to the electric distribution network's aim to:

- Improve efficiency by, for example, reducing electrical losses and/or lowering energy consumption for a given load or amount of work.
- Reduce demand by, for example, executing demand response events, running distributed generators, and lowering the voltage or reducing losses during peak load conditions.
- Improve reliability by reducing the average frequency or duration of outages experienced by end-use customers. This can be accomplished by pinpointing fault location (and thus shortening investigation time), performing automatic

sectionalizing and service restoration, and operating in island mode as a “microgrid” when major widespread outages occur.

- Integrate renewables by managing voltage problems caused by reverse power flows and voltage fluctuations that are attributable to distributed renewables.
- Other benefits, including deferring capital expenditures for capacity additions, reducing maintenance costs for expensive substation equipment, and labor savings.

Step 4. Undertake a Cost/Benefit Analysis

Once potential grid modernization applications have been identified, it is necessary to determine if the cost to implement each application and the associated risks are outweighed by the expected benefits over the life of the investment (10–15 years). As part of this step, the organization should perform a cost/benefit analysis and risk assessment of potential grid modernization applications, then develop a list of applications recommended for implementation.

Tables 5.4 through 5.7 provide ranges of specific benefits and costs for each proposed project. The cost figures are expressed in units of U.S. dollars per distribution feeder. The benefit range indicates the cost range per feeder on an annual basis over the life of the project.

The following methods were used to convert functional benefits into monetary terms:

- Reliability improvement benefits were converted into monetary benefits using an assumed customer cost of outage (for example, US\$10 per kilowatt-hour, kWh).
- Efficiency improvements were converted to dollar amounts using an assumed marginal location pricing (for example, US\$50 per megawatt-hour, MWh).
- Demand reduction benefits were converted to dollar amounts using the average cost to add new centralized generation units to serve that demand level (for example, US\$50,000 per megawatt of new capacity).
- Benefits that allow the utility to accommodate renewables were monetized using the capacity cost of centralized generation displaced by the distributed renewable (for example, US\$50,000 per megawatt).

Step 5. Create an Investment Plan

The final step is to create an investment plan for the recommended applications—using limited organizational resources (including labor and financial resources) in an optimal manner, to achieve maximum payback on investment as quickly as possible, with minimum risk. In almost all cases, a phased implementation strategy is best. Projects that promise the greatest benefits should be completed at the earliest possible date. Also, “foundational” (enabling) elements (communication facilities, controllable devices, and so on) should be put in place to serve the needs of the application functions to be implemented during later phases.

Modernizing the Grid: Gradual Transitions versus Leapfrogging

The previous section describes how an electric utility may gradually progress to a higher grid modernization level. Most utilities in developed countries have followed this gradual progression by implementing the best available technologies at any given time. But it is not necessary for a utility that is currently using electromechanical technology from the 1970s or earlier to gradually modernize by first installing 1980–90 technology (solid-state devices), and then replace these units at some later date with 21st-century IEDs. Utilities in developing countries that have not completely built out their electric system may elect to bypass some of the traditional modernization steps through a process called “leapfrogging,” which is described in the following subsections.

A Gradual Transition to Smarter Grids: Developed Countries

Many electric utility companies (especially those in developed countries) have been delivering electric power to residential, commercial, and industrial customers for decades. In most of these cases, utility companies started out by supplying electric power to customers in the most densely populated areas of their service territory: the cities and surrounding suburban areas. The electric power infrastructure for these electric utilities has evolved significantly over the years to meet the growing expectations of their consumers. Energy consumption has risen dramatically over the years due to the almost universal acceptance of electrical appliances; an increase in the use of central heating, ventilation, and air conditioning (HVAC) among residential customers; and new types of loads including (most recently) electric vehicles. In addition to growing to meet new energy demand, the power delivery infrastructure has been expanded geographically out from urban areas to all but the most remote rural locations.

Electric utilities have met the growth of electricity consumption by increasing the capacity of the existing power delivery infrastructure and by adding new substations and extending transmission and distribution lines to reach new customers in rural areas far from the metropolitan load centers. In most cases, this transition has taken place gradually over several decades, and has been supported by government agencies such as the U.S. Rural Electrification Administration.

As new substations and feeders were built, the electric utilities used the best available technologies at the time. Distribution substations and feeders that were constructed in the 1970s and earlier used mostly electromechanical devices for protective relays, meters, and controllers because that was the only technology available at the time that was field proven and accepted by somewhat conservative electric utilities. Few if any distribution substations were equipped with SCADA and communication facilities, because these technologies were expensive at the time and deemed unnecessary for distribution systems.

As new communication and control technologies were developed and became widely accepted, electric utilities began to deploy these technologies in new

substations and in existing substations during capacity expansion projects. And when the older-style electromechanical relays failed, these devices were often replaced by the latest technology components, including microprocessor-based IEDs. In the past five to ten years, major technology advances have occurred in communication systems, thus making it cost-effective to deploy remote monitoring and control facilities for substation equipment and devices located out on the feeders themselves.

Since growth patterns for electric utility companies have not been uniform across developed countries, some utilities have not progressed beyond the early days of electromechanical components and have little or no remote management capabilities. But it is expected that when older-style components need replacing, they will be replaced with the latest technology IEDs, thus “leapfrogging” the natural technology-driven progression to modern devices.

The Case of Developing Countries

Electric utilities in developing countries generally do not have the same decades-long history of growth and geographic expansion. Many electric distribution utilities continue to rely on electromechanical components that were installed many years ago. Most organizations rely exclusively on manual, paper-driven business processes with almost no automation or remote monitoring and control capabilities. In addition, the electric power delivery infrastructure has not been sufficiently built out to provide reliable continuous electricity supply to communities that are far from major cities.

While this document has presented a strategy for progressing gradually from manual business processes (level 0) to increased levels of grid modernization (levels 1 to 3), it is unnecessary to proceed one step at a time to the next-highest level. In fact, it is possible to “leapfrog” several levels and go directly from grid modernization level 0 to level 2 or 3. This is comparable to transitioning from having no telephones to implementing cellular telephone technology without going through the tradition steps of building out the infrastructure needed to support a wired telephone system.

As an example, it is possible for a utility company that is generally at grid modernization level 0 or level 1 to implement a microgrid/demand response system, which is identified in this report as a grid modernization level 3 project. Most electric utilities in developed countries view the microgrid as a mechanism to supply critical customers when the existing power delivery infrastructure experiences massive damage. For utilities in developing countries, meanwhile, microgrids can be viewed as an effective mechanism to supply power to isolated communities that do not have reliable continuous electricity supply. As in the case of cellular phones, the microgrid example allows utilities to “leapfrog” the traditional step of building a wired power delivery infrastructure. The level 3 microgrid project will use advanced metering, demand response, and available communication facilities (such as the Internet), all of which are level 2 projects, to accomplish the microgrid objectives.

There are other steps that a utility at grid modernization level 0 or 1 can take to facilitate an eventual transition to higher levels of grid modernization:

- If a manual feeder line switch needs to be installed or replaced, install an electrically operable switch that can later be retrofit with a communication interface to accomplish level 2 projects such as FLISR.
- Electromechanical substation protective relays that fail should be replaced with a functionally equivalent IED that will be able to support future applications at levels 1, 2, and 3.
- Advanced metering facilities should support two-way communications, thus enabling the future addition of DR capabilities.
- Communication facilities that are installed to support new metering systems should be designed to also support communication with distribution automation devices (line switches, voltage regulators, capacitor banks, and distributed generating units) using standard interfaces (for example, IPV6). This will ease the implementation of FLISR, VVO, and other level 2 and 3 projects.
- Inverter-based distributed generating units (for example, rooftop solar panels) should be equipped with smart inverters that may be used to support a wide range of advanced projects, such as microgrid management, DER-enhanced FLISR, and DER-enhanced VVO.

More on Leapfrogging

Analyzing the grid modernization levels helps clarify a logical path to implementing grid modernization, beginning with substation modernization (level 1), followed by modernization of the distribution feeders (level 2), and finally the addition of advanced application functions (level 3).

As noted in the previous subsection, it is not necessary to implement the entire set of level 1 grid modernization activities before proceeding with level 2 modernization. In fact, a very effective strategy is to move forward with some level 2 activities following the partial completion of level 1 activities. For example, it is possible to proceed with SCADA rule-based volt/VAR optimization (a level 2 activity) following the implementation of feeder protective relay IEDs (one of the numerous level 1 activities). This will enable the utility to derive some of the lucrative level 2 benefits, such as electrical loss reduction, before fully completing all of the level 1 activities. Similarly, it is possible to implement one or more of the level 3 activities prior to completing level 1 and level 2. Level 3 functions such as switch order management (SOM) may be implemented before sensors, controllers, and automated switches are added as part of levels 1 and 2.

A regional implementation strategy may also vary the modernization activities implemented across a utility's total service area, customizing them to meet various needs. One example of this approach is to invest heavily in the worst-performing service areas in order to improve their efficiency and reliability. In this case, the worst-performing areas may rapidly advance to grid modernization level 3 to gain the maximum benefit for the grid modernization investment.

Regulatory and Financing Issues

Fully realizing the benefits of grid modernization does not depend strictly on technology applications. Technology applications require enabling environments for their deployment—and the assurance, among other things, that (i) companies have the incentive to pursue technologies that improve grid performance, (ii) the technologies introduced comply or surpass technical requirements for their performance on the grid, and (iii) vendors are neutral, and different technologies can communicate with one another, allowing network modernization to progress and not stall.

Regulatory aspects will be more or less important depending on the current level of grid modernization and the technology applications that are being pursued. Deploying one smart grid vision may require completely different regulations than another vision. For example, deploying certain technologies (such as for storage) may require new add-ons to current regulatory arrangements so that storage providers understand the market or cost-recovery mechanisms that will make their business proposition valuable. Similarly, a grid that should enable vast amounts of PV requires defining clear performance requirements for such technologies to achieve the common goals of maintaining grid reliability and service quality.

This chapter does not intend to be a comprehensive review of all regulatory aspects related to smart grid deployment, but provides some suggestions that should help identify when special requirements may be needed, and provides further references.

Cost Recovery and Funding

Funding grid modernization projects, programs, road maps, and plans requires careful consideration of the regulatory aspects related to recovering investments. Grid modernization should be an integral part of the capital expenditure program of utilities. Technologies that have been proven and largely tested in other

places and whose risk of deploying somewhere else are low should be part of conventional investment plans and the cost-recovery base. Since a key function of the regulatory process is to make sure investments are efficient, regulators should always question whether the utility is making enough effort to identify modernization possibilities that can clearly benefit consumers. Cost-efficiency principles should not be applied in narrow ways that seek to immediately reduce capital costs; instead, the long-term benefits of modernization should be considered.

The cost of service regulations should include the cost of proven, lower-risk smart grid technologies as part of utilities' regular capital expenditure programs.

Not all smart grid applications should require special regulatory treatment from the cost-recovery point of view. The modernization costs of basic (proven) technologies should be part of utilities' capital expenditure programs and, with that, the costs of deployment may be transferred to tariffs. This is especially true for those modernization activities that include applications largely tested in other markets and for which the costs and benefits are robust and the risks are rather limited. For example, reducing losses may require the introduction of automated capacitors. This technology has been largely tested, and while it may not be in use in a country, it has easily verifiable and robust benefits beyond its costs.

As discussed in previous chapters, not all utilities start at the same modernization level. A first step toward modernization might, for example, focus on integrating technologies that are well tested in various environments. Thus, recouping costs would not require any special regulatory process beyond widely available cost-recovery models.

More advanced, less tested, or larger smart grid deployments require careful attention from the regulatory and funding perspective.

Investments in smart grid programs can involve thousands of high-voltage components (voltage regulators, switchgear, capacitor banks, and so on) and possibly millions of secondary devices (meters, controllers, protective devices, sensors, and so on). In addition, they may involve new technologies and regulations (for example, real-time pricing via smart metering programs) that have not been tested or piloted and whose risks of not achieving expected benefits may be high. Some smart grid deployment may therefore require special regulatory treatment to ensure costs are rightly allocated. Untested technologies or innovations may require special funding vehicles such as government grants.

Programs that involve large reductions in the demand served by utilities, meanwhile, may require special regulatory treatment to ensure service providers remain viable despite decreasing energy sales. Highly advanced levels of modernization or more ambitious smart grid visions may require an alternative regulatory framework. A number of cost-recovery and performance incentive programs may be needed to ensure utilities have the incentive to apply new technologies that will lead to lower energy sales. The National Action Plan for Energy Efficiency lists several mechanisms that go beyond traditional cost-recovery options:

- *Performance incentives.* Providing financial incentives to a utility to perform well in delivering energy efficiency can change the business model by making efficiency profitable rather than merely a break-even activity. The three major common types of performance incentives center on:
- *Performance targets.* A percentage of the total program budget is set aside to reward the achievement of specific metrics (percentage of losses, average outage duration, and so on) of the smart grid program.
- *Shared savings.* Utilities are given the opportunity to share, with rate payers, the net benefits resulting from successful implementation of energy efficiency programs.
- *Lost margin recovery.* This mechanism is designed to estimate the revenue margin that might be lost due to a successful energy-efficiency program, and compensate utilities for any resulting reduction in sales. But the incentive does not change the linkage between sales and profit.

Smart Grid Standards and Interoperability

The electric grid includes many high- and medium-voltage devices and associated protection and control equipment that are expected to maintain acceptable electrical conditions throughout the distribution system during periods of normal and emergency operation. In the past, this fundamental operating goal could be achieved effectively using stand-alone protection and control devices that were able to determine and initiate appropriate responses to load changes and electrical disturbances using “local” measurements made at the device itself. Coordination between these devices was achieved through time delays and other such measures that did not require physical integration of individual components.

Today, electric distribution utilities are seeking to satisfy the more stringent needs of electricity consumers and to maintain optimal electrical conditions at all times. Achieving these objectives in today’s operating environment is far more challenging due to the growing presence of distributed generators powered by variable renewable energy sources (especially solar PV and wind power sources). Achieving optimal performance in this environment requires a level of performance that can only be achieved through fully coordinated operation of intelligent and flexible protection and control devices that are able to adapt to meet continuously varying system-level conditions and varying operating objectives. A new generation of communicating sensors and control devices is needed to satisfy the needs of today’s smart grid, along with a reliable, robust, and secure communications infrastructure that allows this new class of protection and control devices to exchange information and “interoperate.”

Interoperability¹—the ability of diverse systems and their components, supplied by a plethora of manufacturers, to work together—is vitally important to the performance of the smart grid at every level. It enables integration, effective cooperation, and two-way communication among the many interconnected

elements of the electric power grid. To achieve effective interoperability, a unifying framework of interfaces, protocols, and other consensus standards is needed.

The deployment of various smart grid elements—including smart sensors on distribution lines, smart meters in homes, and widely dispersed sources of renewable energy—is already under way and will be accelerated as a growing number of electric utilities worldwide proceeds to implement their smart grid strategy. Without standards, there is the potential for technologies to interoperate poorly in a multivendor environment, to become obsolete prematurely, and to be implemented without measures necessary to ensure security. To meet this need, international standards bodies, including the U.S. National Institute of Standards and Technology (NIST), are coordinating the development of a framework that includes protocols and model standards for information management to achieve the interoperability of smart grid devices and systems.

Standards have been part of the historical development of technology in the electricity sector. In many cases, existing standards will suffice to deploy many applications that are already well proven, but may not be in use in all countries, given their modernization level. For example, there are numerous protocols and standards that have been used very effectively in SCADA systems that require integration and interoperability among a wide variety of protective relays, intelligent controllers, and communicating sensors associated with electric distribution transformers, switches, and other conventional power apparatus. Examples include DNP3 (IEC 61850-5) and the IEC 61850 set of standards. The ANSI C12.19/IEEE 1377/MC12.19 standards and data models are becoming widely accepted for use with advanced metering systems, which are a great tool to protect the revenue of utilities and to incentivize demand response.

In other cases, however, new standards must be developed for the new interactions made possible by the smart grid. For example, important smart grid interoperability standards that are still under development include the following:

- *Demand response.* OpenADR is going through the Smart Grid Interoperability Panel (SGIP) process, with the expected outcome that the two defined profiles of OpenADR 2.0 will be entered into the SGIP Catalog of Standards. In parallel, the OpenADR Alliance is working with the International Electrotechnical Commission (IEC) with a mutual objective to develop an international automated DR standard.
- *Smart inverters.* To achieve the kind of advanced grid functionality required to accommodate higher levels of solar energy, smart inverters will need to include a range of automated control capabilities that will help smooth out potential grid fluctuations. Various industry stakeholders are currently involved in the development of the necessary international standards and regulatory compliance testing protocols that will help ensure the transition to an advanced, stable grid.
- *Electric vehicle charging standards.* As more and more EVs enter the fleet, and annual sales continue to increase, the question of charging—and charging

protocols—becomes ever more critical. While we are still in the early days of the EV adoption cycle, it is important to sort this out. At the end of the day, EV mobility will depend upon the build-out of a network of charging stations. Drivers will want to be able to charge at home, but to overcome range anxiety they will want to charge on the road as well—quickly and conveniently.

- *Communication standards.* Interoperability in most smart grid networks is achieved in the upper layers of the protocol stack. IEC 60870-5-101/104 and DNP3 are the most commonly used SCADA protocols used to implement distribution SCADA and automation applications. IEC 61850 is also beginning to see limited use in DA systems and more profound use in high-voltage applications, especially outside the United States.
- *Internet Protocol (IP).* Networks are used extensively in modern DA networks to provide end-to-end connectivity from devices in the field to back-office systems. IP can carry a variety of protocols yet allow the utility build a single network. This eliminates the need for complex or proprietary protocol gateways, allows the network designer a great deal of flexibility, and is popular since IP is widely accepted and understood. Furthermore, DA protocols can continue to evolve over time, but the supporting network does not need to be replaced as long as IP continues to be the bearer service. But while IPv6 has made significant inroads into the AMI application space, many smart grid devices are still largely the domain of IPv4.

There are hundreds of standards; when analyzing potential applications, it is important to understand if the particular technology will lock in future developments. Researching which standards may be available to help ensure applications deliver their full benefits is a critical step. There are standards that apply for the generation segment, the distribution segment, and system operations across different consumption areas. The sources available, such as the Smart Grid Standards Map from the National Institute of Standards, can serve as a good platform to identify related standards that may be of importance to each potential smart grid application.

Note

1. The definition of the National Institute of Standards in the United States. Similar definitions apply elsewhere.

Planning Practices to Further Benefit from Grid Modernization

Advanced monitoring and control facilities provide many new opportunities for power system planners. Innovative uses of these facilities will enable planners to postpone capacity additions and solve complicated power quality problems. New planning tools and methods will be needed to enable planners to exploit the smart grid facilities.

This chapter outlines the methods and tools used by distribution system planning engineers across various grid modernization facilities. Capacity planning has always been a major responsibility of the planning engineer. In the past, planners usually addressed growing loads with new facilities (substations, new feeder positions, line upgrades). Grid modernization has provided a number of new ways to address growing loads, including peak-shaving techniques (demand response, voltage reduction), optimal network reconfiguration, and other techniques that enable the planner to postpone adding new power system facilities.

Planners must properly account for the presence of new DERs out on the feeders, which may (or may not) help meet the peak load. If DERs can be counted on during peak load conditions, then new construction may be postponed. But if DERs include a high penetration of (potentially variable) renewables or do not largely coincide with peak demand, their contribution to peak shaving will largely be limited.

The impact of zero net energy homes on capacity planning must be considered. With zero net energy, utilities must provide capacity to serve each customer, but may receive no net revenue from kilowatt-hour sales. Planners are responsible for providing advanced controls for dealing with the power swings and voltage fluctuations associated with renewables to mitigate unacceptable impacts on power quality.

More networking may be needed to enable higher loading on existing feeders. Software tools used by distribution planning engineers must include many new features to assist in addressing the issues posed by grid modernization. Such features are described on the following pages.

DER Analysis (Steady-State and Dynamic Studies)

The capability to conduct combined steady-state and dynamic studies for distributed energy resource (DER) impact and integration analysis is arguably the most urgent need of distribution utilities. High penetrations of DER (particularly PV distributed generation, DG) is rapidly becoming a reality in North America, which differentiates it from other foreseen smart distribution system incipient trends and planning needs.

Most commercial software tools provide models of conventional (synchronous) DG technologies and mainstream alternative DG technologies (wind and PV). These software tools enable the electric distribution utility to conduct conventional DG steady-state analysis, such as power flow studies and short circuit analysis. The types of studies that are deemed critical for planning and designing smart distribution systems include the following:

- Ability to conduct sequential (time-series) simulations, which is critical when analyzing variable DG and estimating impacts on distribution line equipment
- Support for enhanced models of LTCs and line voltage regulators to include new features provided by equipment and controller manufacturers, including selectable operation modes (cogeneration, bidirectional, and so on) and alternative feeder configurations (open delta)
- Advanced models of DES technologies, particularly of Battery Energy Storage Systems (BESS), which are starting to become a feasible alternative for variable DG integration, particularly through the introduction of the Community Energy Storage (CES) concept
- Modeling of less common DG technologies, such as microturbines and fuel cells.

Planning tools also need to address the dynamic/transient analysis of DER technologies.

Advanced Distribution Automation and Reclosing

Planning tools must be able to accurately and flexibly model automation schemes for complex control schemes that are being implemented on the distribution system. For instance, accurately modeling a distribution automation (DA) scheme involving more than two feeders (in a flexible manner, without time-consuming customization and programming) would be beyond the capabilities of existing commercially available tools. Here, accurately modeling implies taking into account equipment and feeder ratings, customizing switching times, and keeping track of reliability indices, including MAIFI and MAIFI_E.

For volt/VAR control and optimization, most of the tools provide solutions for identifying the optimal location of capacitor banks. But very few have specific modeling and simulation capabilities for handling the complex logic associated

with advanced volt/VAR optimization schemes, such as DMS model-driven, multi-objective VVO.

Sequential Simulation and Batch Processes

Planning tools should include a convenient mechanism for performing sequential (time-series) simulation, which is critical for estimating dynamic impacts of variable DG over a period of several minutes or evaluating the impact of advanced control systems (for example, VVO) over an extended period of time (for example, one year)—or accurately estimating system losses.

Advanced Distribution Reliability Modeling and Analysis

Planning tools should be able to estimate expected values of distribution reliability indices. But few programs offer the ability to calibrate the reliability parameters to match the actual field results. In some cases, this function performs well with small systems, but has difficulties with large systems. Therefore, this is an area that needs further improvement. Automated calibration is a desirable feature that would allow planners to conduct simulations in a faster and simpler manner, and would also increase the adoption of this type of analysis. This would also facilitate the implementation of integrated distribution planning (joint capacity and reliability planning), which is a very complex task using existing software tools.

Another limitation that has been observed is the ability to model the reliability of individual components, which allows studying the impact of individual deteriorated or aged components. Some of the software tools model reliability using generalized parameters; for example, all distribution lines on a feeder or all switches are assumed to have similar, generic failure rates and repair times. But this approach can produce inaccurate results, and it is usually preferable to assign parameters directly to each component. With this approach, the program should provide the capability to easily select and assign reliability parameters to a group of similar components.

Another related area that requires further development is the ability to calculate MAIFI and MAIFI_E. This is especially important when advanced DA and reclosing schemes are used. Few software tools are able to perform Monte Carlo analysis or reliability optimization to determine the best locations for protective and switching devices to improve reliability. These are areas that may become more important in the future, as utilities look into risk-based analysis and planning.

Finally, another area that is expected to grow in importance alongside the high penetration of combined DG/DES is intentional islanding and microgrid operation. Further, R&D work is required to develop capabilities to model and analyze the impact of islanding and microgrid operation on distribution system reliability and performance.

Interfacing with Utility Information Systems

Most developers offer some ability to interface with utility enterprise information systems, particularly SCADA and AMI. But it is difficult to objectively assess such claims. This is a desirable capability not only from a planning point of view but also from an operations perspective, since it would allow system operators to conduct off-line “what if” simulations, which is a feature offered by some DMS developers.

Interfacing with utility information systems requires the implementation of internal utility procedures for gathering and processing raw data, which is something that general utilities are still discussing or working on (for example, how frequent smart meters should be queried, how these data should be stored and processed, and so on).

Advanced Load Forecasting

Load forecasting has not been addressed in detail by the software tools for engineering, planning, and design that were reviewed in this project. A few tools are able to use the outputs of specialized spatial load forecasting programs and evaluate the effect of load growth on distribution system components. Nevertheless, no intrinsic spatial or time-series load forecasting capability was identified in any of the software tools that were evaluated.

In general, load growth in many areas has been minimal due, in part, to the global economic turndown. But load forecasting is expected to gain renewed interest, especially in how DER, DR, and PEVs will affect utility infrastructure. One issue of concern is the growing interest in establishments that have near-zero net energy consumption due to the use of consumer-owned distributed generation. But the electric utility must plan on providing sufficient capacity to meet the peak load of the establishment if local customer-owned generation is not available.

Another topic of rising interest is reactive load forecasting. This is needed to ensure that the power grid and the distribution system are able to satisfy reactive power requirements (in addition to real energy requirements) under all loading conditions.

PEV Modeling and Analysis

Another incipient and growing need is the ability to conduct comprehensive modeling and analysis for the integration and impact evaluation of plug-in electric vehicles (PEVs) in distribution systems. Of those evaluated for this report, one engineering software vendor claims to have specific models and simulation features to address this subject.

It is possible to conduct this type of analysis using several of the engineering analysis tools, because PEV charging patterns may be modeled by using

conventional loads with customized load profiles. This can be accomplished using sequential simulations or a script language. But since this alternative approach to PEV modeling and analysis may be time consuming and require advanced programming skills, the preferred and recommended approach is to add specific features to tools to address PEVs. It is especially important to be able to model PEVs in conjunction with other smart distribution technologies, specifically with DG and DES, since interaction among them is expected.

Joint Modeling of Transmission and Distribution Systems

There is increasing interest from utilities in jointly modeling and analyzing distribution and part of transmission and subtransmission systems. Several of the engineering analysis tools reviewed in this project offer this capability; others require purchasing additional modules for detailed modeling of distribution substations. It should be possible to import transmission and subtransmission models from databases of standard transmission software. Furthermore, analytical tools for electric distribution systems have been designed to handle circuits that are primarily radial in nature or “weakly meshed.” To properly handle transmission and subtransmission networks, the engineering tools must be able to work correctly for networked (heavily meshed) circuits as well as circuits that are primarily radial in nature.

Power Quality Modeling and Analysis

Utilities are increasingly interested in assessing how the increased high penetrations of DC/AC inverters used for DG and PEV integration will affect total harmonic distortion (THD) levels in the distribution system. Moreover, there are growing concerns about voltage fluctuations due to variable DG. To address these concerns, several engineering software tools offer harmonic analysis capabilities and some of them offer flicker-level evaluation.

Advanced System Component Modeling

New components such as static VAR compensators (SVCs), distribution STATCOMs, energy storage devices, “smart” AC inverters, and other devices with advanced controllers are being deployed in greater numbers at the distribution level. These new devices can be fairly complex and provide enhanced abilities for enhanced steady-state and dynamic control to improve efficiency, reliability, and power quality. It is expected that they will become even more commonplace as a means for integrating variable DG and PEVs and increasing the reliability, power quality, and efficiency of distribution systems. But few tools offer specific models of these technologies.

APPENDIX A

More on Road Map Methodology Approaches

This appendix provides pointers to different frameworks that can inform the preparation of the smart grid road map and a brief description of their approaches. Examples include the work of Sandia National Laboratory (SNL), the Electric Power Research Institute (EPRI), and the International Energy Agency (IEA).

Sandia National Laboratory

Since 1949, SNL has developed science-based technologies that support national security missions and include strong portfolios in energy efficiency and renewable energy. SNL develops technologies to sustain, modernize, and protect nuclear arsenals; prevent the spread of weapons of mass destruction; defend against terrorism; protect national infrastructure; ensure stable energy and water supplies; and provide new capabilities to armed forces. Sandia's strategic mission areas include nuclear weapons; energy, climate, and infrastructure security (ECIS); nonproliferation, defense systems, and assessments; and homeland security and defense. SNL is operated and managed by Sandia Corporation, a wholly owned subsidiary of Lockheed Martin Corporation. Sandia Corporation operates SNL as a contractor for the U.S. Department of Energy's (DoE's) National Nuclear Security Administration (NNSA) and supports numerous federal, state, and local government agencies, companies, and organizations (SANDIA website).

In 1997, Marie L. Garcia and Olin H. Bray from the SNL Strategic Business Development Department published the *Fundamentals of Technology Road Mapping*. It includes three phases:

- *Phase 1*. Preliminary activities consisting of three elements:
 - Satisfying essential conditions (for example, confirm the need for a road map)
 - Providing leadership/sponsorship
 - Defining the scope and boundaries for the technology road map

- *Phase 2. Development of the technology road map:*
 - Identifying the focus of the road map
 - Identifying critical system requirements and targets
 - Specifying major technology areas
 - Specifying drivers and targets
 - Identifying alternatives
 - Recommending technology alternatives
 - Creating a road map report
- *Phase 3. Follow-up activities:*
 - Critique and validation of road map
 - Developing an implementation plan
 - Review and update.

Electric Power Research Institute

EPRI is an independent nonprofit organization involved in research and development (R&D) in the electric power industry. The EPRI members fund collaborative R&D programs. The EPRI membership includes industry representatives from the United States as well as international entities.

In 2012, the EPRI published its methodology for the development of smart grid road maps. The approach consists of five key steps (EPRI 2012), as described in figure A.1.

- *Defining the vision.* This is a summary of what the utility/ISO intends to accomplish and why. This step also includes a mission statement that provides “how the vision statement will be accomplished.” The process of defining a vision statement begins with evaluating the essential business objectives and drivers that can be addressed by technology investments. Examples of objectives include increasing grid reliability and/or efficiency, ensuring cyber security, reducing costs, and so on.
- *Identifying the requirements.* One of the key elements of the EPRI approach is the use of cases based on an IntelliGrid approach to identify and define the requirements. It includes the needs and interactions of various actors (persons, applications, processes, and so on). It also includes logical interfaces with the relevant attributes such as timing, accuracy, volume, and so on.

Figure A.1 EPRI Smart Grid Road Map Process



Source: World Bank compilation from EPRI (2012).

- *Assessing and selecting the technology.* The EPRI has deployed a number of technology assessment methods that involve ranking a technology by impact and effort. The process has a goal to select technology candidates for road map implementation. The SG road map is responsible for selecting the top candidates based on their rank. A gap analysis follows to identify the gaps between the current and desirable technology state.
- *Planning.* An important element of the EPRI planning process is the establishment of fishbone diagrams that show the current situation as the “tail” and the future objective as the “head” of the fish. The steps to be taken are the “scales” of the fish (figure A.1).
- *Implementing the road map.* This includes the delivery of a report document, distribution to stakeholders, and project implementation and governance.

International Energy Agency

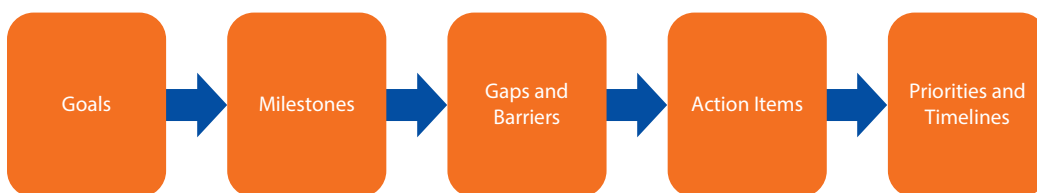
The IEA is a Paris-based intergovernmental organization established in the framework of the Organisation for Economic Co-operation and Development (OECD) in 1974. It is an autonomous organization that works to ensure reliable, affordable, and clean energy for its 28 member countries and beyond. The IEA's four main areas of focus are energy security, economic development, environmental awareness, and engagement worldwide.

The IEA has developed a methodology for its members for the development of a road map and used this methodology to develop a smart grid technology road map for IEA member countries, as shown in figure A.2 (IEA 2011).

The IEA road map methodology includes the following elements:

- *Goals.* A clear and concise set of targets that, if achieved, will result in the desired outcome
- *Milestones.* The interim performance targets for achieving the goals, pegged to specific dates
- *Gaps and barriers.* A list of any potential gaps in knowledge, technology limitations, market structural barriers, regulatory limitations, public acceptance, or other barriers to achieving the goals and milestones

Figure A.2 IEA Smart Grid Road Map Process



Source: World Bank compilation from IEA (2011).

- *Action items.* Actions that can be taken to overcome any gaps or barriers that stand in the way of achieving the goals
- *Priorities and timelines.* A list of the most important actions that need to be taken to achieve the goals and the time frames, taking into account interconnections among those actions and stakeholder roles and relationships.

The IEA road map process includes the following phases:

- **Planning and preparation**
 - Establishing a Steering Committee
 - Determining the scope, boundaries, and implementation approach
 - Developing energy, environmental, and economic data to establish a baseline
- **Vision**
 - Identifying long-term goals and objectives
 - Analyzing future scenarios for energy and environment
- **Road map development**
 - Identifying and prioritizing needed technologies, policies, and timelines
 - Developing a road map document, launch strategy, and tracking system
 - Conducting review cycles
 - Assessing potential contribution of technologies to future goals
- **Road map implementation and revision**
 - Reassessing priorities and timelines as progress is made and new trends emerge
 - Tracking changes as the road map is implemented.

Additional Examples of Road Maps from Electric Utilities

This section briefly describes the smart grid road maps of some power utilities and provides pointers to additional information.

California Utilities: Pacific Gas and Electric

California state policies of 2009 resulted in smart grid deployment plans for each of the several California utilities. Pacific Gas and Electric (PG&E), in collaboration with the EPRI, Southern California Edison Company, and San Diego Gas and Electric Company (SDG&E), developed a California road map for the state's smart grid of the future (EPRI 2011). PG&E has developed its own smart grid deployment plan, which was developed according to the state's future goals (PG&E 2011).

Vision

PG&E's vision is to "provide customers safe, reliable, secure, cost-effective, sustainable and flexible energy services through integration of advanced communications and control technologies to transform the operations of PG&E's electric network, from generation to the customer's premise."

Drivers

Drivers of the PG&E smart grid program support California's energy and environmental policies:

- *Safety, reliability, and security*
- *Customer empowerment.* PG&E wants customers to be able to control their consumption through demand response (DR) programs and advanced metering infrastructure (AMI) technologies
- *Efficient and flourishing electricity markets.* PG&E envisions open and robust energy markets through a "standards-based platform" to enable the sale of

smart grid products and services into energy markets on an “equal footing” with traditional generation sources

- *Environmental sustainability* through integrating distributed renewable energy technologies and increasing grid efficiency
- *Consumer and technological advancement.* PG&E envisions its smart grid deployment plan as a continuous journey or a repeating learning process that includes researching, developing, evaluating, and demonstrating new technologies until such technologies become obsolete and replaced by newer ones.

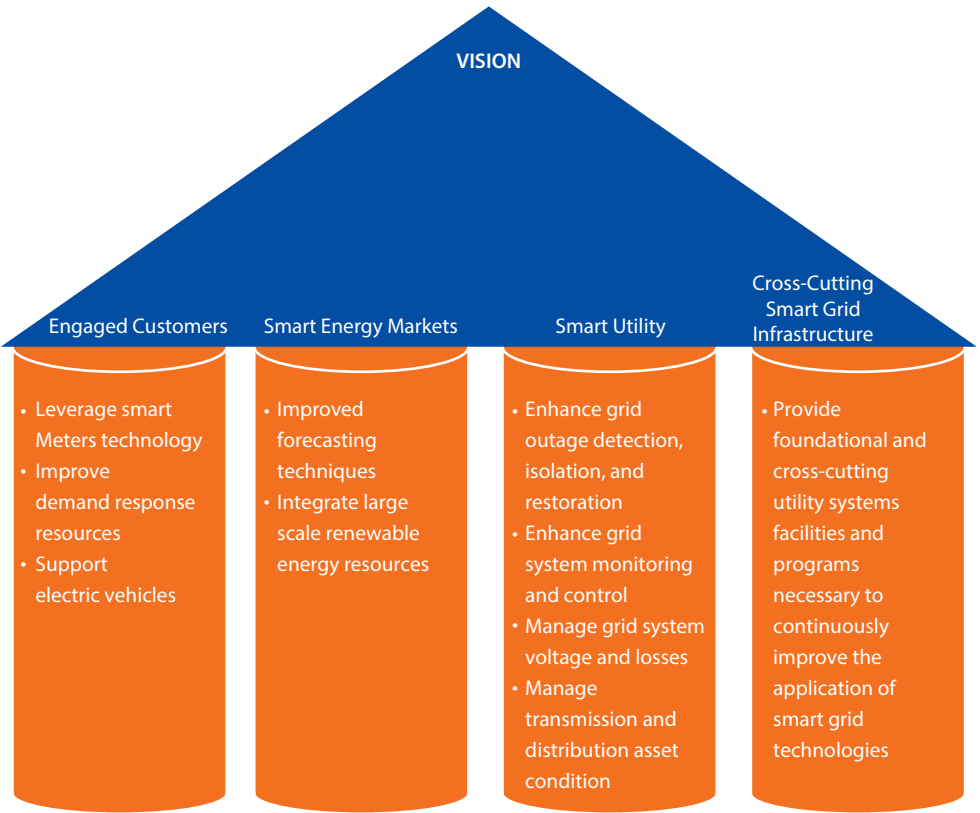
Pillars of Action

PG&E’s smart grid deployment plan adopts 10 high-priority, strategic smart grid objectives in four program areas to guide PG&E’s smart grid investments and initiatives over the next decade (see figure B.1).

Time Frame, Benefits, and Costs

The estimated costs of the smart grid projects and initiatives is expected to be approximately US\$800 million—US\$1.25 billion in capital and US\$500 million—US\$700 million in cumulative operating expense over the next 20 years.

Figure B.1 Pacific Gas and Electric’s Vision and Pillars of Action



Source: World Bank compilation from PG&E 2011.

The benefits far exceed the costs and are estimated to be US\$600 million to US\$1.4 billion in lower procurement costs, US\$200 million to US\$400 million in avoided capital costs, and US\$100 million to US\$200 million in avoided operating and maintenance costs over the next 20 years. Estimated nonfinancial benefits include 10–20 percent improvement in system reliability and 1.4–2.1 million metric tons of avoided carbon dioxide (CO₂) emissions.

California Utility: San Diego Gas and Electric

Vision and Drivers

San Diego Gas and Electric (SDG&E) is another California utility that came with its own smart grid deployment plan (SDG&E 2011) in accordance with California's future energy goals. SDG&E's vision is to "create the foundation for an innovative, connected and sustainable energy future, in collaboration with key stakeholders." SDG&E's vision is being driven by the following facts:

- Solar distributed generation (DG) is growing fast within SDG&E in an effort to help customers reduce their carbon footprint.
- Plug-in electric vehicles (PEVs) are currently being introduced into the San Diego market in an effort to help individual customers reduce fuel consumption and associated emissions and costs.
- There are new technologies that allow customers to manage their energy consumption and associated environmental impact.

Pillars of Action

After discussions with stakeholders and customers, SDG&E identified three areas of interest: customer behavior/education, demand response, and rate design. Its pillars of action were based on these areas (see table B.1).

SDG&E's deployment plan includes implementation of a set of actions before 2015, while completion is expected to happen in 2020. More information can be found in SDG&E (2011).

U.S. National Institute of Standards and Technology

- The NIST engaged the EPRI to prepare a smart grid standards road map.
- The Federal Energy Regulatory Commission (FERC) identified four smart grid functional priorities that include:
 - Wide area situational awareness
 - Demand response
 - Electricity storage
 - Electric vehicles
- Two additional categories of applications:
 - Distribution grid management initiatives
 - Advanced metering infrastructure

Table B.1 SDG&E’s Deployment Plan: Pillars of Action

<i>Key Themes of the SDG&E Smart Grid Deployment Plan</i>
<ul style="list-style-type: none">• <i>Educate customers on energy opportunities and choices.</i> Customer and stakeholder education around smart grid issues is important for the success of the program. This can happen through utilizing peer-to-peer education.• <i>Facilitate energy efficiency and demand response.</i> This can happen through utilizing AMI technologies and launching DR programs. Customers need to be offered cost-based and time-differentiated rates to participate in peak demand reduction schemes and achieve cost reductions.• <i>Enable plug-in electric vehicles (PEVs).</i> Community planning is important to facilitate the construction of charging stations. Also, time-differentiated charge/discharge rates can be an effective way to encourage effective peak reduction during peak hours.• <i>Enable and integrate energy storage</i> as a means to reduce the impact of solar intermittency on the distribution network.• <i>Expand collaboration</i> among SDG&E and its vendors, suppliers, business partners, community organizations, key stakeholders, and academia to enhance exchange of knowledge and enable success of the smart grid plan.• <i>Support workforce readiness.</i> People with new talents and skills are needed to design, implement, manage, and operate the new smart grid technologies. SDG&E will work with the industry and academia to create a new local “reservoir” of talent.• <i>Integrate distributed energy resource (DER)</i> with an emphasis on distributed combined heat and power (CHP) plants.• <i>Expand technology development.</i> In order for the smart grid to succeed, new technologies must be introduced in the market and older technologies must be modernized. Investments should target the development of technologies that interface well with the smart grid.

Source: World Bank compilation from SDG&E 2011.

- Two cross-functional areas:
 - Cybersecurity
 - Network communications

Canada–Toronto Hydro-Electric System Ltd

Vision Drivers and Pillars of Action

Toronto Hydro-Electric System Limited (THESL) plans to implement a smart grid in accordance with Ontario’s Green Energy Act, which mandates the implementation of a smart grid with the following characteristics (THESL 2009):

- Enables the increased use of distributed renewable energy sources
- Expands opportunities to provide DR programs driven by the time-varying price of electricity
- Accommodates the use of new technologies that promote energy efficiency and system control applications
- Supports other objectives that may be prescribed by regulations

- The Ontario Smart Grid Forum that promotes the industry's vision for the city's grid of the future
- The City of Toronto's "Change Is in the Air: Clean Air, Climate Change, and Sustainable Energy Action Plan" that has a goal to make Toronto the renewable energy capital of Canada.

THESL's vision includes three main targets that rest on sets of pillars of identified action:

1. Climate protection and sustainable energy
 - Accommodate distributed renewable energy and energy storage
 - Support reliable connection of microgrids, community energy, and virtual power plants
 - Enable electrified transportation infrastructure
 - Reduce THESL's carbon footprint
2. Energy security
 - Manage risks associated with aging infrastructure
 - Provide grid control mechanisms
 - Monitor power quality levels and losses
 - Improve efficiency and effectiveness of utility operation
 - Incorporate physical and cyber security measures
3. Customer satisfaction
 - Use smart grid technology to enable customers informatively control their electricity consumption and carbon footprint.

THESL's road map implementation has a time horizon of 25 years and is expected to be completed in three phases as shown in table B.2.

China

The State Grid Corporation of China (SGCC) is planning to build a smart grid with ultra-high-voltage (UHV) lines and subordinate grids coordinated at various voltage levels. As shown in figure B.2 smart grid is planned to be completed by 2020 in three phases (SGCC 2010):

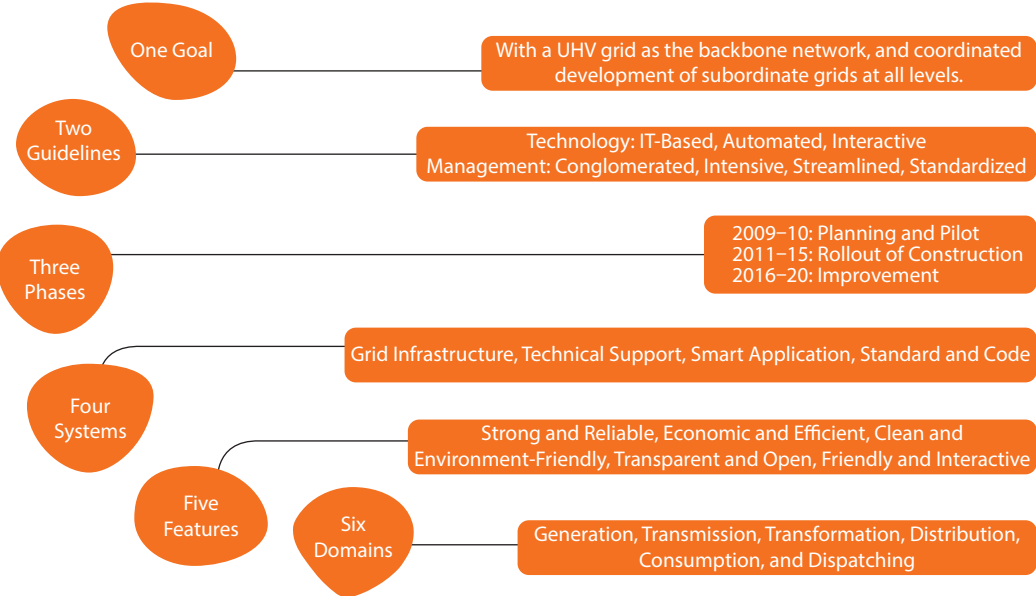
- *Phase 1 (planning and pilot)* is already complete and includes years 2009 and 2010. It was a planning and trial phase where the grid specifications were set and a number of pilot programs took place.
- *Phase 2 (roll out construction)* is currently happening and includes the period 2011–15. Main characteristics of this phase are as follows:
 - Construction of the UHV grid
 - Construction of rural/urban distribution networks
 - Establishment of preliminary smart grid operation and control systems
 - Extensive use of key technologies

Table B.2 THESL’s Smart Grid Deployment Plan Phases and Pillars of Action

Phase 1 (0–3 Years)	Phase 2 (3–10 Years)	Phase 3 (10–25 Years)
<ul style="list-style-type: none">• AMI integration• Early DR programs• Cyber security systems• Early DA systems integration (for example, power line metering and integrated outage management)• Early DG programs	<ul style="list-style-type: none">• Substantial growth of DG installations• Integration of distributed energy storage systems• Early implementation of V2G• DA enhancement (for example, Volt/VAR control, phase balancing systems, power quality management systems)• Use of smart appliances at homes will grow	<ul style="list-style-type: none">• Creations of microgrids• Fully electrified transportation• Decentralization of energy generation will be completed• Fault anticipation

Source: World Bank compilation from THESL 2009.
Note: DA = distributed automation; DG = distributed generation; DR = demand response; V2G = vehicle to grid; AMI = Advanced Metering Infrastructure

Figure B.2 SGCC’s Main Smart Grid Characteristics



Source: Developing Strong and Smart Grid: The Best Practice of State Grid Corporation of China, SGCC, 2010.
Note: UHV = ultra-high voltage.

- *Phase 3 (lending and enhancing phase).* During this phase (2016–20), the grid construction will be completed. The progress will be evaluated regularly, and certain enhancements in the area of security and efficiency will take place.

Since 2009, the SGCC has started 228 demonstration projects in 21 categories across 26 provinces and municipalities. Types of projects include the following:

- Integration of clean energy/energy storage/microgrid technologies
- Superconducting transmission
- Smart substations
- Distribution automation
- Electricity quality monitoring
- Customized power service
- Power consumption information systems
- Smart communities/buildings
- EV charging and battery-switching facilities
- Smart street lamp monitoring systems
- Interactive service centers
- Smart demand management
- Fault management systems.

Thailand: Provisional Electricity Authority

Vision

The Thai Provisional Electricity Authority's goal is to:

- Increase energy efficiency and maintain the environment (smart energy)
- Improve quality of life (smart life)
- Provide intelligent and green community in the future.

Drivers

Drivers of the SG program include the following:

- Energy security and environmental awareness
- Customer's demand for informative decisions
- Society's demand for a safe and ecofriendly grid
- Provisional Electricity Authority officers' demand for a safe and pleasant working environment.

Time Plan and Pillars of Action

The plan will take place in three phases and is expected to be completed by 2026 (see table B.3).

Ireland

The Irish electricity industry has one power sector regulator for the country, the Commission for Energy Regulation (CER), and one main dominant electricity supplier and transmission owner and operator, the Electricity Supply Board (ESB), with more than 95 percent government ownership.

Ireland defines a smart grid as “an electricity network that can cost efficiently integrate the behavior and actions of all users connected to it—generators,

Table B.3 Provisional Electricity Authority's Smart Grid Deployment Plan Phases and Pillars of Action

<i>Planning and pilot project phase (2012–16)</i>	<i>Phase 2 (2017–21)</i>	<i>Phase 3 (10–25 years)</i>
Microgrids	Large expansion of planning and pilot projects started during phase 1	Decentralization of power generation
Integration of energy storage technologies		Customers can buy or sell electricity
AMI implementation to enable two-way communication among grid components and central operations		Virtual power plants creation
Integration of customer-owned distributed generation technologies with option to sell energy to the grid		Self-healing network
Enable options for informative usage of electricity by customers (DR programs)		Two-way power supply of electricity for EVs (V2G)
Use of smart appliances		Peak demand reduction through EVs usage
Incorporation of EVs and charging stations		
Electricity generation from waste		
Increase use of electric transportation like EVs, and electric bus and train systems		

Source: World Bank compilation from the Provisional Electricity Authority website.

Note: AMI = advanced metering infrastructure; DR = demand response; EV = electric vehicle; V2G = vehicle to grid

consumers and those that do both—in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety.”

Ireland has published three road maps that involve smart grid technologies—one for the smart grid, one for wind energy, and another for electrical vehicles.

The Irish smart grid objectives include the following:

- *Decarbonization of electricity* with annual savings of over 13 million tons of CO₂ by 2050. Eight million tons of this will be derived directly from the implementation of a smart grid. A further 5 million tons will come from the displacement of fossil fuels due to the electrification of transport and thermal loads, facilitated by the smart grid.
- *Increased electrification of thermal loads* in the residential and services sector. It is estimated that the annual demand in this sector will exceed 28,000 gigawatt-hours by 2050.
- *Electrification of transport*. Domestic transportation sector will be expected to demand close to 8,000 gigawatt-hours by 2050.
- *Renewable energy integration*. Overall annual electrical final energy demand will be in excess of 48,000 gigawatt-hours by 2050 with a corresponding peak demand of 9 gigawatts. Onshore wind generation will be able to supply up to 33,000 gigawatt-hours of the total demand.
- *Reduction of energy imports*. Greater integration of indigenous renewable energy sources will see a net reduction in energy imports in excess of 4.3 Mtoe¹ (equivalent to € 3.2 billion–€ 7.2 billion savings in direct fuel offsets by 2050).

- *Increased interconnection.* By 2025, Ireland aims at having 1.4 gigawatts of interconnection. Analysis indicated that a further 1.6 gigawatts of interconnection will be required by 2040.
- *Job creation.* It is estimated that more than 10,000 Irish jobs will be created by implementation of smart grid infrastructure and its associated technologies.

The main components of the Irish smart grid road map to achieve the stated decarbonization goals include the following:

- Peak and load shifting and demand-side management (DSM)
- Reduced line losses, infrastructure improvements, and volt/VAR management
- Integration of renewables
- Electrification of transport
- Electrification of heating, cooling, and hot water
- Electrification of industrial heating/cooling loads.

Furthermore, the smart grid road map for Ireland calls for the following actions within the next 10 years:

- Establishment of a test-bed facility, strengthening Ireland's position as a leader in smart grid technology research
- Development and deployment of training courses in smart grid systems and technologies
- Review of policies dealing with energy and CO₂ ratings of buildings to encourage electrification
- National rollout of smart meters with DSM and variable time-of-use tariffs
- Development of interoperability standards and secure communications and data protocols
- The continuation of the grid investment programs Grid-West and Grid 25
- Development of an overlay of secure, high-speed communications onto the electricity system.

France

In the publication "Road Map for Smart Grids and Electricity Systems Integrating Renewable Energy Sources," four main challenges are identified in the European context:

- Attain emissions reduction objectives for greenhouse gases (GHG) set for 2020 (20 percent reduction) and for 2050 (factor 4), notably via energy-efficiency schemes
- Compliance with European objectives for the integration of renewable energy
- Maintaining the quality and security of supply in the electricity system

- Consideration of social issues related to electricity supply.

The road map considers two time frames—up to 2020 and up to 2050:

- The time frame up to 2020 is focused on attaining European objectives (20/20/20), while maintaining high-quality supply and system security.
- The 2050 time frame allows for contrasting representations of future electricity networks and systems, based on the unfolding of trends identified in the 2020 time frame, subject to different regulatory options envisioned for grids and electricity systems.

The road map identifies three key drivers that, in the long term, will play a determining role in the form and nature of smart grids and electrical systems:

- The degree of intelligence in the electricity system and grids, and the range of products and services associated with this capacity
- The degree and type of decentralization in the system and grids
- Regulatory choices, business models, and the role of players affecting smart grids and electrical systems.

Variation in the parameters of the different key drivers (intelligence, decentralization, regulation) leads to four contrasting visions of the electricity system and networks. Two visions for the 2020 timeframe and two visions for the 2050 timeframe are as follows:

- Vision 2020—1: Demand flexibility and storage facilities coupled to large-scale variable generating capacity
- Vision 2020—2: Demand flexibility and management of dispersed storage
- Vision 2050—1: Demand flexibility, storage, and distributed energy resource (DER) in a centralized grid architecture
- Vision 2050—2: Demand response and DER in smart clusters.

Note

1. Million tons of oil equivalent.

Some Guidelines on the Cost-Benefit Analysis of Smart Grid Applications

This sections list some references to useful documents that describe guidelines on the CBA of smart grid applications.

<i>Guidelines</i>	<i>Brief description</i>
U.S. Smart Grid Development and Global Smart Grid Coordination (Eric Lightner 2012)	This presentation by Eric Lightner, director of the Smart Grid Task Force to the Board on Global Science and Technology, describes the vision, characteristics, challenges, and key activities of the smart grid of the future in the United States. Additionally, the presentation provides details regarding a metric reporting and analysis process to quantify the monetary benefits related to smart grid functions.
Guidelines for Conducting a Cost-Benefit Analysis of Smart Grid Projects—European Union (CBA Methodology) (Giordano and others 2012)	This report by European Union's Joint Research Center, Institute for Energy and Transport, provides step-by-step guidance for conducting CBA of smart grid projects. This framework is based on a similar methodological approach developed by the Electric Power Research Institute (EPRI) in the United States. CBA includes three main tasks—the definition of boundary conditions and implementation choices, identification of costs and benefits, and sensitivity of CBA results to variations in key parameters.
Building a Smart Grid Business Case (NETL 2009)	This guidance brief by the National Energy Technology Laboratory (NETL), United States, helps in developing regional smart grid road maps. Assessing the gap between the current state and desired future state of the grid, business cases, and implementation plans can be analyzed and integrated into a road map. Business cases, thus devised, help in disaggregating the costs incurred and benefits accrued by diverse smart grid stakeholders such as consumers, utilities, and society. This document provides guidance for gap analysis, formulation of business cases, and road mapping.

Glossary

<i>Adaptive relay</i>	A protective relay whose internal settings change automatically as the portion of the power grid associated with the relay changes.
<i>Advanced metering infrastructure</i>	An integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers.
<i>Anti-islanding</i>	A protective measure to ensure that distributed generating units automatically disconnect from a portion of the power grid that has become separated from the main power grid.
<i>As-built model</i>	A software model representing the normal or nominal status of all electric distribution components.
<i>As-operated model</i>	A software model representing the current operating status of all electric distribution components.
<i>Asset optimization</i>	The practice of achieving the best possible performance of any distribution system component.
<i>Automatic meter reading</i>	Technology for automatically collecting consumption, diagnostic, and status data from electric meters and transferring that data to a central database for billing, troubleshooting, and analyzing.
<i>Bidirectional voltage regulator</i>	A controller that adjusts its voltage in accordance with the magnitude and direction of load flow.
<i>Big data</i>	Large and complex data sets containing information from smart meters and SCADA systems that are analyzed to determine key performance metrics (see also “data mining”).
<i>Capacitor bank controller</i>	An autonomous or remotely controlled device that manages capacitor bank switching.
<i>Community energy storage</i>	Small remote-controlled batteries connected to the distribution secondary (LV) circuit.
<i>Computer-assisted decision making</i>	A process that uses the results of computer system analysis as an aid in the operation and overall management of the distribution system.

<i>Conservation voltage reduction</i>	Intentional reduction of voltage within established limits, whenever such actions are possible to achieve demand reduction and energy savings.
<i>Customer participation</i>	The process of enabling customers to make voluntary changes in their electricity consumption patterns to reduce peak demand and conserve energy.
<i>Data concentrator</i>	A device that collects information from a variety of independent sources (sensors, meters, and so on) and then transmits this information over a single communication channel.
<i>Data mining</i>	The practice of automatically searching large stores of data to discover patterns and trends that go beyond simple analysis.
<i>Demand response</i>	Processes in which end-use customers reduce their use of electricity in response to power grid needs, economic signals from a competitive wholesale market, or special retail rates.
<i>Distributed energy resource</i>	Small-scale generators, energy storage devices, and controllable loads that are connected to the MV or LV portion of the electric distribution system.
<i>Distributed generation</i>	Small-scale generating units that are connected to the MV or LV portion of the electric distribution.
<i>Distribution management system</i>	A computer system and suite of software applications designed to assist distribution system operators in improving the overall performance of the electric distribution system.
<i>Drive-by metering systems</i>	Process by which electric meters can be read from the street by a passing vehicle.
<i>Electric vehicles</i>	An automobile, van, or truck whose drive train is powered primarily by electricity.
<i>Electrically operable switch</i>	A high-voltage switch that is equipped with a solenoid or motor-operating mechanism that can be opened or closed via a signal from an electric circuit.
<i>Energy storage</i>	A device that is able to store energy and release the energy on demand.
<i>Energy theft detection</i>	Processes of determining that electric energy is flowing to a consumer without being recorded by the meter.
<i>Fast demand response</i>	Automated process of controlling end-use consumer-owned devices with very low latency (less than 5 minutes) to mitigate the adverse consequences of a power system emergency.
<i>Fault anticipation</i>	The process of detecting an incipient power system short circuit so that corrective action may take place before a full-blown fault occurs.

<i>Fault location</i>	Analytical techniques for determining the approximate location of a short circuit.
<i>Fault location isolation and service restoration</i>	An automatic or semi-automatic switching system for rapidly restoring power automatically to as many end-use customers as possible.
<i>Faulted circuit indicator</i>	A sensor that generates a signal when line current flowing through the device exceeds an established threshold.
<i>Feed-in tariff</i>	A method by which end-use customers are compensated financially for supplying energy to the power grid from customer-owned distributed generation.
<i>Field communication network</i>	An electric distribution telecommunication facility that supports multiple applications such as advanced metering infrastructure (AMI), distribution automation (DA), distributed generation (DG), and workforce automation.
<i>Fully automated</i>	A system that operates with no human intervention.
<i>Grid modernization</i>	The use of computer and communication technologies to improve the overall performance of the electric grid.
<i>Information technology</i>	The study or use of systems (especially computers and telecommunications) for storing, retrieving, and sending information.
<i>In-home display</i>	A home energy monitor that provides prompt, convenient feedback on electrical or other energy use.
<i>Intelligent electronic device</i>	A term used in the electric power industry to describe microprocessor-based controllers of power system equipment, such as circuit breakers, transformers, and capacitor banks.
<i>Islanding</i>	An operating mode in which a portion of the electric system becomes disconnected from the main power grid but remains energized and continues to supply electricity to end-use customers.
<i>Load balancing</i>	The process of transferring electrical load from a heavily loaded facility to a lightly loaded facility to achieve a more even split.
<i>Managed charging of electric vehicles</i>	The process of controlling the charging rate of an electric vehicle to minimize loading on the power grid.
<i>Mesh radio</i>	A wireless method of communication in which information is transmitted through a network of transmitters/receivers en route to its final destination.
<i>Microgrid</i>	A small portion of the electric system that serves the electricity needs of the local community (the microgrid may operate while connected to the main grid as well as from a separate island that is disconnected from the main grid).

<i>Microprocessor</i>	A small computer that enables intelligent electronic devices (IEDs) to operate autonomously or via remote control to achieve a flexible set of business objectives.
<i>Momentary average interruption frequency index</i>	A metric that is used to indicate the number of power interruptions lasting less than five minutes (and less than one minute in some jurisdictions).
<i>On-line power flow</i>	A computer program that uses a distribution system model for computing the electrical conditions at any point on the electric distribution feeder.
<i>Optimal network reconfiguration</i>	A computer program that determine switching actions that may be performed in a selected portion of the distribution system to accomplish specified business objectives (reduce electric losses, balance load, and so on).
<i>Outage management system</i>	A computer system for managing the electric utility's response to power outages; this system typically processes calls from customers, manages field crew activities, and tracks reliability statistics.
<i>Phasor measurement unit</i>	A device that measures the electrical waves on an electricity grid, using a common time source for synchronization.
<i>Remote terminal unit</i>	A SCADA system component that acquires data from a variety of sources (sensors, meters, and hardwired inputs), converts data to engineering units, stores this information, and transmits the information automatically or upon request to a central location via available telecommunication facilities.
<i>Renewable energy</i>	Energy that is generated from natural processes that are continuously replenished; sources include sunlight, geothermal heat, wind, tides, water, and various forms of biomass.
<i>Renewable generation</i>	Electricity generators that are powered by renewable energy sources.
<i>Resilience</i>	The ability of a facility to withstand stress and catastrophe; for electrical distribution systems, this generally refers to the ability of the power infrastructure (lines, poles, and so on) to prevent total failure due to severe storms and other emergencies.
<i>Reverse power flow</i>	An electrical condition in which the direction of power flow is opposite to what is normally expected; in today's context this refers to the reversal of power flow due to the high output of distributed generating facilities.
<i>Rule-based system</i>	A solution technique in which decisions are made based on a fixed set of simple logical comparisons (if-then-else).

<i>Self-healing</i>	A process by which all or part of the electrical system is restored automatically (without human intervention) following a power outage or service interruption.
<i>Semi-automated</i>	An approach that uses a combination of fully automated processes (that do not involve human intervention) and manual processes to achieve a desired result.
<i>Sensor</i>	A device that measures an electrical quantity (voltage, current, and so on) and produces a computer-readable signal that represents the original measurement value.
<i>Smart AC inverter</i>	A device that converts the DC power produced by distributed generators and energy storage devices to the AC power that flows on the power lines; “smart” AC inverters have the ability to dynamically change the way this conversion is performed based on distribution system operating conditions.
<i>Smart grid</i>	A conceptual vision of an electric system whose realization requires the use of conventional and advanced computer and communication technology.
<i>Smart meter</i>	A device for measuring end-users’ electricity consumption and other end-use information and transmitting this information on demand to a central location.
<i>Solar photovoltaic power</i>	A process for generating electricity directly from sunlight via an electronic process that occurs naturally in certain types of material, called semiconductors.
<i>Stand-alone device</i>	A device that is able to operate autonomously using only “local” measurements.
<i>Static VAR compensator</i>	A set of electrical devices for providing fast-acting reactive power on high-voltage electricity transmission and distribution networks.
<i>Supervised operation</i>	A process that requires human oversight and approval of all computer-based control actions.
<i>Supervisory control and data acquisition</i>	A system for continuously monitoring and initiating remote control actions for field devices over telecommunication facilities.
<i>System Average Interruption Duration Index</i>	A metric that indicates the total time in a year that the average end-user is without power.
<i>System Average Interruption Frequency Index</i>	A metric for indicating how many times the average end-user is without power in a given year.
<i>Time-of-use rates</i>	A tariff system in which the unit cost of electricity to the end-user varies with the time of day; for example, the unit cost is higher during peak load periods.

<i>Two-way communication network</i>	A telecommunication facility that is able to transmit information to and receive information from a field device.
<i>Vehicle-to-home capabilities</i>	A system that allows an end-user to deliver energy to the home from an electric vehicle car battery.
<i>Volt/VAR optimization</i>	A process of controlling voltage and reactive power flow on the electric distribution system to improve overall system performance; the process allows a utility to reduce electrical losses, eliminate voltage profile problems, and reduce electrical demand.
<i>Wi-Fi</i>	A local area wireless technology that allows an electronic device to exchange data or connect to the Internet over short distances (approximately 66 feet indoors).
<i>Wind power</i>	Conversion of wind energy into electricity.
<i>Zero net energy</i>	A point at which the total amount of energy used by a particular site (for example, a building) on an annual basis is roughly equal to the amount of renewable energy created on the site.

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Practical Guidance for Defining a Smart Grid Modernization Strategy: The Case of Distribution guides stakeholders on how utilities can define their own smart grid vision, identify priorities, and structure investment plans. While most of these strategic aspects apply to any area of the electricity grid, the book focuses on distribution. The guidance includes key building blocks for modernizing the distribution grid and provides examples of grid modernization projects. This revised edition also includes key communication system requirements to support a well-functioning grid.

The concept of the smart grid is relevant to all grids. What varies are the magnitude and type of the incremental steps toward modernization for achieving a specific smart grid vision. A utility that is at a relatively low level of grid modernization may leapfrog one or more levels of modernization to achieve some of the benefits of the highest levels of grid modernization.

Smart grids impact electric distribution systems significantly. In developing countries, modernizing the distribution grid promises to benefit the operation of electric distribution utilities in many and various ways. These benefits include improved operational efficiency (such as reduced losses and lower energy consumption), reduced peak demand, improved service reliability, and ability to accommodate distributed generating resources without adversely impacting overall power quality.

Practical Guidance for Defining a Smart Grid Modernization Strategy concludes by describing funding and regulatory issues that may need to be taken into account when developing smart grid plans.

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