Miroslav M. Begovic *Editor*

Electrical Transmission Systems and Smart Grids

Selected Entries from the Encyclopedia of Sustainability Science and Technology

Springer

Electrical Transmission Systems and Smart Grids

This volume collects selected topical entries from the *Encyclopedia of Sustainability Science and Technology* (ESST). ESST addresses the grand challenges for science and engineering today. It provides unprecedented, peer-reviewed coverage of sustainability science and technology with contributions from nearly 1,000 of the world's leading scientists and engineers, who write on more than 600 separate topics in 38 sections. ESST establishes a foundation for the research, engineering, and economics supporting the many sustainability and policy evaluations being performed in institutions worldwide.

Miroslav M. Begovic
Editor

Electrical Transmission Systems and Smart Grids

Selected Entries from the Encyclopedia of Sustainability Science and Technology

Springer

Editor
Miroslav M. Begovic
School of Electrical and Computer Engineering
Georgia Institute of Technology
Atlanta, GA, USA

This book consists of selections from the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers, originally published by Springer Science +Business Media New York in 2012.

ISBN 978-1-4614-5829-6 ISBN 978-1-4614-5830-2 (eBook)
DOI 10.1007/978-1-4614-5830-2
Springer New York Heidelberg Dordrecht London

Library of Congress Control Number: 2012954271

Printed on acid-free paper

Springer is part of Springer Science+Business Media (www.springer.com)

Contents

Chapter 1
Electrical Transmission Systems and Smart Grids, Introduction

Miroslav M. Begovic

Transmission systems represent the backbone of the electric energy. They support transport of electric energy from large producers (power plants) to the load centers (residential areas, manufacturing facilities, business centers or a combination thereof). Those networks are probably among the largest human-made engineering systems – the transmission network in the United States covers over 300,000 km of lines and is served by 500 companies (electric utilities).

In contemporary power systems, the notion of net energy producers and net users is increasingly blurred as most economic generator capacities are of smaller size and can be (and often are) installed near users' locations – example of small photovoltaic generators or wind farms which can be installed on the roofs of residential homes or in their vicinity illustrates that alternative, popular for many reasons (little or no maintenance needed, decreasing cost of electricity generated by such small generators, many of which are based on various renewable energy sources, reduction of congestion which is the result of carrying large amounts of power across vast distances, reduction of transmission losses, regulatory and policy-driven economic incentives for small owners of generators, reduction of carbon footprint, and enhancement of sustainability of such solutions, etc.) The need for electric energy systems is not only to run the equipment in manufacturing facilities or appliances in residential homes, but also to interact in various ways with other supporting infrastructures (water, gas, transportation, information, etc.) Those infrastructures are interdependent on one another and their efficient and

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3

M.M. Begovic (✉)
School of Electrical and Computer Engineering, Georgia Institute of Technology,
777 Atlantic Dr. NW, Atlanta, GA 30332-0250, USA
e-mail: Miroslav@ece.gatech.edu

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*,
DOI 10.1007/978-1-4614-5830-2_1,

reliable operation requires a thorough understanding of those interdependencies and adequate planning and operational support (see Energy and Water Interdependence, and Their Implications for Urban Areas).

As electric energy travels across waveguides (conductors), it incurs losses due to dissipation of current across the resistances of imperfect conductors. High-voltage overhead conductors do not need insulation. The conductor material is nearly always made of an aluminum alloy, which typically forms several strands and often is reinforced with steel strands for mechanical strength. Copper was more popular conductor choice in the past, but substantially lower weight and cost of aluminum and its only marginally inferior electrical performance have been the reasons for the current dominance of aluminum-based conductors in the transmission networks. As large amounts of power being transferred across the lines may incur considerable losses in transmission, typically such bulk transfers are performed at higher voltages, which require smaller currents (losses in the conductors are proportional to the square of the current, which means that operating the transmission line at double the voltage incurs only about 25% of the losses produced while operating at lower voltage). It is the need for changing the operating voltage levels as a function of the energy throughput that has forced design transition from the original DC transmission (introduced by Thomas Edison) into AC, originally deployed by Nikola Tesla and George Westinghouse in the 1880s to transfer power from the power plant at Niagara Falls, and nowadays used almost everywhere. Today, the highest operating AC transmission voltages can be up to 500 kV and even 800 kV. Ironically, when need for high power transfers calls for operation at voltages higher than 800 kV, it is done via DC transmission and with use of the large HVDC converter stations. The reason is inductances of the large overhead transmission lines, which at the highest voltages ultimately choke the efficient transmission of electric energy.

Transmission voltages are usually considered to be 110 kV and above. Lower voltages such as 66 kV and 33 kV are commonly called sub-transmission voltages. Voltages less than 33 kV are mostly used for distribution. Design of distribution networks is driven by their traditional role as infrastructure for disseminating bulk electric energy to a large number of customers. Such fragmentation of delivery requires distribution networks to operate somewhat analogous to capillaries in a cardiovascular system, at smaller capacities (and lower voltages) and covering large areas of sparsely populated customers (in rural areas) or densely populated smaller areas (in modern urban settings where increasingly large part of the world population now resides). Traditional design is evolving of radial distribution network, consisting of feeders supplied from the substations which interconnect them to the bulk power transmission networks. Such simple configurations were enabled by unidirectional flows of energy and simple distribution hardware which was supporting it. Transformation of distribution system into the site of both consumption and (distributed) generation of electric energy, as well as increasing need for enhanced interconnectivity at the distribution level, is imposing need for different designs. Part of the contemporary distribution networks are likely to experience a transition to microgrids (more meshed and better controlled distribution networks which can be used flexibly as reconfigurable autonomous, or grid-connected infrastructure for distribution of electric energy).

The structure and function of electric substations is also changing rapidly. Substations represent a vital part of the power grid infrastructure with many important functions (ability to reconfigure the system topology, isolate equipment for maintenance and repair, monitor and communicate various system parameters and electrical variables to the control center or elsewhere, actuate control actions or protective relaying decisions, etc.) Substation automation represents one of the fastest evolving parts of the modern (smart) grids and will continue its evolution to keep up with the demands for more flexible and effective monitoring, control, and protection of power systems, both on the transmission and distribution side (see Distribution Systems, Substations, and Integration of Distributed Generation).

A growing part of the distribution networks, especially in developed countries, is being served by underground cables instead of overhead lines. There are many reasons in favor of such solutions (reliability, esthetics of the area where underground lines are installed, less vulnerability to the elements, etc.) and some against (considerably higher cost, faster pace of aging, especially due to moisture and impulse electrical stress, such as a consequence of lightning strikes in vicinity of the installations, and lack of effective diagnostic procedures to assess the operational status and effective remaining lifetime of the cables, more expensive repairs, etc.) Nevertheless, underground distribution (and in some places, underground transmission) represent a growing portion of the energy systems' assets, both in terms of importance and cost, and considerable care needs to be paid to their management and upkeep (see Underground Cable Systems).

Distributed generation (DG) can be defined as small-scale, dispersed, decentralized, and on-site electric energy systems. Currently, capacities of DGs vary typically in the range of several kW to hundreds of MW. As more DG penetrates the electric energy systems, more accurate and efficient system analysis algorithms are needed in order to analyze the impact of the DG system on various types of microgrids and distribution networks. Since DG can change the operation of the distribution system and interfere with its protection and control, electric power utilities are not motivated to interconnect customer-owned small generators to their distribution networks. Utilities tend to put nonutility generation under the extensive technical analysis. Conversely, the regulating authorities tend to act in favor of DG owners and support that the interconnection be as easy and transparent as possible. Nevertheless, the favorable economic features of small-scale distributed generators, especially those using the renewable energy resources as input, will make them increasingly popular and much more widespread than they are at the moment of creation of this text. Even now, many countries (Ireland, Spain, Denmark, etc.) possess considerable renewable resources as part of their generation portfolios. At the time when wind generation of electricity is the fastest growing new generation technology (in terms of new installed capacity) and when the energy produced by renewable resources (including hydro plants) is already larger than energy obtained from the nuclear power plants (United States in 2011), engineering challenges of planning, operating, controlling, and protecting the new power grids are substantial and require major transformative changes (see Renewable Generation, Integration of). This may become even more important as some countries elect to gradually abandon conventional nuclear generation and transition to other, more sustainable, generation resources.

One of the fundamental constraints in the transmission and distribution of electricity is that, for the most part, electrical energy cannot be stored, and therefore must be generated whenever needed. Few exceptions to that limitation have been found and exploited. The biggest problem is that currently available storage options cannot effectively be used at utility-scale capacities (pumped hydro plants are the best known among them). In the interim, a large number of smaller capacity storage technologies have been developed and advanced (superconductive magnetic storage, flywheel, battery storage, etc.), mostly to find applications as uninterruptible power supplies for critically important (but relatively small) loads and rarely exceed the capacities needed to achieve similar effects in the bulk power networks. When a storage technology is developed and commercialized to operate at such large capacity levels economically, it will trigger a major revolution in power grid planning and operation.

A very advanced infrastructure of monitoring, control, and protection (see Wide Area Monitoring, Protection and Control) is required to enable real-time balancing between electric generation and energy demand due to the lack of effective storage options. If generation and consumption of electric energy are not in balance or if the complex infrastructure of voltage control across the system is challenged by the heavy loading conditions and/or the aftermath of an unforeseen major disruption in system operation (such as the outage of a major piece of equipment), generation plants and transmission lines can shut down which may lead to a major blackout. Sometimes such blackouts develop spontaneously in a cascading chain of equipment outages caused by spreading of the overloads through the equipment systemwide as a consequence of an initial disturbance, which may be relatively minor in its initial effects. These series of events may occur in unanticipated sequence, and can be hard to foresee even with large computers. An unexpected contingency may cause an amplifying effect of larger sequential outages and progressively stress the system to the point when the disturbance can no longer be contained. In the domain of large power grids, "flapping of the butterfly wings" in certain places can literally produce a "storm" in others (see Transmission Blackouts: Risk, Causes, and Mitigation).

To reduce the risk of such failures, electric transmission networks are highly meshed and interconnected into regional, national, or continental wide networks, providing multiple redundant alternate paths for energy to flow when needed. Considerable effort is expended by electric utility companies to ensure that sufficient spare capacity and redundant pathways for energy transfer are always available to mitigate the consequences of even large multiple disruptions of the network. In order to maintain sufficient security margins under the threat of multiple unpredictable contingencies, well-coordinated plans for preemptive (slower, based on extensive optimization algorithms applied to coordinate generation and control system wide) and preventive (much faster, emergency control and protection) actions need to be developed so that the system does not descend into a blackout and necessitate lengthy and costly restoration procedures (see Smart Grids, Distributed Control for). Particular focus should be on determining the ability of system to survive extreme contingencies, triggered by very unlikely chains of events, but capable of propagating into costly widespread outages with long-term consequences for both consumers and the power companies.

All of the above functional characteristics and solutions describe what is commonly referred to as smart grid. Gradual application of emerging technologies for advanced power grid management and control/protection represents an effective transition to smart grid, which from the perspective of different authors and researchers may assume different characteristics, but in general shares the following functional properties:

- Ability to resiliently recover to the extent possible from the effects of damaging or disruptive disturbances (self-healing)
- Providing opportunities for consumer participation in energy management and demand response (often via advanced metering options which may provide additional support and information, both for the utility and the customer, during normal operation)
- Ability to respond to, cope with, and resiliently enhance itself against physical and cyber attacks
- Providing power quality for modern equipment anticipated to be needed in the future
- Accommodating all generation and storage options
- Enabling new products, services, and markets
- Optimizing assets and operating efficiently

The transition to smart grid may in some cases be spontaneously driven by obvious benefits and cost-effectiveness, in others may be supported by regulatory and policy actions (see Sustainable Smart Grids, Emergence of a Policy Framework).

Chapter 2
Distribution Systems, Substations, and Integration of Distributed Generation

John D. McDonald, Bartosz Wojszczyk, Byron Flynn, and Ilia Voloh

Glossary

Demand response	Allows the management of customer consumption of electricity in response to supply conditions.
Distributed generation	Electric energy that is distributed to the grid from many decentralized locations, such as from wind farms and solar panel installations.
Distribution grid	The part of the grid dedicated to delivering electric energy directly to residential, commercial, and industrial electricity customers.
Distribution management system	A smart grid automation technology that provides real time about the distribution network and allows utilities to remotely control devices in the grid.
Distribution substation	Delivers electric energy to the distribution grid.
Distribution system	The link from the distribution substation to the customer.

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3

J.D. McDonald (✉)
GE Energy, Digital Energy, 4200 Wildwood Parkway, Atlanta, GA 30339, USA
e-mail: j.d.mcdonald@ieee.org; johnd.mcdonald@ge.com

B. Wojszczyk • B. Flynn • I. Voloh
GE Energy, Digital Energy, 20 Technology Parkway, Suite 380, Norcross, GA 30092-2929, USA
e-mail: Bartosz.Wojszczyk@ge.com; byron.flynn@ge.com

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*, DOI 10.1007/978-1-4614-5830-2_2, © Springer Science+Business Media New York 2013

Renewable energy	Energy from natural resources such as sunlight, wind, rain, tides, biofuels, and geothermal heat, which are naturally replenished.
Smart grid	A modernization of the electricity delivery system so it monitors, protects, and automatically optimizes the operation of its interconnected elements.

Definition of the Subject

This entry describes the major components of the electricity distribution system – the distribution network, substations, and associated electrical equipment and controls – and how incorporating automated distribution management systems, devices, and controls into the system can create a "smart grid" capable of handling the integration of large amounts of distributed (decentralized) generation of sustainable, renewable energy sources.

Introduction

Distributed generation (DG) or decentralized generation is not a new industry concept. In 1882, Thomas Edison built his first commercial electric plant – "Pearl Street." The Pearl Street station provided 110 V direct current (DC) electric power to 59 customers in lower Manhattan. By 1887, there were 121 Edison power stations in the United States delivering DC electricity to customers. These early power plants ran on coal or water. Centralized power generation became possible when it was recognized that alternating current (AC) electricity could be transported at relatively low costs with reduced power losses across great distances by taking advantage of the ability to raise the voltage at the generation station and lower the voltage near customer loads. In addition, the concepts of improved system performance (system stability) and more effective generation asset utilization provided a platform for wide-area grid integration. Recently, there has been a rapidly growing interest in wide deployment of distributed generation, which is electricity distributed to the grid from a variety of decentralized locations. Commercially available technologies for distributed generation are based on wind turbines, combustion engines, micro- and mini-gas turbines, fuel cells, photovoltaic (solar) installations, low-head hydro units, and geothermal systems.

Deregulation of the electric utility industry, environmental concerns associated with traditional fossil fuel generation power plants, volatility of electric energy costs, federal and state regulatory support of "green" energy, and rapid technological developments all support the proliferation of distributed generation in electric utility systems. The growing rate of DG deployment also suggests that alternative energy-based solutions will play an increasingly important role in the smart grid and modern utility.

Large-scale implementation of distributed generation can lead to the evolution of the distribution network from a "passive" (local/limited automation, monitoring, and control) system to an "active" (global/integrated, self-monitoring, semiautomated) system that automatically responds to the various dynamics of the electric grid, resulting in higher efficiency, better load management, and fewer outages. However, distributed generation also poses a challenge for the design, operation, and management of the power grid because the network no longer behaves as it once did. Consequently, the planning and operation of new systems must be approached differently, with a greater amount of attention paid to the challenges of an automated global system.

This entry describes the major components and interconnected workings of the electricity distribution system, and addresses the impact of large-scale deployment of distributed generation on grid design, reliability, performance, and operation. It also describes the distributed generation technology landscape, associated engineering and design challenges, and a vision of the modern utility.

Distribution Systems

Distribution systems serve as the link from the distribution substation to the customer. This system provides the safe and reliable transfer of electric energy to various customers throughout the service territory. Typical distribution systems begin as the medium-voltage three-phase circuit, typically about 30–60 kV, and terminate at a lower secondary three- or single-phase voltage typically below 1 kV at the customer's premise, usually at the meter.

Distribution feeder circuits usually consist of overhead and underground circuits in a mix of branching laterals from the station to the various customers. The circuit is designed around various requirements such as required peak load, voltage, distance to customers, and other local conditions such as terrain, visual regulations, or customer requirements. These various branching laterals can be operated in a radial configuration or as a looped configuration, where two or more parts of the feeder are connected together usually through a normally open distribution switch. High-density urban areas are often connected in a complex distribution underground network providing a highly redundant and reliable means connecting to customers. Most three-phase systems are for larger loads such as commercial or industrial customers. The three-phase systems are often drawn as one line as shown in the following distribution circuit drawing (Fig. 2.1) of three different types of circuits.

The secondary voltage in North America and parts of Latin America consists of a split single-phase service that provides the customer with 240 and 120 V, which the customer then connects to devices depending on their ratings. This is served from a three-phase distribution feeder normally connected in a Y configuration consisting of a neutral center conductor and a conductor for each phase, typically assigned a letter A, B, or C.

Single-phase customers are then connected by a small neighborhood distribution transformer connected from one of the phases to neutral, reducing the voltage from

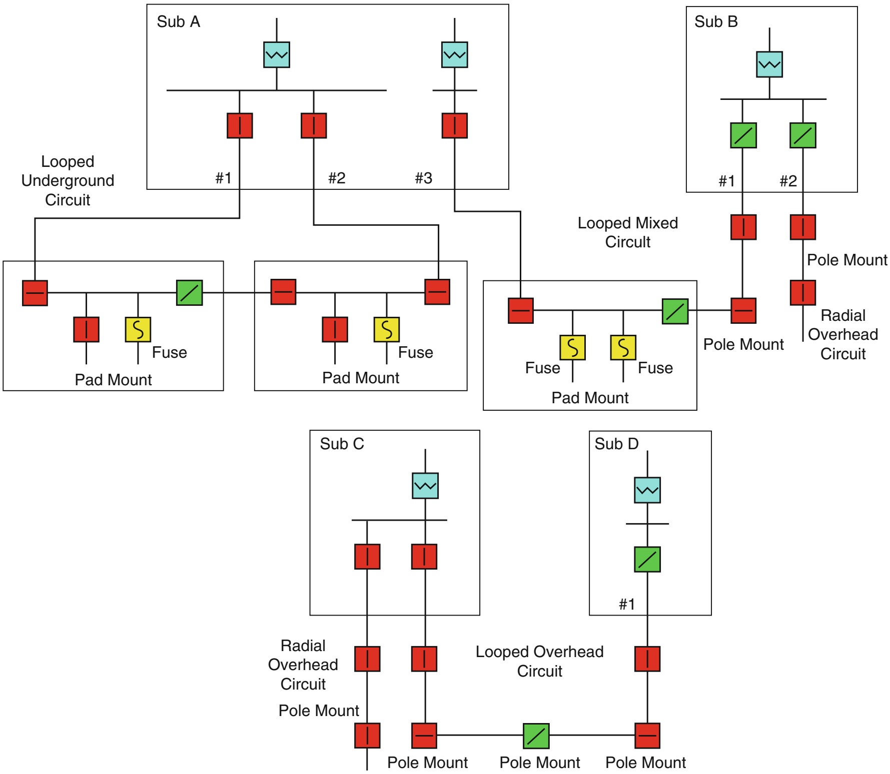


Fig. 2.1 Simple distribution system single line drawings

the primary feeder voltage to the secondary split service voltage. In North America, normally 10 or fewer customers are connected to a distribution transformer.

In most other parts of the world, the single-phase voltage of 220 or 230 V is provided directly from a larger neighborhood distribution transformer. This provides a secondary voltage circuit often serving hundreds of customers.

Figure 2.1 shows various substations and several feeders serving customers from those substations. In Fig. 2.1, the primary transformers are shown as blue boxes in the substation, various switches, breakers, or reclosers are shown as red (closed) or green (open) shapes, and fuses are shown as yellow boxes.

Distribution Devices

There are several distribution devices used to improve the safety, reliability, and power quality of the system. This section will review a few of those types of devices.

Fig. 2.2 Distribution pad-mount switch

Fig. 2.3 Distribution pole-mounted reclosing relay

Switches: Distribution switches (Fig. 2.2) are used to disconnect various parts of the system from the feeder. These switches are manually, remotely, or automatically operated. Typically, switches are designed to break load current but not fault current and are used in underground circuits or tie switches.
Breakers: Like switches, distribution breakers are used to disconnect portions of the feeder. However, breakers have the ability to interrupt fault current. Typically, these are tied to a protective relay, which detects the fault conditions and issues the open command to the breaker.

Reclosers: These are a special type of breaker (Fig. 2.3), typically deployed only on overhead and are designed to reduce the outage times caused by momentary faults. These types of faults are caused by vegetation or temporary short circuits. During the reclose operation, the relay detects the fault, opens the switch, waits a few seconds, and issues a close. Many overhead distribution faults are successfully cleared and service is restored with this technique, significantly reducing outage times.

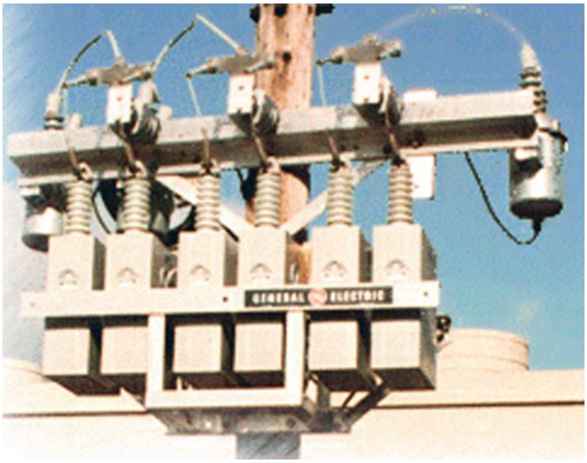


Fig. 2.4 Distribution overhead 600 kVA capacitor

Capacitors: These are three-phase capacitors designed to inject volt amp reactives (VARs) into the distribution circuit, typically to help improve power factor or support system voltage (Fig. 2.4). They are operated in parallel with the feeder circuit and are controlled by a capacitor controller. These controllers are often connected to remote communications allowing for automatic or coordinated operation.

Fuses: These are standard devices used to protect portions of the circuit when a breaker is too expensive or too large. Fuses can be used to protect single-phase laterals off the feeder or to protect three-phase underground circuits.

Lightning arresters: These devices are designed to reduce the surge on the line when lightning strikes the circuit.

Automation Scheme: FDIR

The following description highlights an actual utility's FDIR automation scheme, their device decisions, functionality and system performance. Automation sequences include fault detection, localization, isolation, and load restoration (FDIR). These sequences will detect a fault, localize it to a segment of feeder, open the switches around the fault, and restore un-faulted sources via the substation and alternative sources as available. These algorithms work to safely minimize the fault duration and extent, significantly improving the SAIDI (system average interruption duration index) and SAIFI (system average interruption frequency Index) performance metric for the customers on those feeders. An additional important sequence is the automatic check of equipment loading and thermal limits to determine whether load transfers can safely take place.

Modern systems communicate using a secure broadband Ethernet radio system, which provides significant improvement over a serial system, including supporting peer-to-peer communications, multiple access to tie switches, and remote access by

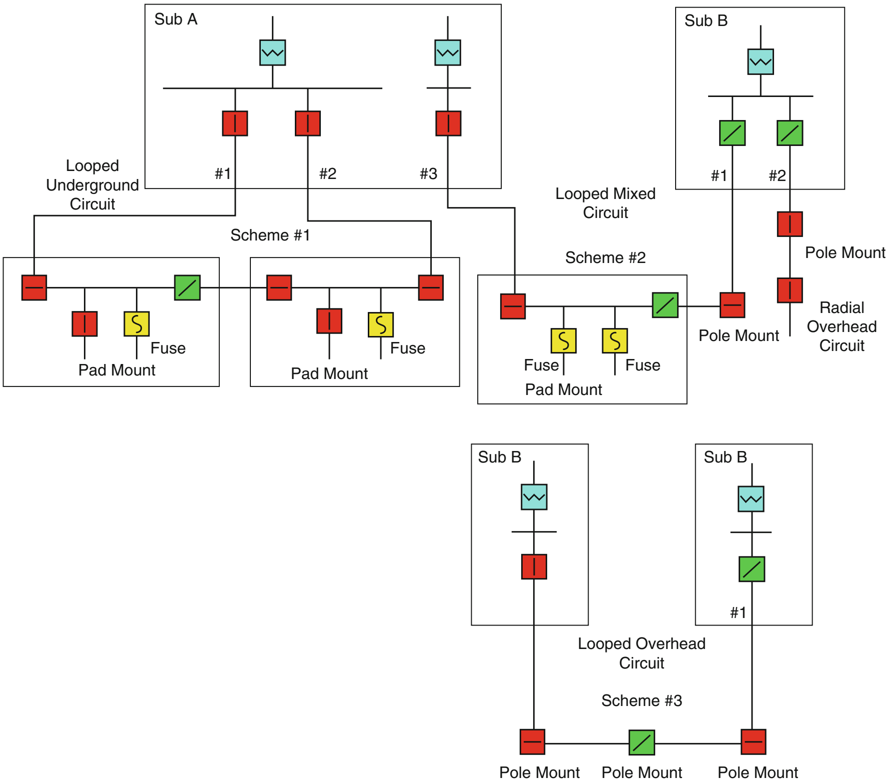


Fig. 2.5 Distribution automation (DA) system single lines

communications and automation maintenance personnel. The communication system utilizes an internet protocol (IP)–based communication system with included security routines designed to meet the latest NERC (North American Electric Reliability Corporation) or the distribution grid operator's requirements.

Feeder circuits to be automated are typically selected because they have relatively high SAIDI indices serving high-profile commercial sites. Scheme 1 utilized two pad-mount switches connected to one substation. Scheme 2 consisted of a mix of overhead and underground with vault switchgear and a pole-mounted recloser. Scheme 3 was installed on overhead circuits with three pole-mounted reclosers.

Automation Schemes 1, 2 and 3 (Fig. 2.5) were designed to sense distribution faults, isolate the appropriate faulted line sections, and restore un-faulted circuit sections as available alternate source capacity permitted.

Safety

Safety is a critical piece of system operation. Each algorithm has several safety checks before any operation occurs. Before the scheme logic is initialized, a series of checks occur, including:

- Auto Restoration is enabled on a specific scheme – dispatchers do this via the distribution management system or SCADA system.
- Auto Restoration has not been disabled by a crew in the field via enable/disable switches at each device location.
- Auto Restoration has been reset – each scheme must be reset by the dispatcher after DA has operated and system has been restored to normal configuration.
- Communications Status – verifies that all necessary devices are on-line and communicating.
- Switch Position – verifies that each appropriate line switch is in the appropriate position (see Fig. 2.1).
- Voltages – checks that the appropriate buses/feeders are energized.
- Feeder Breaker Position – verifies the faulted feeder breaker has locked open and was opened only by a relay, not by SCADA or by the breaker control handle.

Prior to closing the tie switch and restoring customers in un-faulted sections, the following safety checks occur:

- Determine Pre-Fault Load – determine pre-fault load on un-faulted section of line.
- Compare Pre-Fault Load to Capacity – determine if alternate source can handle the un-faulted line section load.

After any DA algorithm executes:

- Notifies Dispatch of Status of DA System – success or failure of restoring load in un-faulted line sections.
- Reset is Necessary – algorithm is disabled until reset by dispatcher once the fault is repaired and the system is put back to normal configuration (see Fig. 2.1).

In summary, automation can occur *only* if these five conditions are true for every device on a scheme:

- Enable/Disable Switch is in enable position
- Local/Remote switch is in remote
- Breaker “hot-line” tag is off.
- Breaker opens from a relay trip and stays open for several seconds (that is, goes to lockout).
- Dispatch has reset the scheme(s) after the last automation activity.

Each pad-mounted or pole-mounted switch has a local enable/disable switch as shown in Fig. 2.6. Journeymen are to use these switches as the primary means of disabling a DA scheme before starting work on any of the six automated circuits or circuit breakers or any of the seven automated line switches.

FDIR System Components

The automation system consists of controllers located in pad-mount switches, pole-mounted recloser controls (Fig. 2.7), and in substations (Fig. 2.8).

Fig. 2.6 Pad-mount controller and pole-mount reclosing relay with enable/disable switches

Fig. 2.7 Typical pad-mount and pole-mount switches

Fig. 2.8 Typical substation controller and vault switch

Pad-Mounted Controller

The pad-mounted controller was selected according to the following criteria:

- Similar to existing substation controllers – simplifying configuration and overall compatibility
- Compatible with existing communications architecture
- Uses IEC 61131-3 programming
- Fault detection on multiple circuits
- Ethernet connection
- Supports multiple master stations
- Installed cost

The pad-mounted controller (Fig. 2.7) selected was an Ethernet-based controller that supported the necessary above requirements. The IEC 61131-3 programming languages include:

- Sequential Function Chart – describes operations of a sequential process using a simple graphical representation for the different steps of the process, and conditions that enable the change of active steps. It is considered to be the core of the controller configuration language, with other languages used to define the steps within the flowchart.
- Flowchart – a decision diagram composed of actions and tests programmed in structured text, instruction list, or ladder diagram languages. This is a proposed IEC 61131-3 language.
- Function Block Diagram – a graphic representation of many different types of equations. Rectangular boxes represent operators, with inputs on the left side of the box and outputs on the right. Custom function blocks may be created as well. Ladder diagram expressions may be a part of a function block program.
- Ladder Diagram – commonly referred to as "quick LD," the LD language provides a graphic representation of Boolean expressions. Function blocks can be inserted into LD programs.
- Structured Text – high-level structured language designed for expressing complex automation processes which cannot be easily expressed with graphic languages. Contains many expressions common to software programming languages (CASE, IF-THEN-ELSE, etc.). It is the default language for describing sequential function chart steps.
- Instruction List – a low-level instruction language analogous to assembly code.

Pole-Mounted Controller with Recloser

The recloser controller was selected according to the following criteria:

- Similar requirements to pad-mounted controllers
- Control must provide needed analog and status outputs to DA remote terminal units (RTU)

Substation Controller

The substation controller (Fig. 2.8) was selected per the following criteria:

- Similar to field controllers – simplifying configuration and overall compatibility
- Compatible with communications architecture
- Uses IEC 61131-3
- Ethernet and serial connections
- Supports multiple master stations including master station protocols
- Remote configuration is supported

Communications System

General

The primary requirement of the communications system was to provide a secure channel between the various switches and the substation. The communication channel also needed to allow remote connection to the switchgear intelligent electronic devices (IEDs) for engineers and maintenance personnel. Additionally, the DA system also required the support for multiple substation devices to poll the controller at the tie switch. These requirements indicated the need for multi-channel or broadband radio.

Radio Communication Selection Criteria

Primary considerations for selecting radio communications include:

- Security
- Supports remote configuration
- Broadband or multiple channels
- Compatible with multiple protocols
- From a major supplier
- Installed cost

The radio selected is a broadband radio operating over 900 MHz spread spectrum and 512 kbps of bandwidth. The wide-area network (WAN), Ethernet-based radio, supports the necessary protocols and provides multiple communications channels.

The communications network operates as a WAN providing the capability to communicate between any two points simply by plugging into the 10baseT communications port. A DA maintenance master was installed to communicate with the various controllers and to provide a detailed view of the DA system from the dispatch center. The DA system was also connected to the dispatch master station, which gives the dispatcher the ability to monitor and control the various DA algorithms and, in the future, typical SCADA control of the switches using distribution network protocol (DNP). (Since the dispatch master station currently does not support DNP over IP, a serial to Ethernet converter will be installed at the dispatch center to handle the conversion). Figure 2.9 illustrates the communications architecture.

The radios communicate using point to multi-point with an access point radio operating as the base station radio and two types of remote radios, with serial or Ethernet. Some of the remote controllers only used DNP serial channels, requiring the radios to convert the serial connection to Ethernet. The remote Ethernet-based devices connect to the radios using a standard 10BaseT connection. Refer to Fig. 2.9.

For sites that require multiple DNP masters to connect to the serial controllers, the radios and the controllers have two serial connections. A new feature of the serial controllers is the support of point-to-point protocol (PPP). PPP provides a method for transmitting datagrams over serial point-to-point links. PPP contains three main components:

- A method for encapsulating datagrams over serial links. PPP uses the high-level data link control (HDLC) protocol as a basis for encapsulating datagrams over point-to-point links.
- An extensible Link Control Protocol (LCP) which is used to establish, configure, maintain, terminate, and test the data link connection.
- A family of network control protocols (NCP) for establishing and configuring different network layer protocols after LCP has established a connection. PPP is designed to allow the simultaneous use of multiple network layer protocols.

Establishing a PPP connection provides support for DNP multiple masters and a remote connection for maintenance over one serial communication line, effectively providing full Ethernet functionality over a single serial channel.

Security

The wireless system contains several security features. Table 2.1 outlines the threat and the security measures implemented in the radio to meet these threats.

Automation Functionality

Distribution Automation Schemes

Distribution automation (DA) scheme operation is discussed in this section. All three schemes are configured the same, differing only in the type of midpoint and tie point switches used and whether the two sources are in the same or different

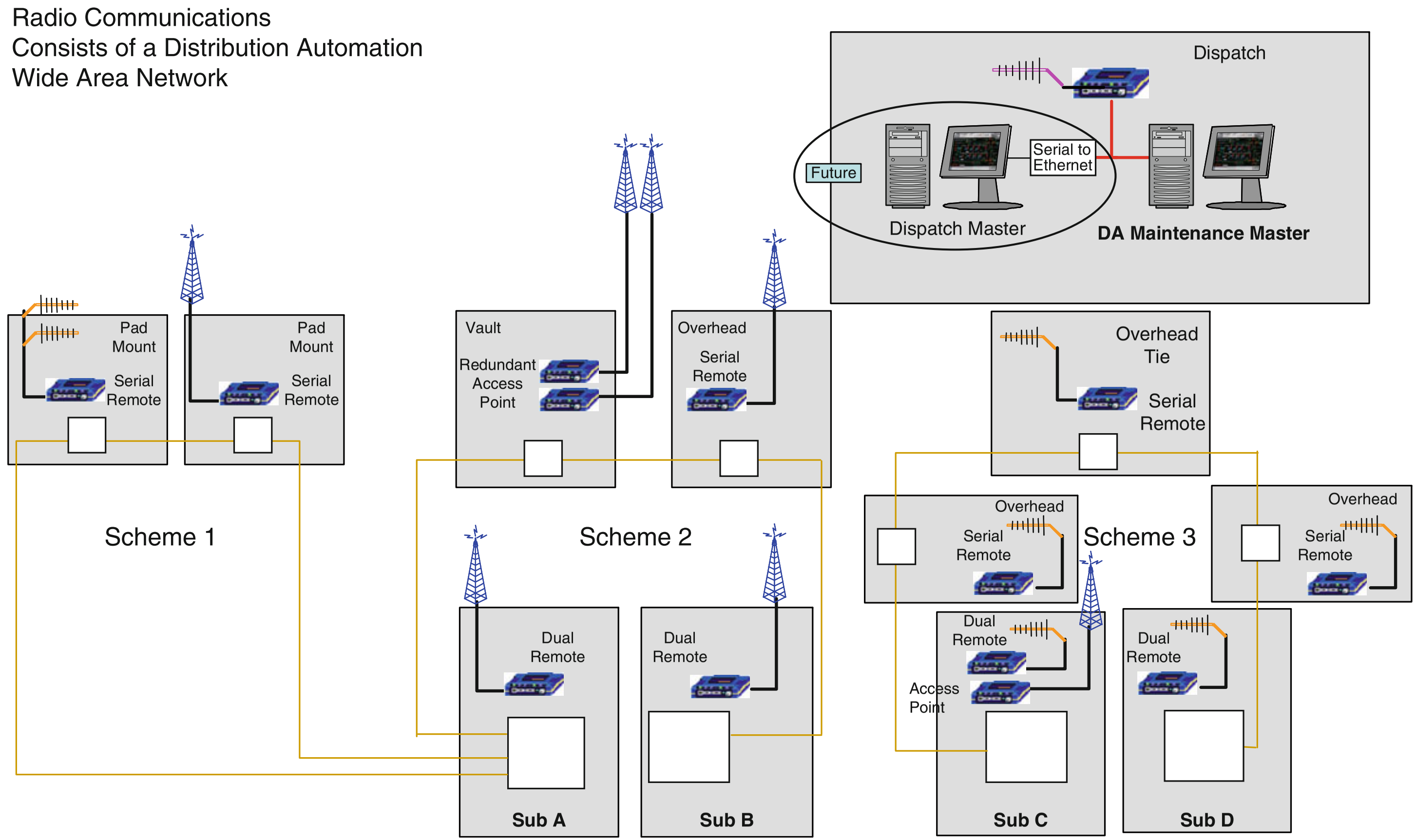


Fig. 2.9 DA communications infrastructure

Table 2.1 Security risk management

Security threat	900 MHz radio security
Unauthorized access to the backbone network through a foreign remote radio	Approved remotes list. Only those remotes included in the AP list will connect
"Rogue" AP, where a foreign AP takes control of some or all remote radios and thus remote devices	Approved AP List. A remote will only associate to those AP included in its local
Dictionary attacks, where a hacker runs a program that sequentially tries to break a password	Failed-login lockdown. After three tries, the transceiver ignores login requests for 5 min. Critical event reports (traps) are generated as well
Denial of service, where Remote radios could be reconfigured with bad parameters bringing the network down	• Remote login • Local console login • Disabled HTTP and Telnet to allow only local management services
Airwave searching and other hackers in parking lots, etc.	• 900 MHz FHSS does not talk over the air with standard 802.11b cards. • The transceiver cannot be put in a promiscuous mode. • Proprietary data framing
Eavesdropping, intercepting messages	128-bit encryption
Key cracking	Automatic rotating key algorithm
Replaying messages	128-bit encryption with rotating keys
Unprotected access to configuration via SNMPv1	Implement SNMPv3 secure operation
Intrusion detection	Provides early warning via SNMP through critical event reports (unauthorized, logging attempts, etc.)

substations. All three are set up as two-zone circuit pairs, with one tie point and two midpoints. Only one scheme will be shown (Fig. 2.10), as the others are analogous. Scheme 1 operates on the system shown in Fig. 2.10. It consists of two pad-mount switches and one substation. The pad-mount controllers communicate with the controller in the substation and the substation controller communicates with the DA maintenance master station and, in the future, the dispatch master.

Zone 1 Permanent Fault

Before the algorithm operates, the safety checks occur as previously described. Refer to Figs. 2.11 and 2.12. If a permanent Zone 1 fault occurs (between switch 1 and substation CB14) and the algorithm is enabled and the logic has been initialized, the following actions occur:

1. After relaying locks out the substation breaker, the algorithm communicates with the field devices and the station protection relays to localize the fault.
2. Algorithm determines fault is between the substation and SW1.

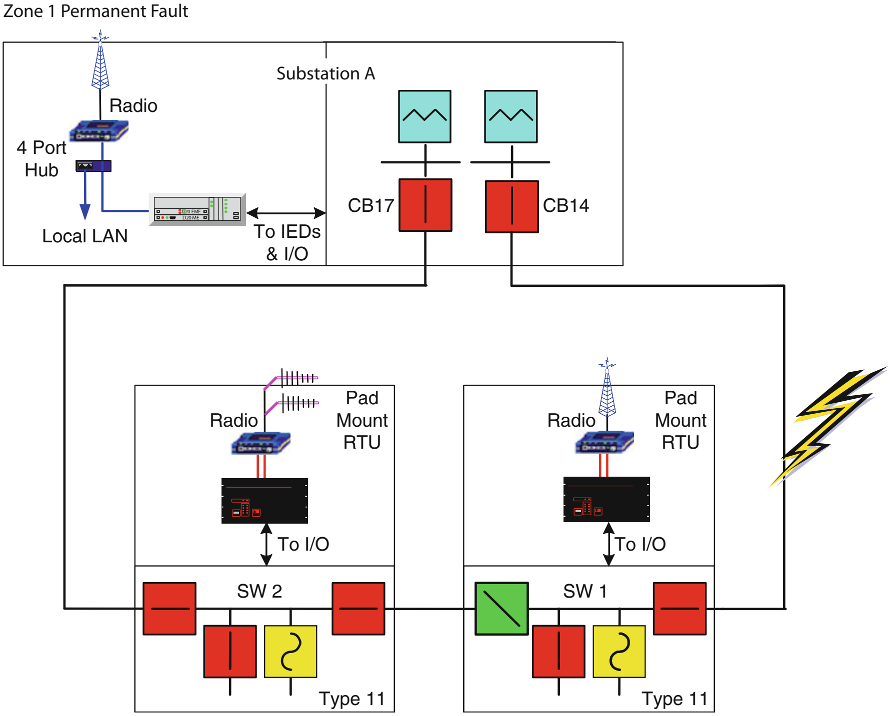


Fig. 2.10 Scheme 1 architecture

3. Algorithm opens the circuit at SW1 connected to the incoming line from the substation, isolating the fault.
4. Algorithm gathers pre-fault load of section downstream of SW1 from the field devices.
5. Algorithm determines if capacity exists on alternate source and alternate feeder.
6. If so, algorithm closes the tie switch and backfeeds load, restoring customers on un-faulted line.
7. Reports successful operation to dispatch. The system is now as shown in Figs. 2.11 and 2.12, resulting in a reduction of SAIFI and SAIDI.

Zone 1 Permanent Fault: Load Too High to Safely Transfer

In this case, a Zone 1 permanent fault occurs as shown in Fig. 2.13 and the previous example, except that this time loads are too high for the alternate source to accept load from the faulted feeder. Note the dispatch DA screens are descriptive and present information in plain language. Refer to Figs. 2.13 and 2.14.

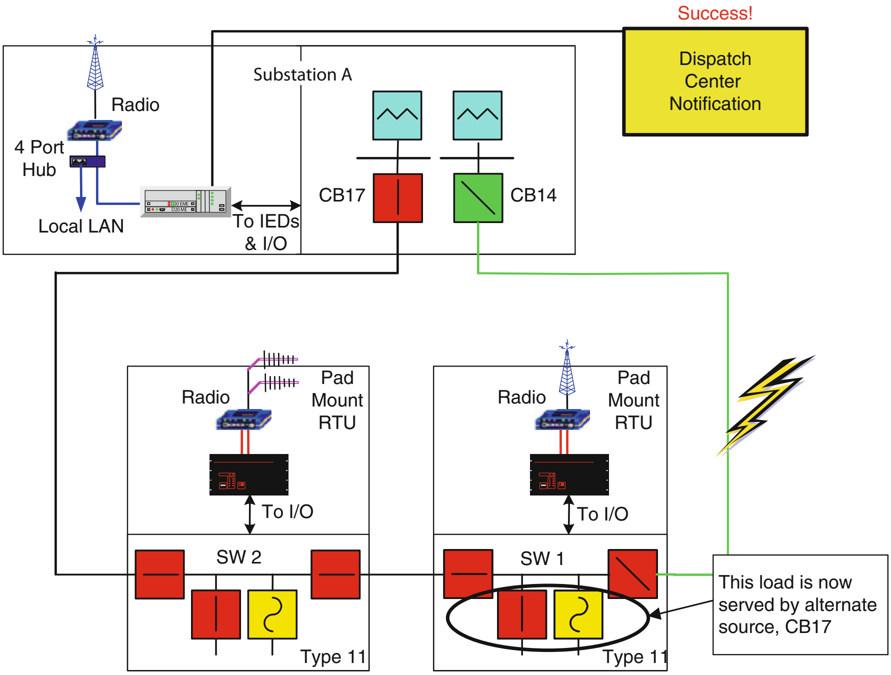


Fig. 2.11 Scheme 1 architecture after successful DA operation

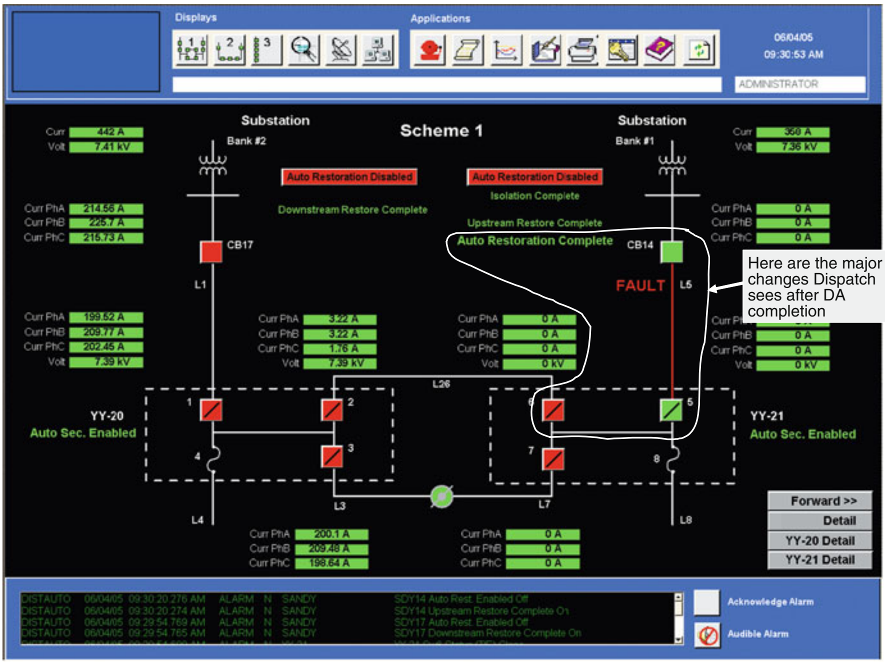


Fig. 2.12 Dispatch notification of scheme 1 isolation/restoration success

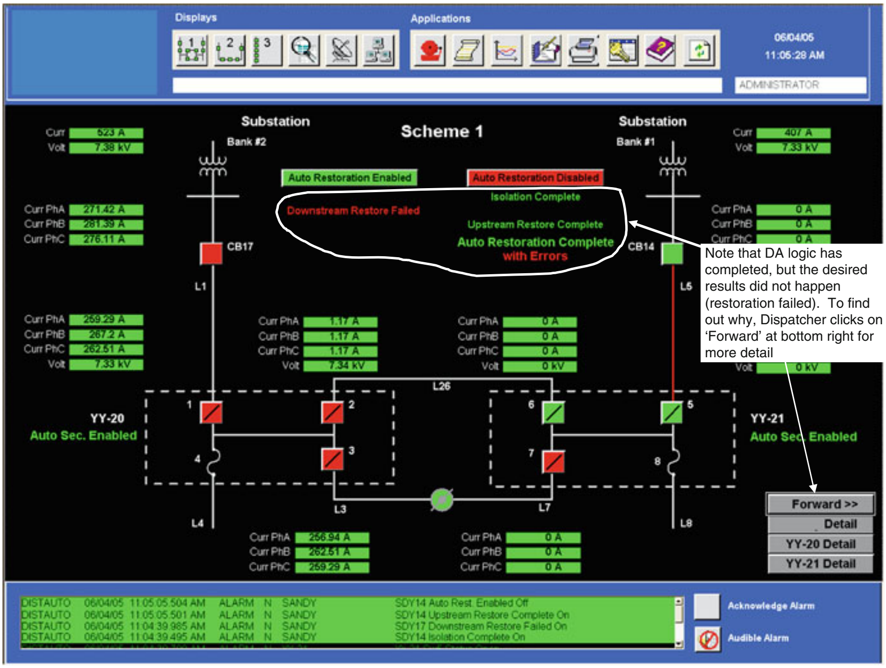


Fig. 2.13 Dispatch notification of scheme 1 restoration failure

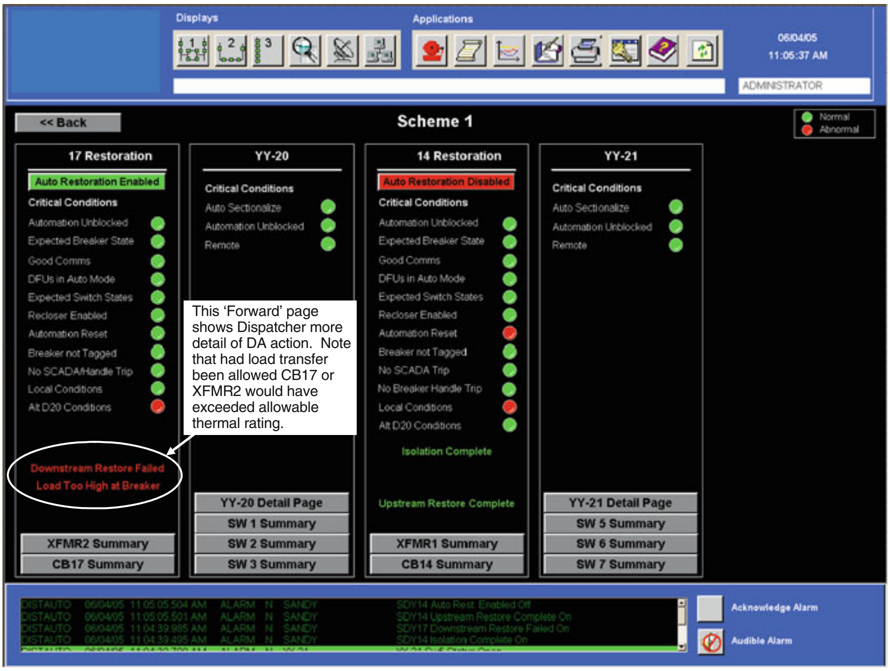


Fig. 2.14 Dispatch detail of scheme 1 restoration failure

Zone 2 Permanent Fault

Depending on the type of the SW1 device (Fig. 2.15), the following actions occur:
If SW1 is a recloser (as in Schemes 2 and 3):

1. SW1 locks out in three shots. If SW1 is a pad-mount switch with no protection package (as in Scheme 1), the substation breaker goes to lockout. Fifty percent of CB11 customers remain in power.
2. This action occurs whether DA is enabled or disabled. That is, *existing circuit protection is unaffected by any DA scheme or logic*.
3. Safety checks are performed to ensure DA can safely proceed.
4. DA logic sees loss of voltage only beyond SW1 (recloser at lockout) and saw fault current through CB11 and SW1, so it recognizes that the line beyond SW1 is permanently faulted.
5. DA will not close into a faulted line, so the alternate source tie point (open point of SW2) remains open.
6. Customers between SW1 and SW2 lose power (about 50% of CB11 customers).

If SW1 is switchgear (as in Scheme 1):

1. Substation circuit breaker, CB11, locks out in three shots.
2. This action occurs whether DA is enabled or disabled. That is, *existing circuit protection is unaffected by any DA scheme or logic*.
3. Safety checks are performed to ensure DA can safely proceed.

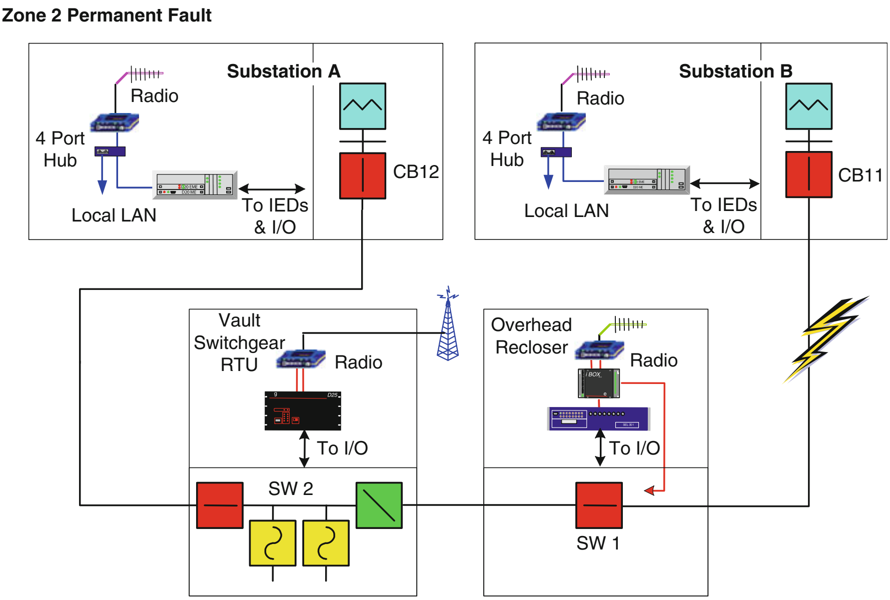


Fig. 2.15 Scheme 2 architecture

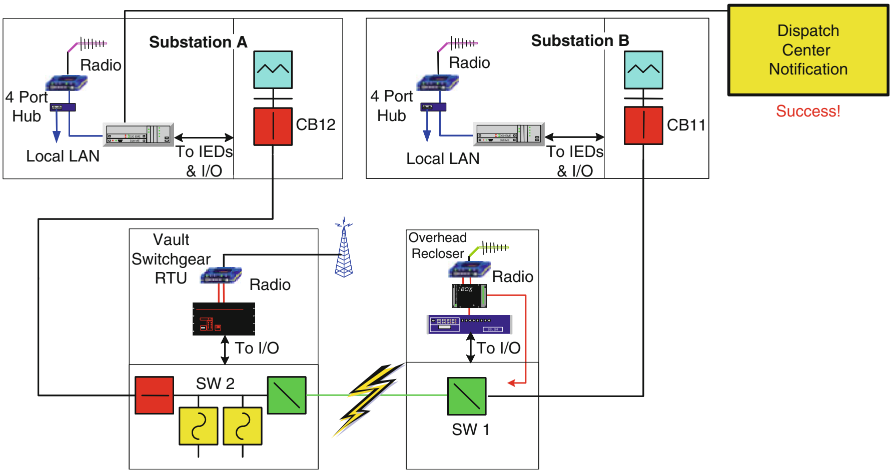


Fig. 2.16 Scheme 2 architecture after successful DA operation

4. DA logic sees loss of voltage beyond CB11 (CB at lockout) and saw fault current through CB11 and SW1, so it recognizes that the line beyond (not before) SW1 is permanently faulted.
5. Fault is isolated by DA logic, sending open command to SW1.
6. DA logic recognizes line upstream of SW1 is good (fault current sensed at two devices), and closes CB11, heating up line to source side of open SW1. Power is now restored to 50% of customers.
7. DA will not close into a faulted line, so the alternate source tie point (open point of SW2) remains open (Figs. 2.16 and 2.17).

System Operation

In 5 months of operation thus far the DA system has operated for 21 faults; all were Zone 2 faults on Scheme 3 (all downstream of the midpoint SW1). Three of those faults were permanent and took the line recloser SW1 to lockout. As a result, in 5 months, the DA pilot has saved 550 customers 6 h of power outage time (i.e., saved 3,300 customer hours lost) and eliminated 18 momentaries for those same 550 customers.

There have been no Zone 1 faults on any scheme; therefore, no load transfers to alternate sources have taken place.

Automation Scheme: Volt/VAR Control (VVC)

General

The various loads along distribution feeders result in resistive (I^2R) and reactive (I^2X) losses in the distribution system. If these losses are left uncompensated, an

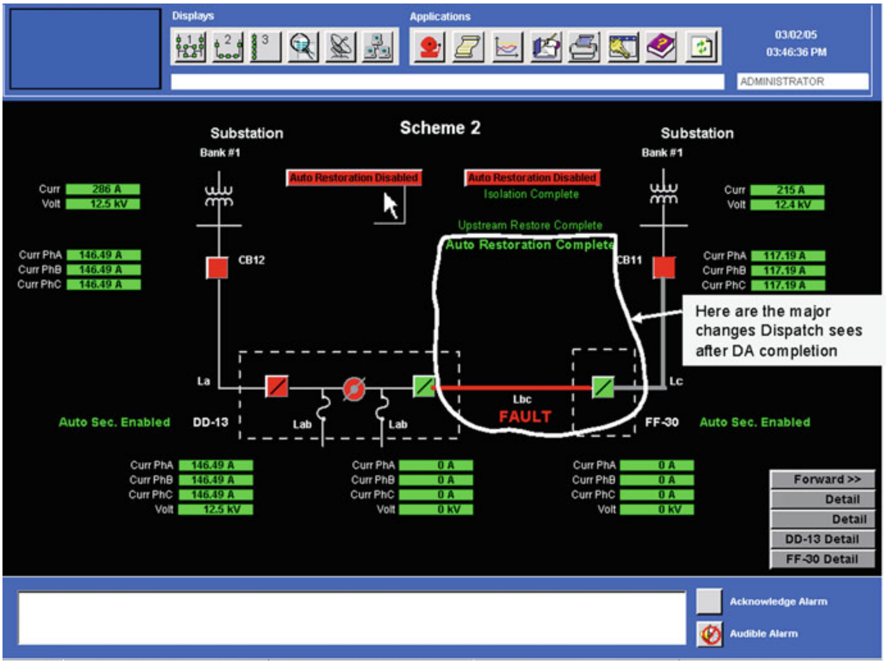


Fig. 2.17 Dispatch notification of scheme 2 isolation/restoration success

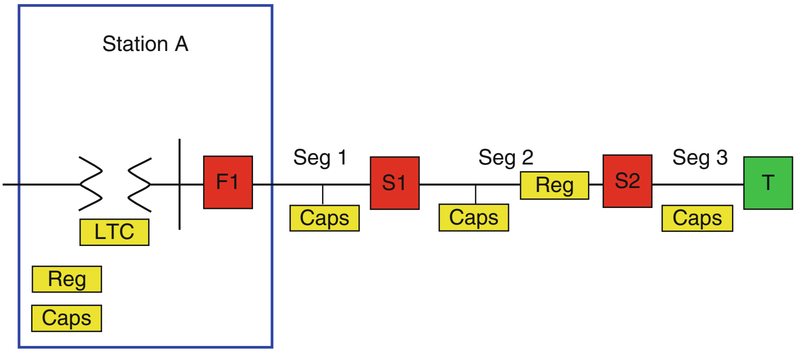


Fig. 2.18 Example station and feeder voltage/VAR control devices

additional problem of declining voltage profile along the feeder will result. The most common solution to these voltage problems is to deploy voltage regulators at the station or along the feeder and/or a transformer LTC (load tap changers) on the primary station transformer; additional capacitors at the station and at various points on the feeder also provide voltage support and compensate the reactive loads. Refer to Fig. 2.18.

Fig. 2.19 Example station and feeder voltage/VAR control devices

Many utilities are looking for additional benefits through improved voltage management. Voltage management can provide significant benefits through improved load management and improved voltage profile management.

The station Volt/VAR equipment consists of a primary transformer with either an LTC (Fig. 2.18) or a station voltage regulator and possibly station capacitors. The distribution feeders include line capacitors and possibly line voltage regulators.

The LTC is controlled by an automatic tap changer controller (ATC). The substation capacitors are controlled by a station capacitor controller (SCC), the distribution capacitors are controlled by an automatic capacitor controller (ACC), and the regulators are controlled by an automatic regulator controller (ARC). These controllers are designed to operate when local monitoring indicates a need for an operation including voltage and current sensing. Distribution capacitors are typically controlled by local power factor, load current, voltage, VAR flow, temperature, or the time (hour and day of week).

Some utilities have realized additional system benefits by adding communications to the substation, and many modern controllers support standard station communications protocols such as DNP.

This system (shown in Figs. 2.19 and 2.20) includes the ability to remotely monitor and manually control the volt/VAR resources, as well as the ability to provide integrated volt/VAR control (IVVC).

Benefits of Volt/VAR Control (VVC)

The VAR control systems can benefit from improved power factor and the ability to detect a blown fuse on the distribution capacitor. Studies and actual field data have indicated that systems often add an average of about 1 MVAR to each feeder. This can result in about a 2% reduction in the losses on the feeder.

Fig. 2.20 Three-phase station voltage regulator

Based on the assumptions, the benefits for line loss optimization that some utilities have calculated represent a significant cost-benefit payback. However, one of the challenges utilities face is that the cost and benefits are often disconnected. The utility's distribution business usually bears the costs for an IVVC system. The loss reduction benefits often initially flow to the transmission business and eventually to the ratepayer, since losses are covered in rates. Successful implementation of a loss reduction system will depend on helping align the costs with the benefits. Many utilities have successfully reconnected these costs and benefits of a Volt/VAR system through the rate process.

The voltage control systems can provide benefit from reduced cost of generation during peak times and improved capacity availability. This allows rate recovery to replace the loss of revenue created from voltage reduction when it is applied at times other than for capacity or economic reasons. The benefits for these programs will be highly dependent on the rate design, but could result in significant benefits.

There is an additional benefit from voltage reduction to the end consumer during off-peak times. Some utilities are approaching voltage reduction as a method to reduce load similar to a demand response (DR) program. Rate programs supporting DR applications are usually designed to allow the utility to recapture lost revenue resulting from a decreased load. In simplified terms, the consumer would pay the utility equal to the difference between their normal rate and the wholesale price of energy based on the amount of load reduction. Figure 2.21 highlights the impact of voltage as a load management tool.

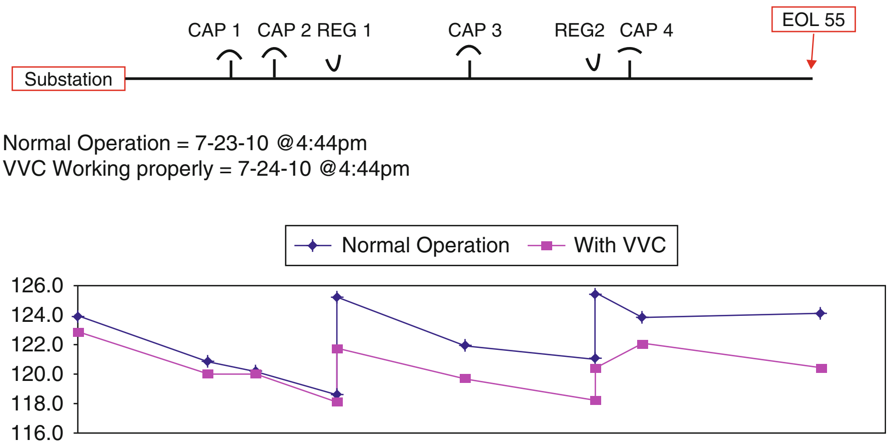
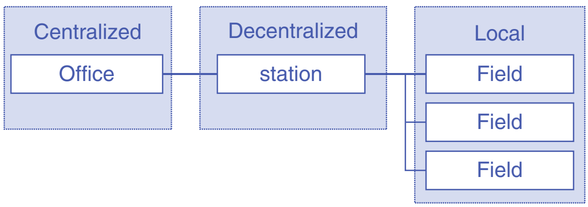


Fig. 2.21 Three-phase station voltage profile

Fig. 2.22 Relationship automation at centralized, decentralized, and local areas



This chart contains real data from a working feeder utilizing Volt/VAR control. As the chart indicates, with VVC, the feeder voltage profile is flatter and lower.

Considerations

Centralized, Decentralized, or Local Algorithm

Given the increasing sophistication of various devices in the system, many utilities are facing a choice of location for the various algorithms (Fig. 2.22). Often it is driven by the unique characteristics of the devices installed or by the various alternatives provided by the automation equipment suppliers.

Table 2.2 compares the various schemes.

Safety and Work Processes

The safety of workers, of the general public, and of equipment must not be compromised. This imposes the biggest challenge for deploying any automatic or

Table 2.2 Three-phase station voltage profile

Centralized	Decentralized	Local
Supports more complex applications such as: Load Flow, DTS, Study	Most station IEDs support automation	Local IEDs often include local algorithms
Support for full network model	Faster response than centralized DA	Usually initiated after prolonged comms outage, e.g., local capacitor controller
Optimizes improvements	Smaller incremental deployment costs	Operates faster than other algorithms usually for protection, reclosing, and initial sectionalizing
Dynamic system configuration	Often used for initial deployment because of the reduced complexity and costs	Usually only operates based on local sensing or peer communications
Automation during abnormal conditions	Typical applications: include: initial response, measure pre-event	Less sophisticated and less expensive
Enables integration with other sources of data – EMS, OMS, AMI, GIS	Flexible, targeted, or custom solution	Easiest to begin deploying
Integration with other processes planning, design, dispatch	Usually cheaper and easier for initial deploy	Hardest to scale sophisticated solutions
Easier to scale, maintain, upgrade, and backup	Hard to scale sophisticated solutions	

remotely controlled systems. New automation systems often require new work processes. Utility work process and personnel must be well trained to safely operate and maintain the new automated distribution grid systems.

Operating practices and procedures must be reviewed and modified as necessary to address the presence of automatic switchgear.

Safety related recommendations include:

- Requirement for "visible gap" for disconnect switches
- No automatic closures after 2 min have elapsed following the initial fault to protect line crews
- System disabled during maintenance ("live line") work, typically locally and remotely

The Law of Diminishing Returns

Larger utilities serve a range of customer types across a range of geographic densities. Consequently, the voltage profile and the exposure to outages are very different from circuit to circuit. Most utilities analyze distribution circuits and deploy automation on the most troublesome feeders first. Figure 2.23 depicts this difference.

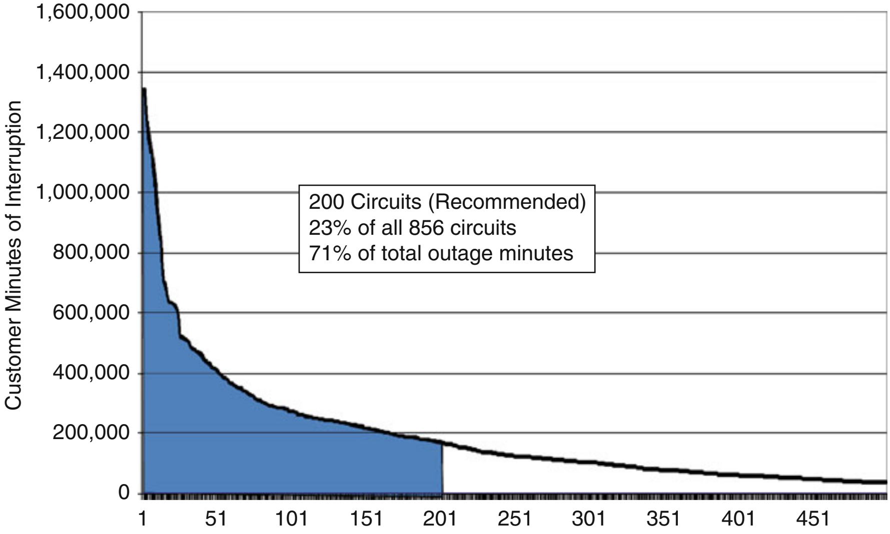


Fig. 2.23 Customer minutes interrupted by feeder

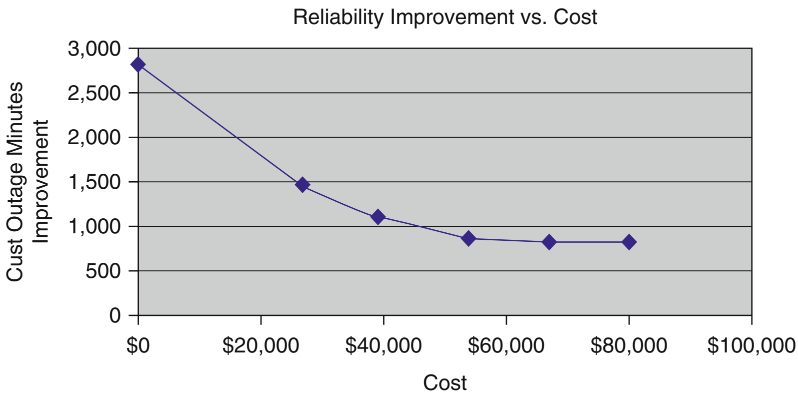


Fig. 2.24 Customer minutes interrupted by cost

Figure 2.23 highlights the decision by one utility to automate roughly 25% of feeders, which account for 70% of overall customer minutes interrupted.

The same analysis can be done on a circuit basis. The addition of each additional sensing and monitoring device to a feeder leads to a diminishing improvement to outage minutes as shown in Fig. 2.24.

Both of these elements are typically studied and modeled to determine the recommended amount of automation each utility is planning.

Substations

Role and Types of Substations

Substations are key parts of electrical generation, transmission, and distribution systems. Substations transform voltage from high to low or from low to high as necessary. Substations also dispatch electric power from generating stations to consumption centers. Electric power may flow through several substations between the generating plant and the consumer, and the voltage may be changed in several steps. Substations can be generally divided into three major types:

1. *Transmission substations* integrate the transmission lines into a network with multiple parallel interconnections so that power can flow freely over long distances from any generator to any consumer. This transmission grid is often called the bulk power system. Typically, transmission lines operate at voltages above 138 kV. Transmission substations often include transformation from one transmission voltage level to another.
2. *Sub-transmission substations* typically operate at 34.5 kV through 138 kV voltage levels, and transform the high voltages used for efficient long distance transmission through the grid to the sub-transmission voltage levels for more cost-effective transmission of power through supply lines to the distribution substations in the surrounding regions. These supply lines are radial express feeders, each connecting the substation to a small number of distribution substations.
3. *Distribution substations* typically operate at 2.4–34.5 kV voltage levels, and deliver electric energy directly to industrial and residential consumers. Distribution feeders transport power from the distribution substations to the end consumers' premises. These feeders serve a large number of premises and usually contain many branches. At the consumers' premises, distribution transformers transform the distribution voltage to the service level voltage directly used in households and industrial plants, usually from 110 to 600 V.

Recently, distributed generation has started to play a larger role in the distribution system supply. These are small-scale power generation technologies (typically in the range of 3–10,000 kW) used to provide an alternative to or an enhancement of the traditional electric power system. Distributed generation includes combined heat and power (CHP), fuel cells, micro-combined heat and power (micro-CHP), micro-turbines, photovoltaic (PV) systems, reciprocating engines, small wind power systems, and Stirling engines, as well as renewable energy sources.

Renewable energy comes from natural resources such as sunlight, wind, rain, tides, and geothermal heat, which are naturally replenished. New renewables (small hydro, modern biomass, wind, solar, geothermal, and biofuels) are growing very rapidly.

A simplified one-line diagram showing all major electrical components from generation to a customer's service is shown in Fig. 2.25.

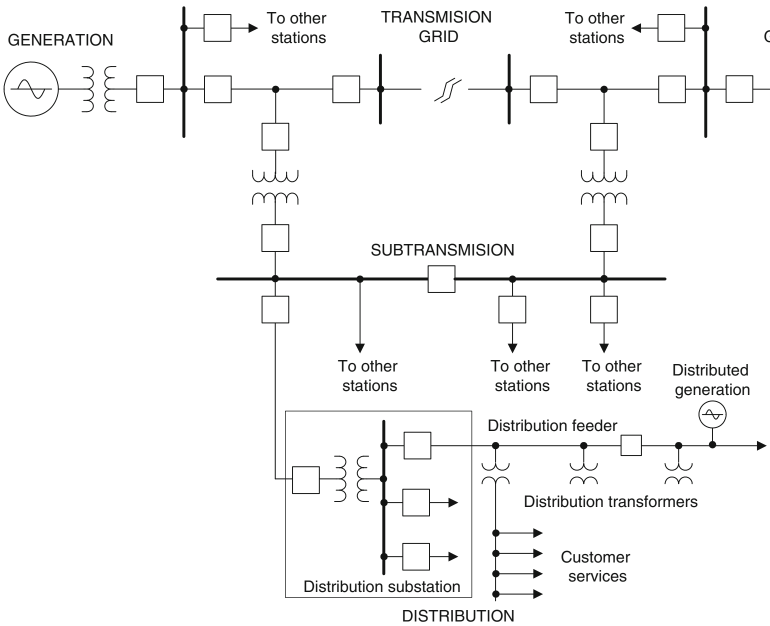


Fig. 2.25 One-line diagram of major components of power system from generation to consumption

Distribution Substation Components

Distribution substations are comprised of the following major components.

Supply Line

Distribution substations are connected to a sub-transmission system via at least one supply line, which is often called a primary feeder. However, it is typical for a distribution substation to be supplied by two or more supply lines to increase reliability of the power supply in case one supply line is disconnected. A supply line can be an overhead line or an underground feeder, depending on the location of the substation, with underground cable lines mostly in urban areas and overhead lines in rural areas and suburbs. Supply lines are connected to the substation via high-voltage disconnecting switches in order to isolate lines from substation to perform maintenance or repair work.

Transformers

Transformers “step down” supply line voltage to distribution level voltage. See Fig. 2.26. Distribution substations usually employ three-phase transformers;

Fig. 2.26 Voltage transformers (Courtesy of General Electric)

however, banks of single-phase transformers can also be used. For reliability and maintenance purposes, two transformers are typically employed at the substation, but the number can vary depending on the importance of the consumers fed from the substation and the distribution system design in general. Transformers can be classified by the following factors:

(a) *Power rating*, which is expressed in kilovolt-amperes (kVA) or megavolts-amperes (MVA), and indicates the amount of power that can be transferred through the transformer. Distribution substation transformers are typically in the range of 3 kVA to 25 MVA.
(b) *Insulation*, which includes liquid or dry types of transformer insulation. Liquid insulation can be mineral oil, nonflammable or low-flammable liquids. The dry type includes the ventilated, cast coil, enclosed non-ventilated, and sealed gas-filled types. Additionally, insulation can be a combination of the liquid-, vapor-, and gas-filled unit.
(c) *Voltage rating*, which is governed by the sub-transmission and distribution voltage levels substation to which the transformer is connected. Also, there are standard voltages nominal levels governed by applicable standards. Transformer voltage rating is indicated by the manufacturer. For example, 115/34.5 kV means the high-voltage winding of the transformer is rated at 115 kV, and the low-voltage winding is rated at 34.5 kV between different phases. Voltage rating dictates the construction and insulation requirements of the transformer to withstand rated voltage or higher voltages during system operation.

(d) *Cooling*, which is dictated by the transformer power rating and maximum allowable temperature rise at the expected peak demand. Transformer rating includes self-cooled rating at the specified temperature rise or forced-cooled rating of the transformer if so equipped. Typical transformer rated winding temperature rise is 55°C/65°C at ambient temperature of 30°C for liquid-filled transformers to permit 100% loading or higher if temporarily needed for system operation. Modern low-loss transformers allow even higher temperature rise; however, operating at higher temperatures may impact insulation and reduce transformer life.

(e) *Winding connections*, which indicates how the three phases of transformer windings are connected together at each side. There are two basic connections of transformer windings; delta (where the end of each phase winding is connected to the beginning of the next phase forming a triangle); and star (where the ends of each phase winding are connected together, forming a neutral point and the beginning of windings are connected outside). Typically, distribution transformer is connected delta at the high-voltage side and wye at the low-voltage side. Delta connection isolates the two systems with respect to some harmonics (especially third harmonic), which are not desirable in the system. A wye connection establishes a convenient neutral point for connection to the ground.

(f) *Voltage regulation*, which indicates that the transformer is capable of changing the low-voltage side voltage in order to maintain nominal voltage at customer service points. Voltage at customer service points can fluctuate as a result of either primary system voltage fluctuation or excessive voltage drop due to the high load current. To achieve this, transformers are equipped with voltage tap regulators. Those can be either no-load type, requiring disconnecting the load to change the tap, or under-load type, allowing tap changing during transformer normal load conditions. Transformer taps effectively change the transformation ratio and allow voltage regulation of ±10–15% in steps of 1.75–2.5% per tap. Transformer tap changing can be manual or automatic; however, only under-load type tap changers can operate automatically.

Busbars

Busbars (also called buses) can be found throughout the entire power system, from generation to industrial plants to electrical distribution boards. Busbars are used to carry large current and to distribute current to multiple circuits within switchgear or equipment (Fig. 2.27). Plug-in devices with circuit breakers or fusible switches may be installed and wired without de-energizing the busbars if so specified by the manufacturer.

Originally, busbars consisted of uncovered copper conductors supported on insulators, such as porcelain, mounted within a non-ventilated steel housing. This type of construction was adequate for current ratings of 225–600 A. As the use of busbars expanded and increased, loads demanded higher current ratings

Fig. 2.27 Outdoor switchgear busbar (upper conductors) with voltage transformers (Courtesy of General Electric)

and housings were ventilated to provide better cooling at higher capacities. The busbars were also covered with insulation for safety and to permit closer spacing of bars of opposite polarity in order to achieve lower reactance and voltage drop.

By utilizing conduction, current densities are achieved for totally enclosed busbars that are comparable to those previously attained with ventilated busbars. Totally enclosed busbars have the same current rating regardless of mounting position. Bus configuration may be a stack of one busbar per phase (0–800 A), whereas higher ratings will use two (3,000 A) or three stacks (5,000 A). Each stack may contain all three phases, neutral, and grounding conductors to minimize circuit reactance.

Busbars' conductors and current-carrying parts can be either copper, aluminum, or copper alloy rated for the purpose. Compared to copper, electrical grade aluminum has lower conductivity and lower mechanical strength. Generally, for equal current-carrying ability, aluminum is lighter in weight and less costly. All contact locations on current-carrying parts are plated with tin or silver to prevent oxides or insulating film from building up on the surfaces.

In distribution substations, busbars are used at both high side and low side voltages to connect different circuits and to transfer power from the power supply to multiple outcoming feeders. Feeder busbars are available for indoor and outdoor construction. Outdoor busbars are designed to operate reliably despite exposure to the weather. Available current ratings range from 600 to 5,000 A continuous current. Available short-circuit current ratings are 42,000–200,000 A, symmetrical root mean square (RMS).

Fig. 2.28 Indoor switchgear front view (Courtesy of General Electric)

Switchgear

Switchgear (Fig. 2.28) is a general term covering primary switching and interrupting devices together with its control and regulating equipment. Power switchgear includes breakers, disconnect switches, main bus conductors, interconnecting wiring, support structures with insulators, enclosures, and secondary devices for monitoring and control. Power switchgear is used throughout the entire power system, from generation to industrial plants to connect incoming power supply and distribute power to consumers. Switchgear can be of outdoor or indoor types, or a combination of both. Outdoor switchgear is typically used for voltages above 26 kV, whereas indoor switchgear is commonly for voltages below 26 kV.

Indoor switchgear can be further classified into metal-enclosed switchgear and open switchgear, which is similar to outdoor switchgear but operates at lower voltages. Metal-enclosed switchgear can be further classified into metal-clad switchgear, low-voltage breaker switchgear, and interrupter switchgear. Metal-clad switchgear is commonly used throughout the industry for distributing supply voltage service above 1,000 V.

Metal-clad switchgear can be characterized as follows:

(a) The primary voltage breakers and switches are mounted on a removable mechanism to allow for movement and proper alignment.
(b) Grounded metal barriers enclose major parts of the primary circuit, such as breakers or switches, buses, potential transformers, and control power transformers.
(c) All live parts are enclosed within grounded metal compartments. Primary circuit elements are not exposed even when the removable element is in the test, disconnected, or in the fully withdrawn position.
(d) Primary bus conductors and connections are covered with insulating material throughout by means of insulated barriers between phases and between phase and ground.

(e) Mechanical and electrical interlocking ensures proper and safe operation.
(f) Grounded metal barriers isolate all primary circuit elements from meters, protective relays, secondary control devices, and wiring. Secondary control devices are mounted of the front panel, and are usually swing type as shown in Fig. 2.28.

Switchgear ratings indicate specific operating conditions, such as ambient temperature, altitude, frequency, short-circuit current withstand and duration, overvoltage withstand and duration, etc. The rated continuous current of a switchgear assembly is the maximum current in RMS (root mean square) amperes, at rated frequency, that can be carried continuously by the primary circuit components without causing temperatures in excess of the limits specified by applicable standards.

Outcoming Feeders

A number of outcoming feeders are connected to the substation bus to carry power from the substation to points of service. Feeders can be run overhead along streets, or beneath streets, and carry power to distribution transformers at or near consumer premises. The feeders' breaker and isolator are part of the substation low-voltage switchgear and are typically the metal-clad type. When a fault occurs on the feeder, the protection will detect it and open the breaker. After detection, either automatically or manually, there may be one or more attempts to reenergize the feeder. If the fault is transient, the feeder will be reenergized and the breaker will remain closed. If the fault is permanent, the breaker will remain open and operating personnel will locate and isolate the faulted section of the feeder.

Switching Apparatus

Switching apparatus is needed to connect or disconnect elements of the power system to or from other elements of the system. Switching apparatus includes switches, fuses, circuit breakers, and service protectors.

(a) *Switches* are used for isolation, load interruption, and transferring service between different sources of supply.

Isolating switches are used to provide visible disconnect to enable safe access to the isolated equipment. These switches usually have no interrupting current rating, meaning that the circuit must be opened by other means (such as breakers). Interlocking is generally provided to prevent operation when the switch is carrying current.

Load interrupting or a load-break switch combines the functions of a disconnecting switch and a load interrupter for interrupting at rated voltage and currents not exceeding the continuous-current rating of the switch. Load-break switches are of the air- or fluid-immersed type. The interrupter switch is usually manually operated and has a "quick-make, quick-break" mechanism which functions independently of the speed-of-handle operation. These types of switches are typically used on voltages above 600 V.

For services of 600 V and below, safety circuit breakers and switches are commonly used. Safety switches are enclosed and may be fused or un-fused. This type of switch is operated by a handle outside the enclosure and is interlocked so that the enclosure cannot be opened unless the switch is open or the interlock defeater is operated.

Transfer switches can be operated automatically or manually. Automatic transfer switches are of double-throw construction and are primarily used for emergency and standby power generation systems rated at 600 V and lower. These switches are used to provide protection against normal service failures.

(b) *Fuses* are used as an over-current-protective device with a circuit-opening fusible link that is heated and severed as over-current passes through it. Fuses are available in a wide range of voltage, current, and interrupting ratings, current-limiting types, and for indoor and outdoor applications. Fuses perform the same function as circuit breakers, and there is no general rule for using one versus the other. The decision to use a fuse or circuit breaker is usually based on the particular application, and factors such as the current interrupting requirement, coordination with adjacent protection devices, space requirements, capital and maintenance costs, automatic switching, etc.

(c) *Circuit breakers* (Fig. 2.29) are devices designed to open and close a circuit either automatically or manually. When applied within its rating, an automatic circuit breaker must be capable of opening a circuit automatically on a predetermined overload of current without damaging itself or adjacent elements. Circuit breakers are required to operate infrequently, although some classes of circuit breakers are suitable for more frequent operation. The interrupting and momentary ratings of a circuit breaker must be equal to or greater than the available system short-circuit currents.

Circuit breakers are available for the entire system voltage range, and may be as furnished single-, double-, triple-, or four-pole, and arranged for indoor or outside use. Sulfur hexafluoride (SF_6) gas-insulated circuit breakers are available for medium and high voltages, such as gas-insulated substations.

When a current is interrupted, an arc is generated. This arc must be contained, cooled, and extinguished in a controlled way so that the gap between the contacts can again withstand the voltage in the circuit. Circuit breakers can use vacuum, air, insulating gas, or oil as the medium in which the arc forms. Different techniques are used to extinguish the arc, including:

- Lengthening the arc
- Intensive cooling (in jet chambers)
- Division into partial arcs
- Zero point quenching (contacts open at the zero current time crossing of the AC waveform, effectively breaking no-load current at the time of opening)
- Connecting capacitors in parallel with contacts in DC circuits

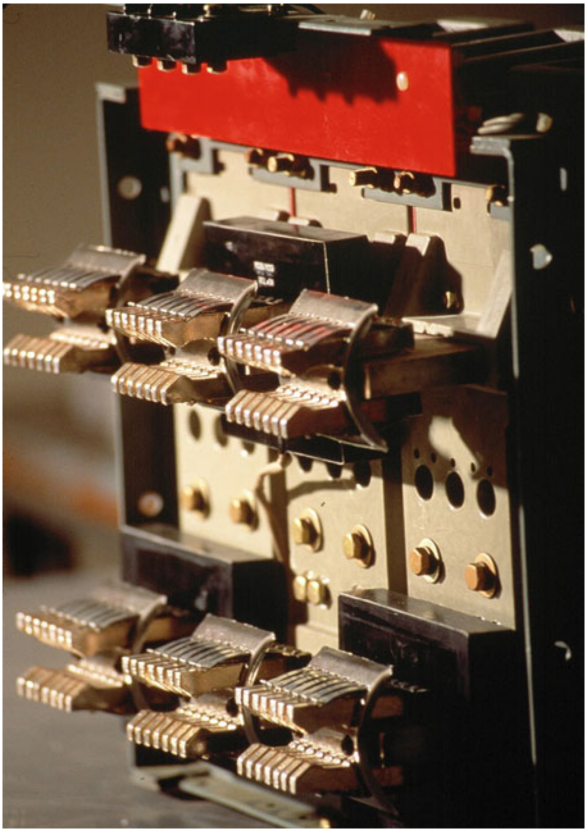


Fig. 2.29 Breaker of indoor switchgear, rear "bus" side (Courtesy of General Electric)

Traditionally, oil circuit breakers (Fig. 2.30) were used in the power industry, which use oil as a media to extinguish the arc and rely upon vaporization of some of the oil to blast a jet of oil through the arc.

Gas (usually sulfur hexafluoride) circuit breakers sometimes stretch the arc using a magnetic field, and then rely upon the dielectric strength of the sulfur hexafluoride to quench the stretched arc.

Vacuum circuit breakers have minimal arcing (as there is nothing to ionize other than the contact material), so the arc quenches when it is stretched by a very small amount (<2–3 mm). Vacuum circuit breakers are frequently used in modern medium-voltage switchgear up to 35 kV.

Air blast circuit breakers may use compressed air to blow out the arc, or alternatively, the contacts are rapidly swung into a small sealed chamber, where the escaping displaced air blows out the arc.

Circuit breakers are usually able to terminate all current very quickly: Typically the arc is extinguished between 30 and 150 ms after the mechanism has tripped, depending upon age and construction of the device.

Indoor circuit breakers are rated to carry 1–3 kA current continuously, and interrupting 8–40 kA short-circuit current at rated voltage.

Fig. 2.30 Outdoor medium-voltage oil-immersed circuit breaker (Courtesy of General Electric)

Surge Voltage Protection

Transient overvoltages are due to natural and inherent characteristics of power systems. Overvoltages may be caused by lightning or by a sudden change of system conditions (such as switching operations, faults, load rejection, etc.), or both. Generally, the overvoltage types can be classified as lightning generated and as switching generated. The magnitude of overvoltages can be above maximum permissible levels, and therefore needs to be reduced and protected against to avoid damage to equipment and undesirable system performance.

The occurrence of abnormal applied overvoltage stresses, either short term or sustained steady state, contributes to premature insulation failure. Large amounts of current may be driven through the faulted channel, producing large amounts of heat. Failure to suppress overvoltage quickly and effectively or interrupt high short-circuit current can cause massive damage of insulation in large parts of the power system, leading to lengthy repairs.

The appropriate application of surge-protective devices will lessen the magnitude and duration of voltage surges seen by the protected equipment. The problem is complicated by the fact that insulation failure results from impressed overvoltages, and because of the aggregate duration of repeated instances of overvoltages.

Surge arresters have been used in power systems to protect insulation from overvoltages. Historically, the evolution of surge arrester material technology has produced various arrester designs, starting with the valve-type arrester, which has been used almost exclusively on power system protection for decades. The active element (i.e., valve element) in these arresters is a nonlinear resistor that exhibits relatively high resistance (megaohms) at system operating voltages, and a much lower resistance (ohms) at fast rate-of-rise surge voltages.

In the mid-1970s, arresters with metal-oxide valve elements were introduced. Metal-oxide arresters have valve elements (also of sintered ceramic-like material) of a much greater nonlinearity than silicon carbide arresters, and series gaps are no longer required. The metal-oxide designs offer improved protective characteristics and improvement in various other characteristics compared to silicon carbide designs. As a result, metal-oxide arresters have replaced gapped silicon carbide arresters in new installations.

In the mid-1980s, polymer housings began to replace porcelain housings on metal-oxide surge arresters offered by some manufacturers. The polymer housings are made of either EPDM (ethylene propylene diene monomer [M-class] rubber) or silicone rubber. Distribution arrester housings were first made with polymer, and later expanded into the intermediate and some station class ratings. Polymer housing material reduces the risk of injuries and equipment damage due to surge arrester failures.

Arresters have a dual fundamental-frequency (RMS) voltage rating (i.e., duty-cycle voltage rating), and a corresponding maximum continuous operating voltage rating. Duty-cycle voltage is defined as the designated maximum permissible voltage between the terminals at which an arrester is designed to perform.

Grounding

Grounding is divided into two categories: power system grounding and equipment grounding.

Power system grounding means that at some location in the system there are intentional electric connections between the electric system phase conductors and ground (earth). System grounding is needed to control overvoltages and to provide a path for ground-current flow in order to facilitate sensitive ground-fault protection based on detection of ground-current flow. System grounding can be as follows:

- Solidly grounded
- Ungrounded
- Resistance grounded

Each grounding arrangement has advantages and disadvantages, with choices driven by local and global standards and practices, and engineering judgment.

Solidly grounded systems are arranged such that circuit protective devices will detect a faulted circuit and isolate it from the system regardless of the type of fault. All transmission and most sub-transmission systems are solidly grounded for system stability purposes. Low-voltage service levels of 120–480 V four-wire systems must also be solidly grounded for safety of life. Solid grounding is achieved by connecting the neutral of the wye-connected winding of the power transformer to the ground.

Where service continuity is required, such as for a continuously operating process, the resistance grounded power system can be used. With this type of grounding, the intention is that any contact between one phase conductor and a ground will not cause the phase over-current protective device to operate. Resistance grounding is typically used from 480 V to 15 kV for three-wire systems. Resistance grounding is achieved by connecting the neutral of the wye-connected winding of the power transformer to the ground through the resistor, or by employing special grounding transformers.

The operating advantage of an ungrounded system is the ability to continue operations during a single phase-to-ground fault, which, if sustained, will not result in an automatic trip of the circuit by protection. Ungrounded systems are usually employed at the distribution level and are originated from delta-connected power transformers.

Equipment grounding refers to the system of electric conductors (grounding conductor and ground buses) by which all non-current-carrying metallic structures within an industrial plant are interconnected and grounded. The main purposes of equipment grounding are:

- To maintain low potential difference between metallic structures or parts, minimizing the possibility of electric shocks to personnel in the area
- To contribute to adequate protective device performance of the electric system, and safety of personnel and equipment
- To avoid fires from volatile materials and the ignition of gases in combustible atmospheres by providing an effective electric conductor system for the flow of ground-fault currents and lightning and static discharges to eliminate arcing and other thermal distress in electrical equipment

Substation grounding systems are thoroughly engineered. In an electrical substation, a ground (earth) mat is a mesh of metal rods connected together with conductive material and installed beneath the earth surface. It is designed to prevent dangerous ground potential from rising at a place where personnel would be located when operating switches or other apparatus. It is bonded to the local supporting metal structure and to the switchgear so that the operator will not be exposed to a high differential voltage due to a fault in the substation.

Power Supply Quality

The quality of electrical power may be described as a set of values or parameters, such as:

- Continuity of service

Fig. 2.31 Capacitor Bank (Courtesy of General Electric)

- Variation in voltage magnitude
- Transient voltages and currents
- Harmonic content in the supply voltages

Continuity of service is achieved by proper design, timely maintenance of equipment, reliability of all substation components, and proper operating procedures. Recently, remote monitoring and control have greatly improved the power supply continuity.

When the voltage at the terminals of utilization equipment deviates from the value on the nameplate of the equipment, the performance and the operating life of the equipment are affected. Some pieces of equipment are very sensitive to voltage variations (e.g., motors). Due to voltage drop down the supply line, voltage at the service point may be much lower compared with the voltage at substation. Abnormally low voltage occurs at the end of long circuits. Abnormally high voltage occurs at the beginning of circuits close to the source of supply, especially under lightly loaded conditions such as at night and during weekends. Voltage regulators are used at substations to improve the voltage level supplied from the distribution station. This is achieved by a tap changer mounted in the transformer and an automatic voltage regulator that senses voltage and voltage drop due to load current to increase or decrease voltage at the substation.

If the load power factor is low, capacitor banks (Fig. 2.31) may be installed at the substation to improve the power factor and reduce voltage drop. Capacitor banks are especially beneficial at substations near industrial customers where reactive power is needed for operation of motors.

Transients in voltages and currents may be caused by several factors, such as large motor stating, fault in the sub-transmission or distribution system, lightning, welding equipment and arc furnace operation, turning on or off large loads, etc. Lighting equipment output is sensitive to applied voltage, and people are sensitive to sudden illumination changes. A voltage change of 0.25–0.5% will cause a noticeable reduction in the light output of an incandescent lamp. Events causing such voltage effects are called flicker (fast change of the supply voltage), and voltage sags (depressed voltage for a noticeable time). Both flicker and sags have operational limits and are governed by industry and local standards.

Voltage and current on the ideal AC power system have pure single frequency sine wave shapes. Power systems have some distortion because an increasing number of loads require current that is not a pure sine wave. Single- and three-phase rectifiers, adjustable speed drives, arc furnaces, computers, and fluorescent lights are good examples. Capacitor failure, premature transformer failure, neutral overloads, excessive motor heating, relay misoperation, and other problems are possible when harmonics are not properly controlled.

Harmonics content is governed by appropriate industry and local standards, which also provide recommendations for control of harmonics in power systems.

Substation Design Considerations

Distribution substation design is a combination of reliability and quality of the power supply, safety, economics, maintainability, simplicity of operation, and functionality.

Safety of life and preservation of property are the two most important factors in the design of the substation. Codes must be followed and recommended practices or standards should be followed in the selection and application of material and equipment. Following are the operating and design limits that should be considered in order to provide safe working conditions:

- Interrupting devices must be able to function safely and properly under the most severe duty to which they may be exposed.
- Accidental contact with energized conductors should be eliminated by means of enclosing the conductors, installing protective barriers, and interlocking.
- The substation should be designed so that maintenance work on circuits and equipment can be accomplished with these circuits and equipment de-energized and grounded.
- Warning signs should be installed on electric equipment accessible to both qualified and unqualified personnel, on fences surrounding electric equipment, on access doors to electrical rooms, and on conduits or cables above 600 V in areas that include other equipment.
- An adequate grounding system must be installed.

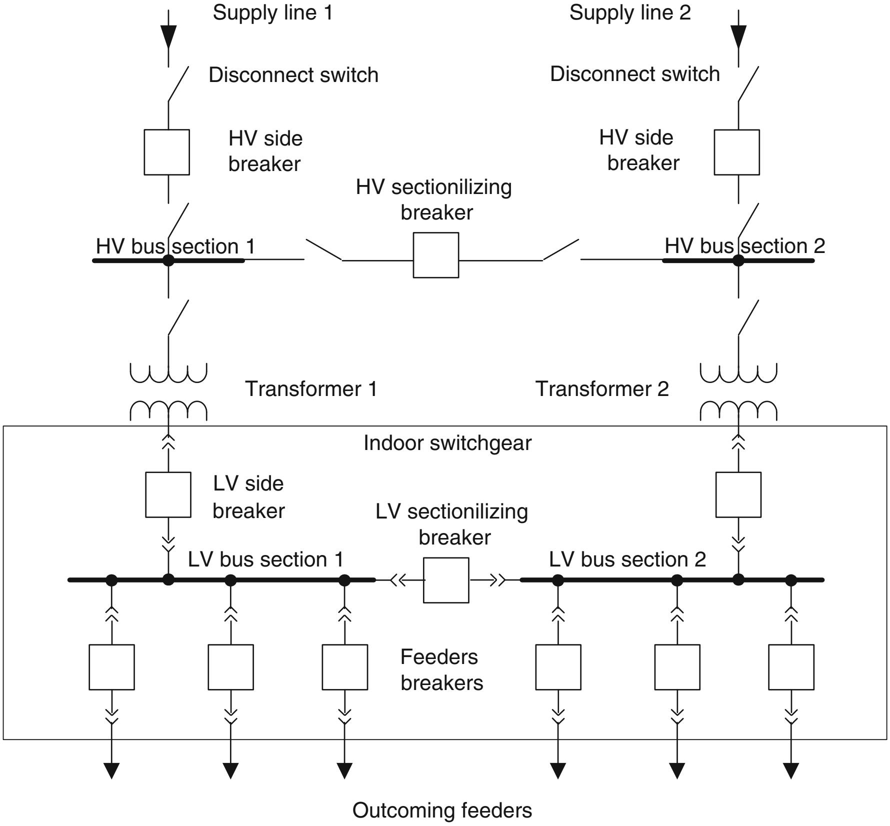


Fig. 2.32 Example one-line diagram of distribution substation with two transformers and two supply lines

- Emergency lights should be provided where necessary to protect against sudden lighting failure.
- Operating and maintenance personnel should be provided with complete operating and maintenance instructions, including wiring diagrams, equipment ratings, and protective device settings.

A variety of basic circuit arrangements are available for distribution substations. Selection of the best system or combination of systems will depend upon the needs of the power supply process. In general, system costs increase with system reliability if component quality is equal. Maximum reliability per unit investment can be achieved by using properly applied and well-designed components.

Figure 2.32 provides an example of the distribution substation one-line diagram with two transformers, two supply lines, and two sections at both the high-voltage (HV) side and low-voltage (LV) sides, with sectionalizing breakers at both HV and LV voltages. Such an arrangement provides redundancy and reliability in case of any component failure by transferring the power supply from one section to another. Additionally, any component of the substation can be taken out of service for maintenance.

If the substation is designed to supply a manufacturing plant, continuity of service may be critical. Some plants can tolerate interruptions while others require the highest degree of service continuity. The system should always be designed to isolate faults with a minimum disturbance to the system, and should have features to provide the maximum dependability consistent with the plant requirements and justifiable cost. The majority of utilities today supply energy to medium and large industrial customers directly at 34.5, 69, 115, 138, 161, and 230 kV using dedicated substations. Small industrial complexes may receive power at voltages as low as 4 kV.

Poor voltage regulation is harmful to the life and operation of electrical equipment. Voltage at the utilization equipment must be maintained within equipment tolerance limits under all load conditions, or equipment must be selected to operate safely and efficiently within the voltage limits. Load-flow studies and motor-starting calculations are used to verify voltage regulation.

Substation Standardization

Standards, recommended practices, and guides are used extensively in communicating requirements for design, installation, operation, and maintenance of substations. Standards establish specific definitions of electrical terms, methods of measurement and test procedures, and dimensions and ratings of equipment. Recommended practices suggest methods of accomplishing an objective for specific conditions. Guides specify the factors that should be considered in accomplishing a specific objective. All are grouped together as standards documents.

Standards are used to establish a small number agreed to by the substation community of alternative solutions from a range of possible solutions. This allows purchasers to select a specific standard solution knowing that multiple vendors will be prepared to supply that standard, and that different vendor's produces will be able to interoperate with each other. Conversely, this allows vendors to prepare a small number of solutions knowing that a large number of customers will be specifying those solutions. Expensive and trouble-prone custom "one-of-a-kind" design and manufacturing can be avoided. For example, out of the almost infinite range of voltage ratings for 3-wire 60 Hz distribution substation low side equipment, NEMA C84.1 standardizes only seven: 2,400, 4,160, 4,800, 6,900, 13,800, 23,000, and 34,500 V. Considerable experience and expertise goes into the creation and maintenance of standards, providing a high degree of confidence that solutions implemented according to a standard will perform as expected. Standards also allow purchasers to concisely and comprehensively state their requirements, and allow vendors to concisely and comprehensively state their products' performance.

There are several bodies publishing standards relevant to substations. Representative of these are the following:

The Institute of Electrical and Electronics Engineers (IEEE) is a nonprofit, transnational professional association having 38 societies, of which the Power and Energy Society (PES) is "involved in the planning, research, development, construction, installation, and operation of equipment and systems for the safe, reliable, and economic generation, transmission, distribution, measurement, and control of electric energy." PES includes several committees devoted to various aspects of substations that publish a large number of standards applicable to substations. For more information, visit www.ieee-pes.org.

The National Electrical Manufacturers Association (NEMA) is a trade association of the electrical manufacturing industry that manufactures products used in the generation, transmission and distribution, control, and end-use of electricity. NEMA provides a forum for the development of technical standards that are in the best interests of the industry and users; advocacy of industry policies on legislative and regulatory matters; and collection, analysis, and dissemination of industry data. For more information, visit www.nema.org.

American National Standards Institute (ANSI) oversees the creation, promulgation, and use of thousands of norms and guidelines that directly impact businesses in nearly every sector, including energy distribution. ANSI is also actively engaged in accrediting programs that assess conformance to standards – including globally recognized cross-sector programs such as the ISO 9000 (quality) and ISO 14000 (environmental) management systems. For more information, see www.ansi.org.

National Fire Protection Association (NFPA) is an international nonprofit organization established in 1896 to reduce the worldwide burden of fire and other hazards on the quality of life by providing and advocating consensus codes and standards, research, training, and education. NFPA develops, publishes, and disseminates more than 300 consensus codes and standards intended to minimize the possibility and effects of fire and other risks. Of particular interest to substations is the National Electrical Code (NEC). For more information, see www.nfpa.org.

International Electrotechnical Commission (IEC) technical committee is an organization for the preparation and publication of International Standards for all electrical, electronic, and related technologies. These are known collectively as "electrotechnology." IEC provides a platform to companies, industries, and governments for meeting, discussing, and developing the International Standards they require. All IEC International Standards are fully consensus based and represent the needs of key stakeholders of every nation participating in IEC work. Every member country, no matter how large or small, has one vote and a say in what goes into an IEC International Standard. For more information, see www.iec.ch.

International Organization for Standardization (ISO) is a nongovernmental organization that forms a bridge between the public and private sectors. Many of its member institutes are part of the governmental structure of their countries, or are mandated by their government while other members have their roots uniquely in the private sector, having been set up by national partnerships of industry associations. ISO enables a consensus to be reached on solutions that meet both the requirements of business and the broader needs of society. For more information, see www.iso.org.

International Telecommunication Union (ITU) is the United Nations' agency for information and communication technology issues, and the global focal point for governments and the private sector in developing networks and services. For 145 years, ITU has coordinated the shared global use of the radio spectrum, promoted international cooperation in assigning satellite orbits, worked to improve telecommunication infrastructure in the developing world, established the worldwide standards that foster seamless interconnection of a vast range of communications systems, and addressed the global challenges of our times, such as mitigating climate change and strengthening cyber security. For more information, see www.iut.int.

Substation Physical Appearance

It is desirable to locate distribution substations as near as possible to the load center of its service area, though this requirement is often difficult to satisfy. Locations that are perfect from engineering and cost points of view are sometimes prohibited due to physical, electrical, neighboring, or aesthetic considerations. Given the required high- and low-voltage requirements and the required power capacity, a low-cost aboveground design will satisfy power supply needs. However, an aboveground design requires overhead sub-transmission line structures (Fig. 2.33), which are often undesirable structures for neighborhoods. Therefore, incoming lines are often underground cables, and the entire substation is designed to be as unobtrusive as possible.

Underground cables are more costly than overhead lines for the same voltage and capacity. Installation of underground cables in urban areas is also often inconvenient and potentially hazardous.

Local conditions or system-wide policy may require landscaping at a substation site or for housing the substation within a building. A fence with warning signs or other protective enclosures is typically provided to keep unauthorized persons from coming in close proximity of the high-voltage lines and substation equipment. Alarm systems and video surveillance are becoming normal practices for monitoring and preventing intrusion by unauthorized persons.

Protection and Automation

The purpose of protection in distribution substations is to isolate faulted power system elements, such as feeders and transformers, from sources of electrical supply in order to:

Fig. 2.33 Distribution substation view (Courtesy of General Electric)

- Prevent damage to un-faulted equipment that might otherwise result from sustained fault-level currents and/or voltages
- Reduce the probability and degree of harm to the general public, utility personnel, and property
- Reduce the amount of damage the faulted element sustains, thus containing repair costs, service interruption duration, and impact on the environment
- Clear transient faults and restore service

To accomplish this, protection devices must be able to rapidly determine that a fault has occurred, determine which system element or which section of the system has faulted, and to open the circuit breakers and switches that will disconnect the faulted element. To do this reliably, means must be provided to clear faults even in the event of a single failure in the protection system.

Substation automation facilities complement protection at distribution substations. In the past, automation at distribution substations was limited to automatic tap changer control and capacitor auto-switching to regulate voltage. Automation and communication facilities in modern distribution substations provide visibility to the system operator of the state of the substation, allowing rapid identification of the source and cause of interruptions and other troubles, and providing the ability to dispatch repair personnel quickly to the correct location and with the necessary equipment and spares to effect a repair. In these modern distribution substations, automation facilities often provide operators with the ability to remotely open and close breakers and switches, allowing power rerouting to restore service.

The principle by which protection operates depends to a large degree on the element covered by the protection. Common element types are as follows.

Incoming Sub-transmission Supply Line Protection at Distribution Substations

In the past, distribution substations supplied only loads; there was little if any distributed generation. With this arrangement, faults on the incoming sub-transmission supply line do not result in energy flowing out of the distribution substation and into the supply line (i.e., backfeed). In that event, opening of the distribution substation end of the supply line is not necessary to isolate supply line faults; opening of the source end by protection located there is all that is necessary.

Recently, distributed generation from windmills, bio-digesters, mini-hydraulics, and photovoltaic sources has been increasing dramatically, in some cases to the point where the contribution to the supply line faults and must be interrupted to extinguish the fault. Various protection technologies exist to detect such faults, including reverse flow, distance, and current differential.

Reverse flow protection detects the reversal from the normal direction of power and/or current flow. This type of protection is only suitable for cases where the amount of distributed generation in relation to the amount of load is small enough that under normal un-faulted conditions the flow from the supply line is always into the distribution substation. Reverse flow occurs when a supply line fault causes voltage depression to the point where load current essentially disappears, yet the distributed generators continue to source current.

Distance protection estimates the impedance of the supply line between the distribution substation and a fault on the supply line. Supply lines typically have a constant amount of impedance per unit distance (e.g., per kilometer), so the impedance seen at the distribution substation is larger for a fault beyond the end of the supply line than for a fault on the supply line. Distance protection thus can usually discriminate between these two faults, and avoid unnecessary tripping for faults beyond the supply line. To a first approximation, impedance is simply the voltage divided by the current.

Current differential protection is based on the fact that the algebraic sum of all supply line terminal currents is equal to the supply line fault current, if any. Current resulting from external faults and from load flowing into the supply line is canceled as it flows out. Charging current is typically negligible at sub-transmission voltage levels.

With each of these three methods, current transformers (CTs) are needed to measure supply line current, and except for current differential, voltage transformers (VTs) are needed to measure the voltage at the distribution substation. With current differential, a communications channel to the other end(s) of the supply line is needed. A relay (also known as an IED) is needed to detect the supply line fault and discriminate it from other conditions such as faults on other elements. Also, a circuit breaker or circuit switcher is needed to interrupt the supply line connection on command from the relay.

Fig. 2.34 Modern digital transformer protection relay (Courtesy of General Electric)

Distribution Substation Transformer Protection

In distribution substations with relatively small delta/wye transformers (typically less than 10 MVA), transformer protection often consists of simple fusing. A power fault in the transformer or on the low side bus typically produces a large current in the high side terminals that melts the fusible links, interrupting the fault. Internal turn-to-turn winding faults that produce only small terminal fault currents are allowed to burn until the fault evolves into a fault with current large enough to operate the fuses. This is acceptable because there is little or no difference in the commercial value of faulted transformers, and because small transformers on which fuses are used are less costly.

On larger (and more expensive) transformers, through-current restrained differential relays (Fig. 2.34) are most often employed. These protections require CTs measuring all current paths in and out of the transformer. Most often, the CTs are mounted on the high side terminals of the transformer and on the breaker(s) that directly connect to the low side terminals. Where there is no breaker between the transformer and the low side bus, the bus is also covered. The operating principle of transformer current differential protection is based on the incoming high side current under normal and under external fault conditions approximately equaling the sum of the outgoing low side currents after adjusting for the transformer's transformation ratio and internal connection (e.g., delta/wye). During internal fault conditions, there is a large inequality.

Invariably, there is actually some difference between these (even in a healthy transformer) that is a small but constant percentage of the current flowing through the transformer. An on-load tap changer is an example of what can cause such a difference. For large through-currents, such as occurring during external low side faults, the difference is substantial, so the relay employs through-current restraint. The differential operating threshold is made dynamic by including in the trip threshold a percentage of the measured through-current.

Another problem with transformer differential protection is that when the transformer itself is saturated, which usually occurs on energization, relatively large currents flow through the excitation impedance, which appear to the protection as differential current with no through-current. Energization current, however, contains a large harmonic component. Relays therefore monitor for the presence of such harmonics, most often the second harmonic, and when found block the differential element.

When a transformer fault is detected, the transformer is isolated by opening its high side connection. Where there are fuses, the fuses perform the interruption. Where there is a high side breaker or circuit switcher, they are tripped. Otherwise, a trip signal is sent to trip the remote end of the supply line. This signal may be via radio, optical fiber, or metallic pair, or may be the closing a switch that grounds one phase of the supply line causing the remote end to see and trip as for a supply line fault. Where there are distributed generators on the distribution system, the distributed generators or the distribution substation's low side breakers must be opened as well. Opening of low side breakers is often done even when there are no distributed generators.

Distribution Substation Bus Protection

When fuses protect a distribution substation transformer and there is no transformer low side breaker and the differential uses feeder breaker CTs, the transformer protection covers the low side bus as well as the transformer.

Where a separate bus protection is used, there are several alternatives for detecting bus faults, including low impedance current differential, high impedance differential, and zone-interlocked schemes.

Low impedance bus differential with through-current restraint operates on the same basic principle as transformer differential protection. Buses have no significant energization current, so harmonic blocking is not implemented. Also there is no need to adjust for transformer connection. However, there are typically many more feeders to measure than in transformer differential applications, so a relay designed for bus protection is required. Low impedance bus differential protections without through-current restraint have been deployed, but often have trouble with CT saturation, causing unnecessary tripping.

High impedance bus differential protections include a simple over-current relay with a large stabilizing resister connected in series. The relay current is from the parallel connection of the secondary windings of CTs measuring all bus connections. The CTs should be identical in type and ratio. With no fault, the current flowing into the bus is balanced by the current flowing out of the bus (a pattern that is matched in the CT secondary circuit), and thus little or no current flows through the over-current relay. The stabilizing resistor tends to prevent large external fault currents from saturating the CT of the faulted feeder and producing erroneous differential current.

Zone-interlocked schemes (also known as bus-blocking schemes) employ an over-current relay measuring infeed current from the main transformer. On detecting fault current, this over-current relay trips the bus unless one of the feeder protections sees a feeder fault and sends a blocking signal. Bus tripping is delayed by a short time to ensure that the feeder protections have sufficient time to detect and block for feeder faults.

No matter the detection method used, when a bus fault is detected, the fault current coming from the main transformer must be interrupted. Where there is a transformer low side breaker, it is opened. Otherwise, the transformer high side is opened using one or more of the methods described in the transformer protection section. Where there are distributed generators on the distribution system, the distributed generators or the distribution substation's low side breakers or circuit switchers must be opened as well. Opening of low side breakers is often done even when there are no distributed generators.

Distribution Feeder Protection

Distribution feeder protection at distribution substations is most often instantaneous and timed over-current functionality. Very often, these functions are implemented within a recloser, which is essentially a circuit breaker packaged with a mechanism that repeatedly trips when current exceeds a set threshold, and then recloses or locks out after a series of set delays. Alternatively, an electronic relay with instantaneous and inverse time over-current features is used.

Distribution feeders (Fig. 2.35) typically have fuses along its length and/or on lateral sections intended to separate a faulted section, allowing the rest to be supplied pending repair. Feeder protections usually implement either a fuse-saving or a trip-saving scheme.

Aerial feeders are prone to transient faults, faults that due to lightning or winding-induced swaying (the technical term is "galloping") disappear when the fault current is interrupted and the arc extinguished. A fuse-saving scheme is often used on these. Such a scheme has in normal conditions an instantaneous over-current element that trips the feeder breaker immediately upon detecting a fault. High speed tripping is used to prevent any fuses between the substation and the fault from melting. After the fault current has been interrupted, the instantaneous element is blocked, an inverse time element is enabled, and the feeder breaker reclosed. For transient faults, on reclosing, the fault will have disappeared and supply to all customers is restored. After a short delay of typically a few seconds, the scheme is reset and the instantaneous element placed back in service. For permanent faults, on reclosing, fault current will again flow, and the inverse time relay will start to operate. The inverse time relay is set to coordinate with the fuses such that if there is a fuse between the substation and the fault, the fuse will operate, interrupting customers on the section it supplies, but leaving all others energized. If the fault is located before any fuse, the inverse time relay will time out and trip the entire feeder.

Underground cable feeders rarely have transient faults; cable faults are almost always permanent. A trip-saving scheme is often used on these. Such a scheme has in normal conditions an inverse time element that trips the feeder only after sufficient time for any fuse between the substation and the fault to operate, interrupting customers on the section it supplies, but leaving all others energized.

Fig. 2.35 Modern digital feeder protection relay (Courtesy of General Electric)

If the fault is located before any fuse, the inverse time relay will time out and trip the entire feeder. Following the feeder trip, an automatic reclose with instantaneous tripping may be attempted to restore service in cases of a fuse having melted but having been unable to interrupt fault current prior to the first trip.

Occasionally, distribution substation feeder protection includes distance supervision to prevent unnecessary tripping feeder tripping for faults on the low side of large distribution transformers near the substation. Such faults should instead be cleared at the distribution transformer location so that other customers on the feeder are not interrupted.

High Penetration of Distributed Generation and Its Impact on System Design and Operations

High penetration of distributed generation presents significant challenges to design and engineering practices as well as to the reliable operation of the electrical distribution system. The large-scale implementation of distributed energy resources (DER) on system design, performance, and reliable operation requires an integrated approach focused on interoperability, adaptability, and scalability.

Vision for Modern Utilities

Centralized Versus Distributed Generation

The bulk of electric power used worldwide is produced at central power plants, most of which utilize large fossil fuel combustion, hydro or nuclear reactors. A majority of these central stations have an output between 30 MW (industrial plant) and 1,700 MW. This makes them relatively large in terms of both physical size and facility requirements as compared with DG alternatives. In contrast, DG is:

- Installed at various locations (closer to the load) throughout the power system
- Not centrally dispatched (although the development of "virtual" power plants, where many decentralized DG units operate as one single unit, may be an exception to this definition)
- Defined by power rating in a wide range from a few kW to tens of MW (in some countries MW limitation is defined by standards, e.g., US, IEEE 1547 defines DG up to 10 MW – either as a single unit or aggregate capacity)
- Connected to the distribution/medium-voltage network – which generally refers to the part of the network that has an operating voltage of 600 V up to 110 kV (depends on the utility/country)

The ownership of the DG is not a factor as to whether a power generator is classified as DG. DG can be owned or operated by electric customers, energy service companies, independent power producers (IPP), or utilities.

The main reasons why central, rather than distributed, generation still dominates current electricity production include economy of scale, fuel cost and availability, and lifetime. Increasing the size of a production unit decreases the cost per MW; however, the advantage of economy of scale is decreasing – technological advances in fuel conversion have improved the economy of small units. Fuel cost and availability is still another reason to keep building large power plants. Additionally, with a lifetime of 25–50 years, large power plants will continue to remain the prime source of electricity for many years to come [1].

The benefits of distributed generation include: higher efficiency; improved security of supply; improved demand-response capabilities; avoidance of overcapacity; better peak load management; reduction of grid losses; network infrastructure cost deferral (CAPEX deferral); power quality support; improved reliability; and environmental and aesthetic concerns (offers a wide range of alternatives to traditional power system design). DG offers extraordinary value because it provides a flexible range of combinations between cost and reliability. In addition, DG may eventually become a more desirable generation asset because it is "closer" to the customer and is more economical than central station generation and its associated transmission infrastructure [2]. The disadvantages of DG are ownership and operation, fuel delivery (machine-based DG, remote locations), cost of connection, dispatchability, and controllability (wind and solar).

Development of "Smart Grid"

In recent years, there has been rapidly growing interest in what is called "smart grid – digitized grid – grid of the future." The concept of smart grids has many definitions and interpretations dependent on the specific country, region, and industry stakeholder's drivers and desirable outcomes and benefits.

The Smart Grids European Technology Platform (which is comprised of European stakeholders, including the research community) 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, in order to efficiently deliver sustainable, economic and secure electricity supply" [1].

In North America, the two dominant definitions of the smart grid come from the Department of Energy (DOE) and the Electric Power Research Institute (EPRI).

- *US DOE:* "Grid 2030 envisions a fully automated power delivery network that monitors and controls every customer and node, ensuring two-way flow of information and electricity between the power plant and the appliance, and all points in between" [2].
- *EPRI:* "The term 'Smart Grid' refers to a modernization of the electricity delivery system so it monitors, protects, and automatically optimizes the operation of its interconnected elements — from the central and distributed generator through the high-voltage network and distribution system, to industrial users and building automation systems, to energy storage installations and to end-use consumers and their thermostats, electric vehicles, appliances, and other household devices" [3].

Beyond a specific, stakeholder-driven definition, smart grids should refer to the entire power grid from generation through transmission and distribution infrastructure all the way to a wide array of electricity consumers (Fig. 2.36).

Effective deployment of smart grid technologies requires well-defined and quantified benefits. These benefits can be quantified in the areas of technical and business performance, environmental goals, security of electricity supply, and macro-economic growth and business sustainability development. One of the key components to effectively enable full-value realization is technology – the wide range of technical functionalities and capabilities deployed and integrated as one cohesive end-to-end solution supported by an approach focused on scalability, interoperability, and adaptability. Smart grid technologies can be broadly captured under the following areas:

- *Low Carbon:* For example, large-scale renewable generation, distributed energy resources (DER), electric vehicles (EV), and carbon capture and sequestration (CCS).
- *Grid Performance:* For example, advanced distribution and substation automation (self-healing); wide-area adaptive protection schemes (special protection schemes); wide-area monitoring and control systems (power management unit [PMU]-based situational awareness); asset performance optimization and

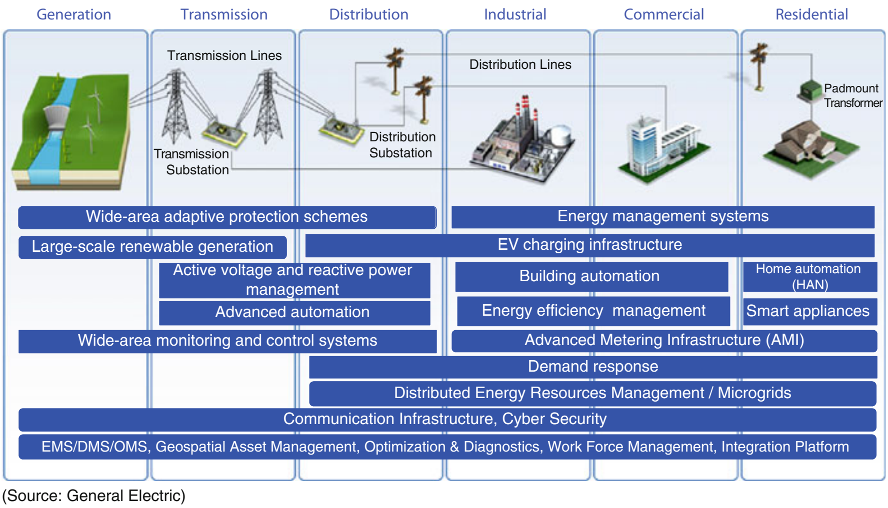


Fig. 2.36 Smart Grid Technologies span across the entire electric grid (Source: General Electric)

conditioning (condition based monitoring); dynamic rating; advanced power electronics (e.g., flexible AC transmission system (FACTS), intelligent inverters, etc.), high temperature superconducting (HTS), and many others.

- *Grid-Enhanced Applications:* For example, distribution management systems (DMS); energy management systems (EMS); outage management systems (OMS); demand response (DR); advanced applications to enable active voltage and reactive power management (integrated voltage/VAR control (IVVC), coordinated voltage/VAR control (CVVC)); advanced analytics to support operational, non-operational and BI decision making; distributed energy resource management; microgrid and virtual power plant (VPP); work force management; geospatial asset management (geographic information system (GIS)); key performance indicator (KPI) dashboards and advanced visualization; and many others.
- *Customer:* For example, advanced metering infrastructure (AMI); home/building automation (home automation network (HAN)); energy management systems and display portals; electric vehicle (EV) charging stations; smart appliances, and many others.
- *Cyber Security and Data Privacy*
- *Communication and Integration Infrastructure*

Distributed Generation Technology Landscape

Common types of distributed generation include:

- Non-renewable generation:

  - Combustion turbine generators
  - Micro-turbines
  - Internal combustion
  - Small steam turbine units

- Renewable generation:

  - Low/high temperature fuel cells (e.g., alkaline fuel cell (AFC), molten carbonate fuel cell (MCFC), phosphoric acid fuel cell (PAFC), polymer electrolyte membrane fuel cell (PEMFC), solid oxide fuel cell (SOFC), direct methanol fuel cell (DMFC))
  - Photovoltaic (PV) (mono-, multicrystalline)
  - Concentrated PV (CPV)
  - Thin-film solar
  - Solar thermal
  - Hydro-electric (e.g., run-of-river)
  - Wind/mini-wind turbines
  - Tidal/wave
  - Ocean thermal energy conversion (OTEC) (e.g., land-, shelf-, floating-based plants, open, close, and hybrid cycles)
  - Energy storage (in the dispatch mode operations)

Each of these technologies is characterized by different electric efficiency, performance, installation footprint, and capital and operational costs.

Demand-Response Design and Operational Challenges

Demand-response (DR) interconnection engineering and engineering details depend on the specific installation size (kW vs. MW); however, the overall components of the installation should include the following:

- DG prime mover (or prime energy source) and its power converter
- Interface/step-up transformer
- Grounding (when needed – grounding type depends on utility-specific system requirements)
- Microprocessor protective relays for:

  - Three-, single-phase fault detection and DG overload (50, 51, 51V, 51N, 59N, 27N, 67)
  - Islanding and abnormal system conditions detection (81o/u, 81R, 27, 59)
  - Voltage and current unbalances detection (46, 47)
  - Undesirable reverse power detection (32)
  - Machine-based DG synchronization (25)

- Disconnect switches and/or switchgear(s)

Table 2.3 DG interconnection requirements of utilities

Requirements	DG less than 10 kW	DG 10–100 kW	DG 100–1,000 kW	DG $>$ 1,000 kW or $>$20% feeder load
Disconnect switch	Yes	Yes	Yes	Yes
Protective relays: islanding prevention and synchronization	Yes	Yes	Yes	Yes
Other protective relays (e.g., unbalance)	Optional	Optional	Yes	Yes
Dedicated transformer	Optional	Optional	Yes	Yes
Grounding impedance (due to ground fault contribution current)	No	No	Optional	Often
Special monitoring and control requirements	No	Optional	Yes	Yes
Telecommunication and transfer trip	No	Optional	Optional	Yes

- Metering, control, and data logging equipment
- Communication link(s) for transfer trip and dispatch control functions (when needed)

Table 2.3 summarizes the common DG interconnection requirements of utilities for various DG sizes (some details will vary based on utility-specific design and engineering practices).

Demand-Response Integration and "Penetration" Level

Integration of DG may have an impact on system performance. This impact can be assessed based on:

- Size and type of DG design: power converter type, unit rating, unit impedance, relay protection functions, interface transformer, grounding, etc.
- Type of DG prime mover: wind, PV, ICE (internal combustion engine), current transformer, etc.
- Interaction with other DG(s) or load(s)
- Location in the system and the characteristics of the grid, such as:
  - Network, auto-looped, radial, etc.
  - System impedance at connection point
  - Voltage control equipment types, locations, and settings
  - Grounding design
  - Protection equipment types, locations, and settings
  - Others

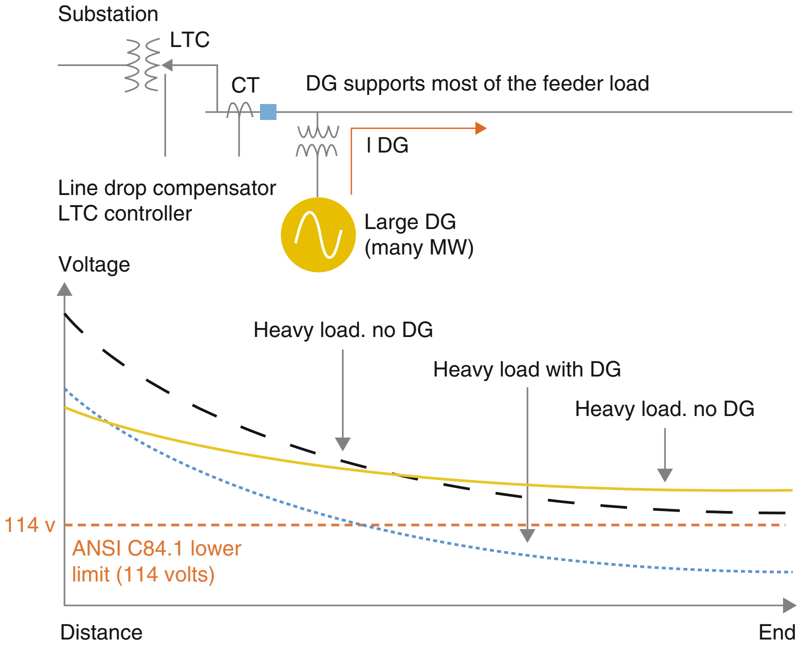


Fig. 2.37 DG connection close to the utility substation

DR system impact is also dependent on the "penetration" level of the DG connected to the grid. There are a number of factors that should be considered when evaluating the penetration level of DG in the system. Examples of DG penetration level factors include:

- DG as a percent of feeder or local interconnection point peak load (varies with location on the feeder)
- DG as a percent of substation peak load or substation capacity
- DG source fault current contribution as a percent of the utility source fault current (at various locations)

Distributed Generation Impact on Voltage Regulation

Voltage regulation, and in particular voltage rise effect, is a key factor that limits the amount (penetration level) of DG that can be connected to the system. Figure 2.37 shows an example of the network with a relatively large (MW size) DG interconnected at close proximity to the utility substation.

Careful investigation of the voltage profile indicates that during heavy-load conditions, with connected DG, voltage levels may drop below acceptable or permissible by standards. The reason for this condition is that relatively large DG reduces the circuit current value seen by the load tap changer (LTC) in the

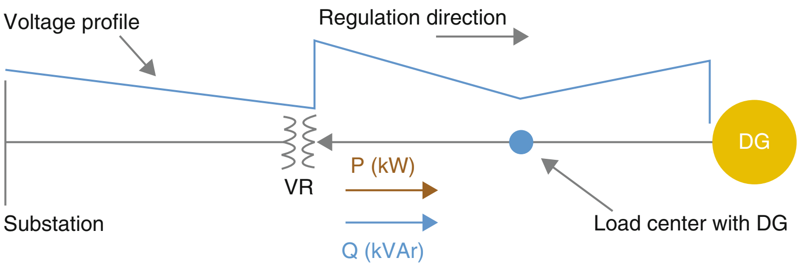


Fig. 2.38 VR bidirectional mode (normal flow)

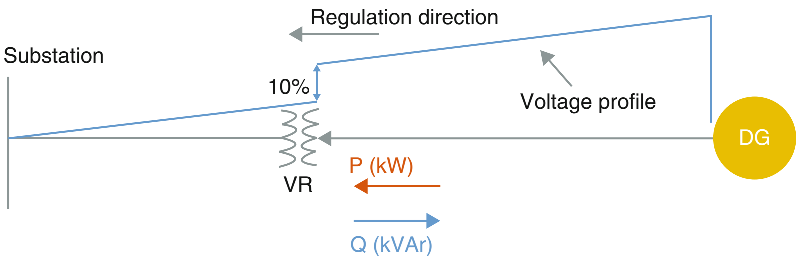


Fig. 2.39 VR bidirectional mode (reverse flow)

substation (DG current contribution). Since the LTC sees "less" current (representing a light load) than the actual value, it will lower the tap setting to avoid a "light-load, high-voltage" condition. This action makes the actual "heavy-load, low-voltage" condition worse. As a general rule, if the DG contributes less than 20% of the load current, then the DG current contribution effect will be minor and can probably be ignored in most cases.

Figures 2.38 and 2.39 show examples of the network with DG connected downstream from the bidirectional line voltage regulator (VR). During "normal" power flow conditions (Fig. 2.38), the VR detects the real power (P) flow condition from the source (substation) toward the end of the circuit. The VR will operate in "forward" mode (secondary control). This operation is as planned, even though the "load center" has shifted toward the voltage regulator.

However, if the real power (P) flow direction reverses toward the substation (Fig. 2.39), the VR will operate in the reverse mode (primary control). Since the voltage at the substation is a stronger source than the voltage at the DG (cannot be lowered by VR), the VR will increase the number of taps on the secondary side. Therefore, voltage on the secondary side increases dramatically.

Distributed Generation Impact on Power Quality

Two aspects of power quality are usually considered to be important during evaluation of DG impact on system performance: (1) voltage flicker conditions

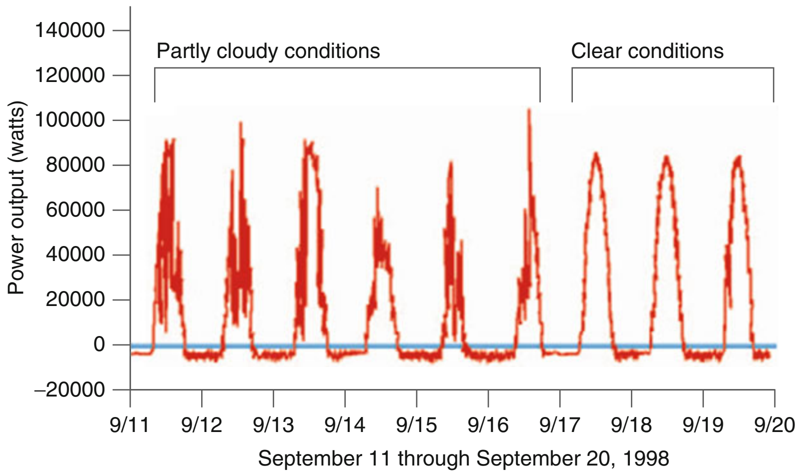


Fig. 2.40 Power output fluctuation for 100 kW PV plant

and (2) harmonic distortion of the voltage. Depending on the particular circumstance, a DG can either decrease or increase the quality of the voltage received by other users of the distribution/medium-voltage network. Power quality is an increasingly important issue and generation is generally subject to the same regulations as loads. The effect of increasing the grid fault current by adding generation often leads to improved power quality; however, it may also have a negative impact on other aspects of system performance (e.g., protection coordination). A notable exception is that a single large DG, or aggregate of small DG connected to a "weak" grid may lead to power quality problems during starting and stopping conditions or output fluctuations (both normal and abnormal). For certain types of DG, such as wind turbines or PV, current fluctuations are a routine part of operation due to varying wind or sunlight conditions (Fig. 2.40).

Harmonics may cause interference with operation of some equipment, including overheating or de-rating of transformers, cables, and motors, leading to shorter life. In addition, they may interfere with some communication systems located in close proximity of the grid. In extreme cases they can cause resonant overvoltages, "blown" fuses, failed equipment, etc. DG technologies must comply with pre-specified by standards harmonic levels (Table 2.4).

In order to mitigate harmonic impact in the system, the following can be implemented:

- Use an interface transformer with a delta winding or ungrounded winding to minimize injection of triplen harmonics.
- Use a grounding reactor in neutral to minimize triplen harmonic injection.
- Specify rotating generator with 2/3 winding pitch design.
- Apply filters or use phase canceling transformers.

Table 2.4 IEEE 519–1992, current distortion limits for general distribution systems

Maximum harmonic current distortion in % of I_L						
Individual harmonic order (odd harmonics)						
I_{SC}/I_L	<11	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h$	TDD
<20[a]	4.0	2.0	1.5	0.6	0.3	5.0
20 < 50	7.0	3.5	2.5	1.0	0.5	8.0
50 < 100	10.0	4.5	4.0	1.5	0.7	12.0
100 < 1,000	12.0	5.5	5.0	2.0	1.0	15.0
>1,000	15.0	7.0	6.0	2.5	1.4	20.0

Even harmonics are limited to 25% of the odd harmonic limits. TDD refers to total demand distortion and is based on the average maximum demand current at the fundamental frequency, taken at the PCC

I_{SC} Maximum short circuit current at the PCC, I_L Maximum demand load current (fundamental) at the PCC, *h* Harmonic number

[a]All power generation equipment is limited to these values of current distortion regardless of $I_{SC}I_L$

- For inverters: Specify pulse width modulation (PWM) inverters with high switching frequency. Avoid line-commutated inverters or low switching frequency PWM; otherwise, more filters may be needed.
- Place DG at locations with high ratios of utility short-circuit current to DG rating.

Distributed Generation Impact on Ferroresonance

Classic ferroresonance conditions can happen with or without interconnected DG (e.g., resonance between transformer magnetization reactance and underground cable capacitance on an open phase). However, by adding DG to the system, the case for overvoltage and resonance can increase for conditions such as: DG connected rated power is higher than the rated power of the connected load, presence of large capacitor banks (30–400% of unit rating), during DG formation on a non-grounded island.

DG Impact on System Protection

Some DG will contribute current to a circuit current on the feeder. The current contribution will raise fault levels and in some cases may change fault current flow direction. The impact of DG fault current contributions on system protection coordination must be considered. The amount of current contribution, its duration, and whether or not there are protection coordination issues depend on:

- Size and location of DG on the feeder
- Type of DG (inverter, synchronous machine, induction machine) and its impedance

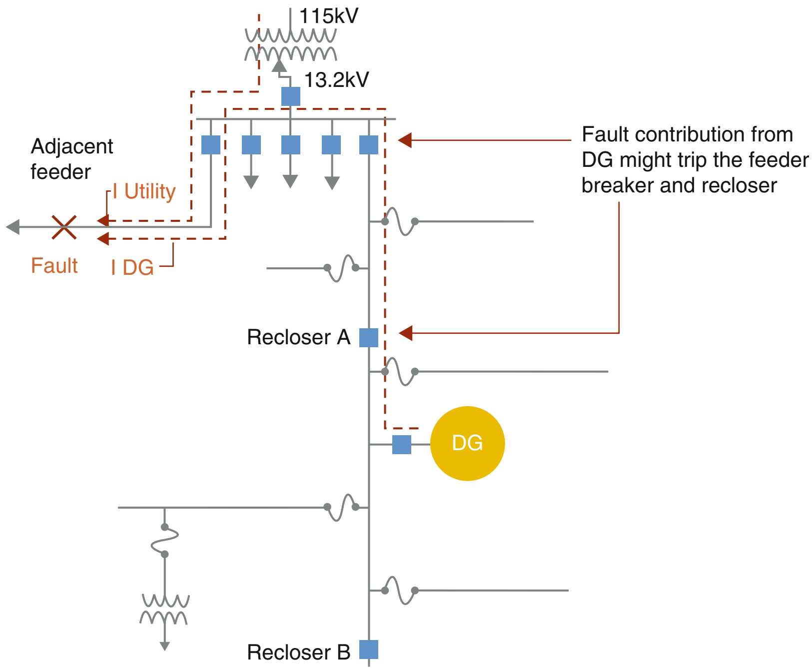


Fig. 2.41 Undesirable protection trip (back-feeding)

- DG protection equipment settings (how fast it trips)
- Impedance, protection, and configuration of feeder
- Type of DG grounding and interface transformer

Machine-based DG (IEC, CT, some micro-turbines, and wind turbines) injects fault current levels of four to ten times their rated current with time contribution between 1/3 cycle and several cycles depending on the machine. Inverters contribute about one to two times their rated current to faults and can trip-off very quickly – many in less than one cycle under ideal conditions. Generally, if fault current levels are changed less than 5% by the DG, then it is unlikely that fault current contribution will have an impact on the existing system or equipment operation. Utilities must also consider interrupting capability of the equipment (e.g., circuit breakers, reclosers, and fuses must have sufficient capacity to interrupt the combined DG and utility source fault levels). Examples of DG fault contribution on system operation and possible protection mis-coordination are shown in Figs. 2.41 and 2.42.

Future Directions

Today's distribution systems are becoming more and more complicated. New methods of producing and storing electrical energy such as PV, fuel cells, and battery storage systems and new methods of consuming electric energy such as

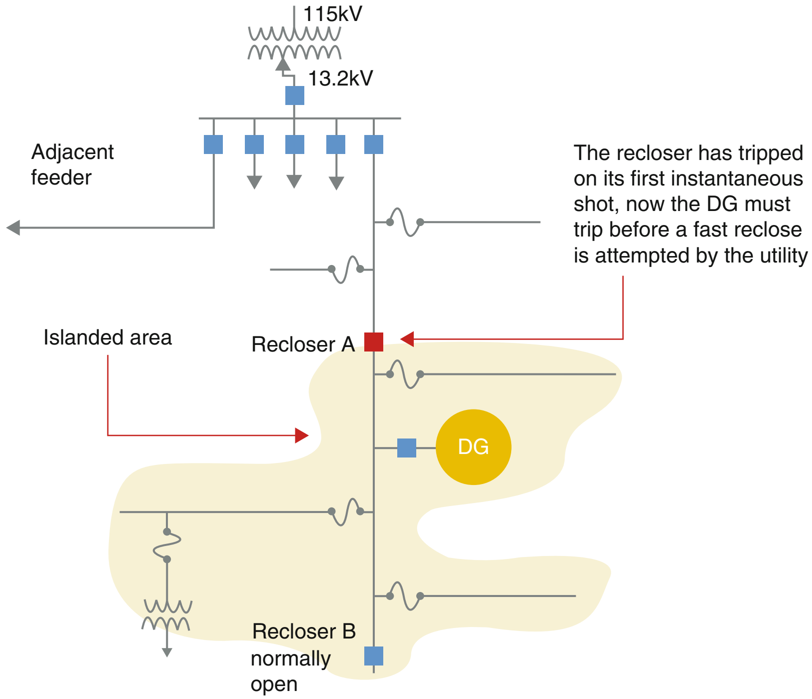


Fig. 2.42 Unintentional DG Islanding

smart appliances and plug-in electric vehicles are being connected to the distribution grid. The rate of adoption of these devices will be driven faster as the economic and environmental benefits improve. In response, the automation systems used to monitor, control, and protect them will need to become more sophisticated.

Many utilities are facing these challenges today in increasingly larger areas of their distribution grid. Many developers are building new green communities that contain enough generation and storage to carry the community's load during an outage. Commonly referred to as microgrid operation, these areas of the distribution grid can be momentarily operated while isolated from the rest of main distribution grid. These microgrids can maintain service to un-faulted sections of the grid during some distribution outages. When these microgrids are connected to the distribution system, utilities are also investigating techniques to maximize the value of the distributed energy resources (DER) during times of economic peak or during capacity peaks. The electric energy in these devices can contribute watts, watt-hours, VARs, and voltage or frequency support during times of distribution system need.

The increasing complexity of the distribution grid will force a need to further integrate the various systems on that grid. The various systems described here will become increasingly integrated. These include the FDIR and Volt/VAR systems. As the FDIR system reconfigures the distribution system, the Volt/VAR system can then optimize the newly configured feeders. Information such as voltage and VARs from the consumers can be used to improve the amount of the Volt/VAR system can control the grid without violating limits at the consumer. Microgrid operation will further push the integration of all of the distribution systems to maintain a safe, reliable, and efficient distribution grid.

This will have the effect of reducing the costs and increasing the overall benefits of these technologies, while maintaining an improved quality and reliability of the electric energy provided to the customers on the distribution system. This stronger economic justification will drive the rate of advance of these new technologies causing a significant impact on the issues and elements of the design of the distribution system and associated automation systems.

There are vast developments happening in the power industry changing whole transmission and distribution world including substations. Smart grid technologies make their way into transmission and distribution world to improve power supply, make it more efficient and reliable, and decrease greenhouse emissions. This became possible due to rapid developments in power electronics and communications. Major areas of developments are as follows:

- Smart metering implies getting metering data from all possible measurement points including end of the feeder over communications in order to maintain proper distribution voltage level for all consumers. This includes deploying voltage regulators, capacitor banks, switches, and other devices in the distribution network.
- Advances in communications imply real-time, live communication between the consumer, the network, and the generation station, so the utility can balance load demand in both directions. Advanced communications are also needed for manual or automatic reconfiguration of the network in case some components of the network are experiencing failures or deficiencies.
- Advanced protective relays and other control devices with enhanced communications and algorithms capabilities to automatically detect, isolate, and reconfigure the grid to maintain uninterruptable power supply.
- Renewable energy sources will continue fast deployment in the distribution network. Wind power, solar power, hydro power units will increase their capacity and output; energy storage systems will be deployed to help system to meet peak demand and offload system generators. Microgrids will provide consumers with reliable and high-quality energy when connection with a transmission n system is lost or in case of isolated community.

A growing number of electric utilities worldwide are seeking ways to provide excellent energy services while becoming more customer focused, competitive, efficient, innovative, and environmentally responsible. Distributed generation is becoming an important element of the electric utility's smart grid portfolio in the twenty-first century. Present barriers to widespread implementation are being reduced as technologies mature and financial incentives (including government and investor supported funding) materialize. However, there are still technical challenges that need to be addressed and effectively overcome by utilities. Distributed generation should become part of a utility's day-to-day planning, design, and operational processes and practices, with special consideration given to:

- Transmission and distribution substation designs that are able to handle significant penetration of distributed generation
- Equipment rating margins for fault-level growth (due to added distributed generation)
- Protective relays and settings that can provide reliable and secure operation of the system with interconnected distributed generation (can handle multiple sources, reverse flow, variable fault levels, etc.)
- Feeder voltage regulation and voltage-drop design approaches that factor possible significant penetration of distributed generation
- Service restoration practices that reduce the chance of interference of distributed generation in the process and even take advantage of distributed generation to enhance reliability where possible
- Grounding practices and means to control distributed generation-induced ground-fault overvoltages.

Bibliography

Primary Literature

1. Smart Grids, European Union, http://www.smartgrids.eu/
2. United States Department of Energy, Office of Electric Transmission and Distribution (2003) Grid 2030: a national vision for electricity's second 100 years
3. EPRI (2009) Report to NIST on the smart grid's interoperability standards roadmap

Books and Reviews

Institute of Electrical and Electronics Engineers (1994) IEEE recommended practice for electric power distribution for industrial plants, IEEE Std 141-1993. Institute of Electrical and Electronics Engineers, New York. ISBN 978-1559373333

Killian C, OG&E, Flynn B (2009) Justifying distribution automation at OG&E. In: 2009 DistribuTECH conference, San Diego, 3–5 Feb 2009

Lathrop S, Flynn B, PacifiCorp (2006) Distribution automation pilot at PacifiCorp. In: Western Energy Institute, 2006 operations conference, Costa Mesa, 5–7 Apr 2006

Lemke JW, Duke Energy, Flynn B (2009) Distributed generation, storage and the smart grid. In: Autovation 2009, The utilimetrics smart metering conference and exposition, Denver Colorado, 13–16 Sep 2009

Stewart R, Flynn B, Pepco Holdings Incorporated (2007) Modeling DA improvements to reliability performance metrics. In: 2007 WPDAC, Spokane, Washington, DC, 3–5 Apr 2007

Weaver T, AEP, Flynn B (2011) Achieving energy efficiency through distribution system improvements: integrated volt/VAR control (IVVC). In: 2011 DistribuTECH conference, San Diego, 3–5 Feb 2011

Westinghouse Electric Corporation (1959) Electric utility engineering reference book, Distribution systems, vol 3. Westinghouse Electric Corporation, Pittsburgh

Chapter 3
Renewable Generation, Integration of

Bri-Mathias Hodge, Erik Ela, and Paul Denholm

Glossary

Ancillary services	All of the actions necessary for supporting the transmission of power from the generator to the consumer and ensuring reliable system operations. Some examples of these services include: voltage and frequency control, generation scheduling, load following, and system protection.
Balancing area	An area in which electricity supply and demand are locally matched and over which a balancing authority maintains system frequency and provides operating reserve.
Independent system operator	The organization that is charged with controlling the operation of the electrical power transmission system in a certain geographic area.
Operating reserve	Extra generating capacity available at short notice to replace scheduled capacity that is currently unavailable due to some sort of system disruption.
Unit commitment and economic dispatch	The process by which generators are scheduled by the grid operator in order to meet expected demand at all timeframes. Commitment refers to deciding which

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3

B.-M. Hodge (✉) • E. Ela
Transmission and Grid Integration Group, National Renewable Energy Laboratory,
1617 Cole Blvd. MS 3811, Golden, CO 80401-3305, USA
e-mail: Bri-Mathias.Hodge@nrel.gov; Erik.Ela@nrel.gov

P. Denholm
Energy Forecasting and Modeling Group, National Renewable Energy Laboratory,
1617 Cole Blvd. MS RSF300, Golden, CO 80401-3305, USA
e-mail: Paul.Denholm@nrel.gov

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*,
DOI 10.1007/978-1-4614-5830-2_3,

	generators will be turned on far in advance of the time period under consideration. Dispatch refers to the decision of how much power each generator will supply during a timeframe that is closer to realization than the commitment period.
Variable generation	Generation from units that cannot be well controlled and thus are not perfectly dispatchable. This term is often applied to generation from weather-driven units, such as wind and solar.

Definition of the Subject and Its Importance

The integration of renewable generation consists of all of the changes in power system operations that are required in order to allow renewable generation sources to play a significant role in the electricity system. The impacts are mostly due to variable generation (VG), like wind and solar power. Historically these technologies have been labeled as intermittent generation, but recent trends prefer the label variable generation [1]. Variable generators have a maximum available generation limit that changes with time (variability) and this limit is not known with perfect accuracy (uncertainty). This uncertainty and variability is in addition to that of the existing system and can therefore create additional challenges for grid operators to maintain their current levels of reliability.

Introduction

Renewable electricity generation encompasses a number of distinct technology types, often classified by their power source, such as geothermal, hydroelectric, marine, biomass, solar, and wind power. Within each of these groupings there are a number of different technologies for harnessing the energy of the power source. However, when discussing renewable integration wind, marine, run of river hydro, and solar generation tend to garner most of the interest. This is due to the fact that the output of these plants is variable and uncertain. Other types of renewable generation are more similar to traditional power sources, such as fossil fuels and nuclear power, in that they are dispatchable. This means that they can be reliably scheduled in advance to provide power when desired, and do not need to rely on the current weather conditions. This is the result of the fact that the availability of their energy source can be controlled. While no generator can guarantee availability at a scheduled time, every generator has the possibility of being unavailable. The unplanned outage rates for dispatchable generators are low enough for the system to treat them as if they will produce at the desired level in the scheduled timeframe, while holding contingency reserves should an outage occur. While other renewable generating units can occasionally have uncertain output, for example, hydroelectric units cannot operate below certain reservoir levels, they are normally treated similarly to conventional units. For this reason the integration of these generating technologies is not normally considered an issue for electrical system operation. Another way of demonstrating the difference between variable generation and dispatchable generation is to examine some of the factors used to describe their patterns of usage. One common metrics is the capacity factor. A capacity factor is the amount of electricity a unit would be physically able to generate divided by the theoretical maximum that the unit would produce if it ran at full capacity over a certain time period. Therefore times when the unit would be down or at a reduced capacity due to forced and unforced outages count against the capacity factor. Baseload power plants typically have capacity factors on the order of 90% or higher. Wind power plants sited in good onshore locations have capacity factors of around 30%, while solar PV plants, even in very good locations, tend to have capacity factors under 20%. However, capacity factor alone does not tell the whole story. For example, a natural gas turbine that is used only for peaking may have a capacity factor under 5%. Even though the turbine is available for a greater percentage of the time, it is not always chosen in the unit commitment and dispatch process due its higher operating costs than baseload plants. For this reason other metrics such as forced and unforced outage rates are also used to characterize unit usage. These metrics however do not apply as well to variable generators and therefore metrics such as capacity value and effective load-carrying capability are often utilized when discussing the availability of wind and solar generators. When the integration of renewable generation is considered, wind and solar generation are usually the focus due to their variable and uncertain nature and their current presence in relatively large quantities in the system.

Worldwide wind power output grew sevenfold and solar photovoltaic (PV) production grew 16-fold from 2000 to 2008 [2]. Wind power has been the fastest growing source of electrical generation capacity in the United States for the last several years [3]. In 2009, there were over 34 GW of wind capacity operating in the United States and over 600 MW of solar PV [3]. These trends have transformed variable generation from a minor component in the electricity system to a contributor whose effects on the overall system must be thoroughly considered. As the future electricity system is expected to contain even larger quantities of variable generation, it is important that means of integrating variable generation are well researched before the higher penetration rates are achieved.

Electricity System Background

The current electricity system is the product of over 100 years of evolution and growth. A central pillar of the system is dispatchable generation, generally from fossil fuels, hydroelectricity, and nuclear power. As most large-scale power systems

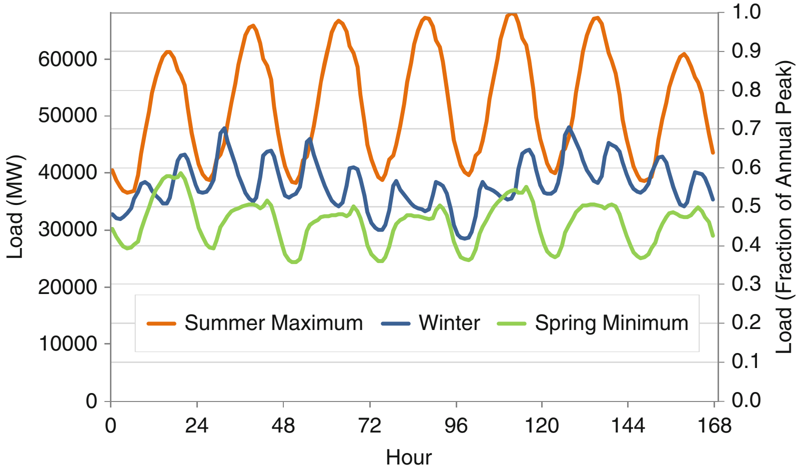


Fig. 3.1 Hourly loads from ERCOT 2005 [4]

have relatively small amounts of electricity storage, electrical supply must always meet electrical demand. The instantaneous matching of supply and demand is needed in order to maintain a nominal electrical frequency. When supply does not equal demand, the frequency can change from its scheduled value (60 Hz in the North America, 50 Hz in many other locations). Frequency that deviates too far from its scheduled value can trigger under-frequency load shedding or over-frequency relays disconnecting machines to prevent damage. If this is not controlled, cascading events can lead to blackouts. This need for supply–demand balance coupled with the fact that the vast majority of demand is noncontrollable necessitates the current structure of system operation. Electricity system operation is a complex process where demand must be forecast and generation scheduled in advance, but numerous types of reserves must also be kept waiting in order to ensure system reliability, should forecast demand errors occur or scheduled generation units become unavailable.

Electricity demand follows strong seasonal and daily patterns. Seasonal demand patterns are highly correlated with seasonal weather patterns. Most systems in the United States tend to have their highest demand during the summer due to the large additional loads attributable to air conditioning. European systems generally tend to reach peak levels during the winter due to the demand from electric space heating. Figure 3.1 demonstrates both the seasonal and daily patterns that occur in the Electric Reliability Council of Texas (ERCOT) system. As may be observed, the summer peaks can be as much as double the spring minimum loads. The daily differences can also be very large during the summer months. Figure 3.1 shows an instance where total system load varies between 40 and 60 GW in the course of a single day. In order to meet these vastly different conditions, utilities build generating units with very different production characteristics.

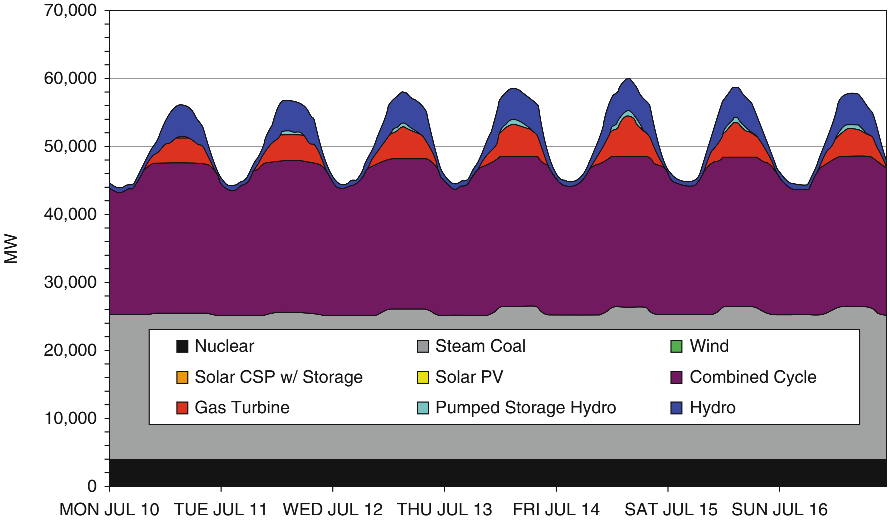


Fig. 3.2 Normal unit commitment and dispatch patterns in the western United States with a very low renewable generation penetration rate [5]

Baseload power plants are utilized to cover the large amounts of demand for electricity that fall below the minimum daily demand level. Coal-fired and nuclear plants are the two most typical types of baseload plants. They are often very high capacity plants that have very large capital costs, and relatively low operating costs. Baseload plants also typically require long start-up times and cannot ramp rapidly to follow changes in load. For these reasons utilities prefer to run the plants as close to maximum output as possible the majority of the time they are in service. Variations in load are usually met through the use of another type of generating unit, the load following plant. These units can be further subdivided into intermediate load plants and peaking plants. Intermediate plants are typically used to meet the daily variability in demand and are often hydroelectric or combined cycle plants fueled by natural gas. Peaking plants usually have a very high marginal cost of production, and as such are only utilized during periods of extremely high demand, often less than a few hundred hours per year. These plants are often natural gas or oil-fired simple cycle turbines. The normal usage patterns of baseload, intermediate, and peaking units can be observed in Fig. 3.2.

The generating units that will meet the expected load are usually scheduled 1 day beforehand in what is known as a security-constrained unit commitment. This optimization of total system costs schedules the start-up of units based on forecasted loads for the next day. Because system load cannot be perfectly forecast, there is the need for another assignment process closer to the actual time point. This process is known as security-constrained economic dispatch and it changes the level of output of units already online in order to ensure that supply meets demand. The amount of time ahead that this process occurs varies by system operator.

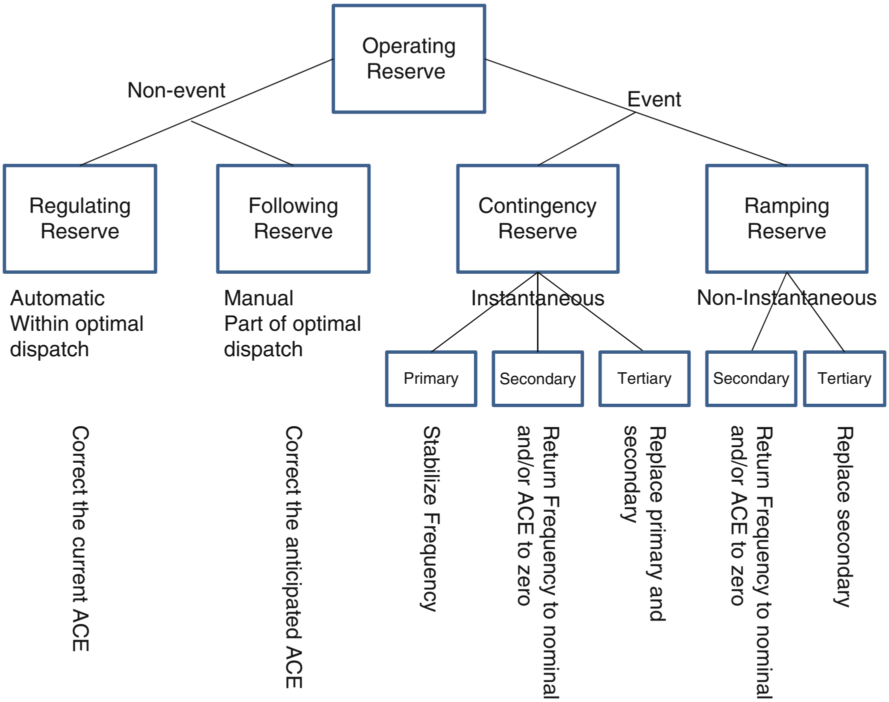


Fig. 3.3 Illustration of reserve types [6]

Advances in telecommunications have allowed some systems to operate at smaller dispatch timings, down to 5 min ahead. Both of these processes should ensure that the commitment and dispatch are secure considering the generator constraints, transmission network constraints, and n-1 contingency constraints. The n-1 criterion states that a system must be secure following any credible single outage, be that a generator, or other system component (e.g., a transmission line).

In addition to advanced scheduling that needs to occur to balance the generation, system operators often schedule capacity as operating reserve to be used in case of unexpected changes from schedules or for variability occurring within a scheduling interval. Operating reserves can be classified according to the type of situation that triggers their deployment, the timescale of the response, and the direction of deployment. Figure 3.3 illustrates the different types of reserves based upon the event type and the speed of response. The most commonly utilized reserves are those that are required during normal operating conditions. Generating units must be kept in reserve in order to respond to continuous differences between forecasted and actual conditions. This function falls under the category of reserves known as regulation reserve. It is employed to respond to the minor random fluctuations that occur around normal load in order to maintain system frequency. Regulation reserves are required in both the up and down directions, in other words, regulation reserve must be able to both increase and decrease output to match the fluctuating conditions. Regulation reserves are generally employed on the sub-minute timescale. More sustained trends over the timescale of minutes are handled through following reserve (often called load following reserve in practice).

In addition, reserves must be kept on hand should a generating plant or transmission line currently importing power suddenly become unavailable. Contingency reserves are those in place for unexpected events that change the instantaneous availability of generators or transmission. Primary reserve, that is, frequency responsive reserves, responds within seconds in order to stabilize the system frequency after a major disturbance. Secondary reserve is then used to restore the frequency back to its scheduled setting. Tertiary reserve is then used to replace the reserve used during the event so that the system is secure toward a subsequent event. Ramping reserve is utilized in order to respond to events that occur over a longer duration, such as variable generation forecast errors or ramping events. Ramping reserve also requires frequency or control error to return to its nominal setting and for it to be replaced in case of a secondary event. However, due to the slow time it takes for these events to occur it is usually not necessary to stabilize the quickly changing frequency. Reserves are also often classified according to their synchronization status. Reserves provided by units that are already running and synchronized to the system are known as spinning reserves, while non-spinning reserves are not synchronized and thus take longer to respond. Fast response reserve, such as regulating reserve and primary or frequency response reserve, require spinning reserve exclusively while slower reserve categories usually contain mixtures of both spinning and non-spinning reserves in different proportions.

Characteristics of Renewable Resources

As described in the Introduction, the discussion of renewable resource characteristics is generally limited to wind and solar generation, since they operate quite differently from other types of generation. While both are considered variable resources, wind and solar generation have distinct characteristics that need to be considered when attempting to integrate them into the electricity system. Perhaps the most important difference is in their diurnal patterns. Solar generation output follows the daily cycle of the sun in its particular location on earth, and thus is limited to daylight hours. Wind power output may occur during both daylight and night hours, but in most locations output has a tendency to be higher and more consistent during the night hours. This is demonstrated in the plot of average wind power output over the course of a day for the year 2004 in the MISO system seen in Fig. 3.4. Plotted on the same graph are the average locational marginal prices (LMPs) for the MISO system over the course of a day. As may be observed, the wind output tends to be highest when energy prices are lowest, corresponding to times of low demand, and dips during the daily peak when prices are highest.

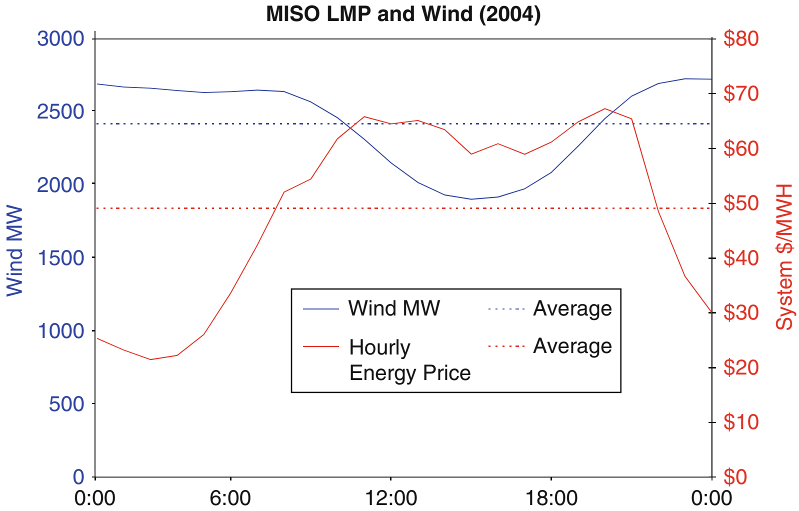


Fig. 3.4 Average energy prices and wind power output over the course of the day in the MISO system [7]

Solar generation can be subdivided into two different categories: concentrating solar thermal and solar PV. From an operational perspective the biggest difference between the two is that concentrating solar thermal plants can have thermal storage capabilities. This allows them to store energy that can later be used to provide electricity during periods where output would be diminished if relying solely on immediate solar irradiation. Solar PV on the other hand is completely reliant on the immediate solar irradiation and thus has reduced output in cloudy weather, and no output at night. The difference in daily profiles for concentrating solar thermal plants with storage versus PV plants can be seen in the July portion of Fig. 3.5. Another major difference between the two technologies is the locations in which they can be deployed. Concentrating solar thermal plants require larger areas for installation and the high capital costs dictate that they be deployed in only very high quality resource areas with high direct normal irradiance. Solar energy contains both a direct and a diffuse component. The direct component is the light from the solar beam and the diffuse component consists of light that has been scattered by the atmosphere. The direct component can be focused using mirrors or lenses and accounts for 60–80% of total solar insolation in clear sky conditions, but decreases with high levels of humidity, cloud cover, and atmospheric aerosols. This limits their construction to arid regions, such as those in the southwestern United States. PV on the other hand can be deployed in nonutility scale system sizes and thus can be present in large plant configurations or distributed over a number of locations, such as rooftops. This can be an important distinction in the case of very high levels of distributed PV penetration as the output from these locations only appears to the system operator as reduced load.

Wind generation is also subdivided into two categories, though usually based on the location of the wind plant, not the technology being used. Onshore locations

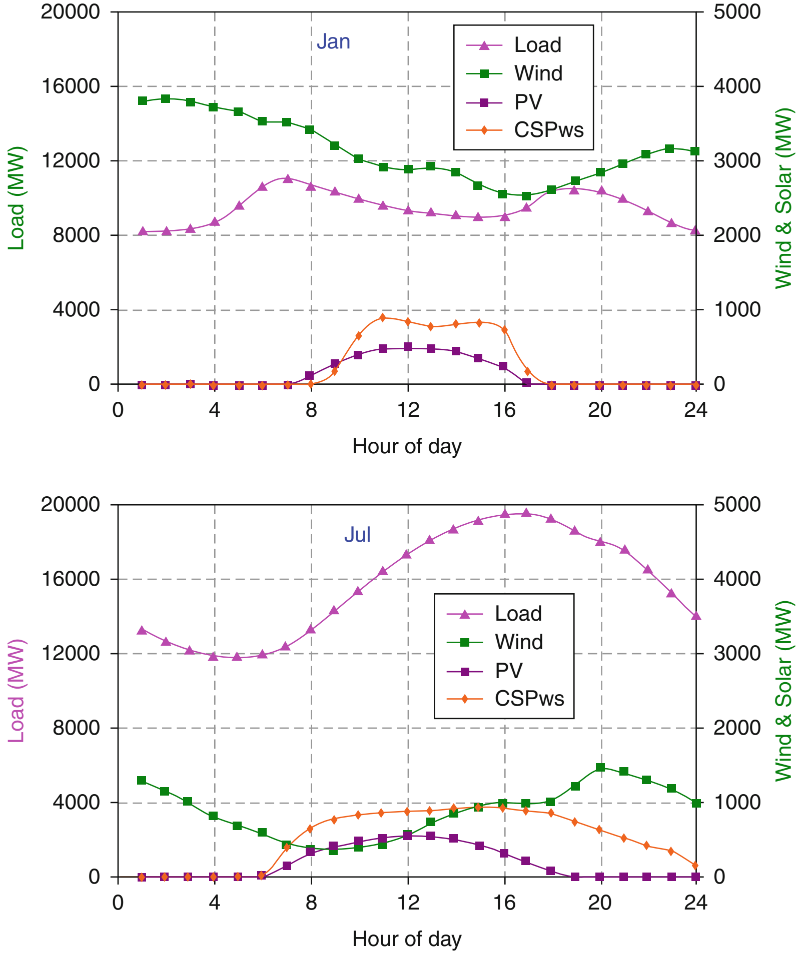


Fig. 3.5 Load, wind, solar pv, and concentrating solar thermal (with storage) daily profiles for both January and July in Arizona in a high renewable penetration scenario [5]

have been the dominant choice thus far as wind power capacity has grown. However, offshore locations generally have more consistent output and the accompanying higher capacity factors are attractive. Offshore locations tend to involve the construction of larger turbines, and are usually more expensive due to the difficulties associated with their construction in large bodies of water. While onshore locations can require building new transmission, the additional transmission demands of offshore locations are more extensive, but conversely have the advantage that they are generally located closer to load centers.

One very important positive aspect of both wind and solar is the large size of the resource base. For example, while global electricity consumption in 2005 was estimated to be 16.6 PWh, the resource base of global onshore wind power, restricted to locations with a minimum 20% turbine capacity factor, is approximately 700 PWh [8]. The global offshore resource base, while not as large, is still considerable. Even after restricting the locations to those within 50 nautical miles of the coast and water depth of 50 m or less, the potential energy production is still approximately 80 PWh [8]. The total potential capacity of offshore wind power in the United States is over 4,000 GW, based on locations within 50 nautical miles of the coast with average annual wind speeds at 90 m greater than 7 m/s [9]. Solar PV power has an even larger potential resource base, with the technical potential estimated to be approximately 4,100 PWh per year by 2050 [10], while concentrating solar thermal potential is estimated to be between 630 and 4,700 GW of capacity [11]. As a point of comparison, small and micro hydroelectric plants have an estimated global technical potential of 150–200 GW of capacity [11]. These enormous resource bases, combined with the current low utilization of the potential energy from these sources, make renewable resources attractive options for long-term planning of energy supply sources.

Because these variable generation sources are not dispatchable, they present new issues for integration into the electricity grid. One major difference is that they are often considered to be a negative load, instead of a generation source. Essentially, any variable generation that is being produced at the current time is accepted and reduces the total load that must be met by conventional generators. This residual load is equal to normal demand minus electricity from renewable generators, and has greater variability than load alone. While this is a suitable representation for low levels of variable generation penetration, it will need to change in order to accommodate higher levels. In fact this is already starting to change as wind is being used to alleviate transmission constraints.

Generator Modeling and Interconnection

There are many technical aspects that concern the physical connection of renewable plants to the electricity grid, and their contributions to stable system operation. As renewable power becomes a larger contributor to the electricity system, it must also take on the responsibilities of maintaining system security. We focus mostly on wind in this section due to the currently higher market share. The requirements of wind turbines connected to the electricity system are prescribed through grid codes that detail the turbine contributions to ensure power system stability. The interactions that occur between the grid and the wind plant are heavily influenced by the type of machine in use and the stiffness of the grid. There are four different types of wind turbine machines commonly in use (Types 1–4), differing in their ability to control output power and reactive power and the type of generator utilized. The creation of accurate models of the physical representation of these different turbines can aid in the understanding of the effects that wind plant interconnection will have on the system. Small wind plants may be connected at low or medium voltage distribution networks. In a larger plant many turbines are connected together through a collector system and then connect to the substation where a transformer steps up the voltage from the distribution level to the transmission level.

Fault Ride Through

One common requirement made of wind turbines is fault ride through in the case of a system fault. Early wind plants would simply disconnect from the system when a system fault occurred. In systems with larger amounts of wind power this disconnection would exacerbate the problem [12]. This requirement specifies that the generator must stay online during faults with a duration and voltage variation under certain thresholds that vary by system. Further advances in wind turbine technology will allow for the post-fault recovery characteristics of turbines to be better than those of conventional generators. While wind turbines must comply with the requirements for normal network operation, they must also have system protection that prevents damage to the turbine during events that take the system out of its normal operating ranges. Plants typically are required to have protection from over- and under-frequency, current and voltage events. Additionally, the type of power electronics utilized by any renewable generation can significantly enhance its response to events.

Frequency Control

Frequency fluctuations in the power system result from an instantaneous difference between the amount of power being generated and the demand, including system losses. Wind plants can contribute to the stabilization of frequency in over-frequency events by decreasing output, either through blade feathering or shutting down individual turbines. Under-frequency events are more challenging because they require additional generating capacity. Since the wind speed cannot be increased to produce more generation when desired, this requires holding a portion of possibly generating capacity free, despite the lost revenue incurred. If decreases in the wind power output can be forecast, the turbines can reduce their output slowly in advance reducing the impact of the negative ramp rate.

Voltage Control

In order for a power system to operate as designed, the voltage throughout the system should be kept within the normal operating range (0.95–1.05 of the set point), though transients are allowed a wider range (0.9–1.1). The impedance of a power line causes a change in voltage between the two ends when a current is flowing. The introduction of renewable generators changes the power flow in the system, and hence the local voltages. Unlike frequency, voltage is a local phenomenon that cannot be controlled system-wide. Thus voltage must be kept within its specified range locally by generators in the area, or by power electronics, such as tap-changing transformers. Voltage control in transmission lines is normally adjusted through the consumption or supply of reactive power by generators, or through capacitor banks or flexible AC transmission system (FACTS) devices.

Reactive Power

Wind turbines with induction generators consume reactive power, which can lead to voltage collapse, if not properly compensated, and increased system losses from voltage drops and reactive current, respectively. To mitigate the effects, reactive power can be supplied through the inverter on variable speed turbines, or through capacitors in fixed speed turbines.

Interconnection Queue Process

The process by which a new generator receives the requisite permissions from the local grid operator to connect into the transmission system is known as the interconnection queue process. This process enables the system operator to conduct feasibility, system impact, and facility studies to ensure that the new generator will not have negative effects on system operation. The process also includes the planning steps necessary for generator participation in local markets and the acquisition of necessary transmission rights.

Operating Impacts

With the increasing amounts of wind power being added into electricity systems in recent years, a number of studies have been conducted in order to assess the impacts on the system incurred by integrating these large amounts of wind power. These studies typically examine two cases, one with wind and one without, and compare the results of statistical and production cost simulation analysis in order to determine the cost differences in system operation that may be attributed to wind power. A common assumption is that system reliability must be held at a constant level, which may necessitate the inclusion of additional operating reserves in the with wind case to remedy the increased system variability and uncertainty introduced by the wind plants.

Regulation

The goal of regulation is to compensate for the system variability at small timescales. The majority of this variability is due to normal load fluctuations, with an additional component of variability attributable to conventional generators minor deviations from their set points. The addition of renewable generation to the system adds another source of variability that must be accounted for. However, the impacts of wind generation on regulation services have been found to be relatively minor. For example, the addition of 3300 MW of wind into a system with approximately 30 GW of system peak load required only 36 MW of additional regulation [13]. This is due to the fact that the variability of a large number of wind turbines aggregated together is fairly small at the regulation timescale. Additionally, load and wind power are uncorrelated on the small timescales considered for regulation and thus their fluctuations are rarely amplified and often cancel each other out. However, studies are continuing to use different methods to determine the impact to regulation reserve, and the requirements differ sometimes substantially.

Load Following

One of the areas where the integration of renewable generation sources can have a major impact on grid operations is in the load following domain. In the minutes to hours time frame in which load following operates, there can be large ramps in renewable generation output. The addition of variable generation to load increases the overall system variability within this timeframe. For example, these effects occur when wind power output starts to ramp down following its diurnal pattern, just as the morning load starts to ramp up. This case marks extremely poor timing for the system operator as they must not only be able to handle the increase in load, but must simultaneously replace power that was being generated.

Wind Uncertainty Costs

The main costs of wind uncertainty are the result of having a suboptimal generation mix online due to an inaccurate forecast. One example of a commitment cost can be seen in the case of wind over-forecasting. If the wind output is forecast to be high, but is actually much lower in real time, a unit must be ready to serve the load that the wind was scheduled to serve. If this amount is significant it is possible that a slow starting baseload unit should have been made available at this time. In this case the wind overestimation causes an expensive fast starting unit to produce when a cheaper, but slow starting, unit would have been chosen if the forecast was more

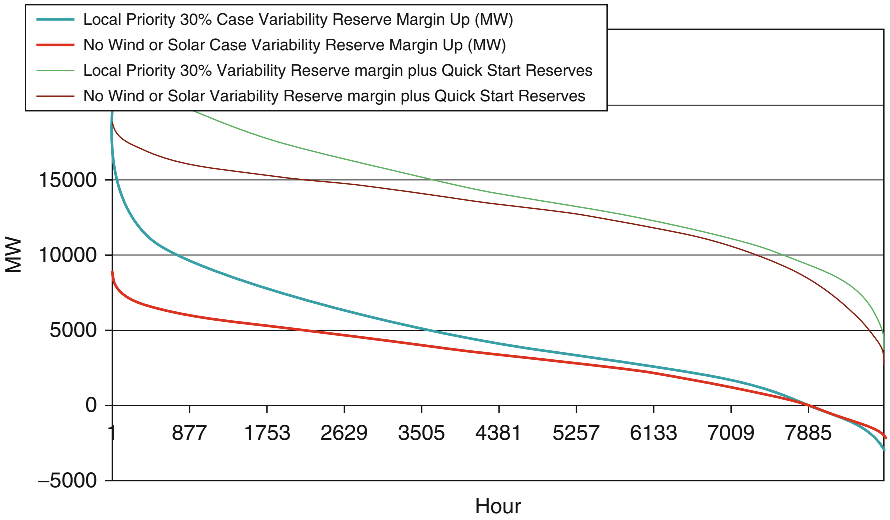


Fig. 3.6 Increase in available spinning reserves for a base case and a high renewable penetration rate case [5]

accurate. On the other hand, if the wind is under-forecast there may be more plants online than is necessary, causing higher start-up and fuel costs and leading to the possibility of wind curtailment.

It is important to note that since individual wind and solar plants are currently always smaller than the largest generator in the system, additional contingency reserves are not required by traditional metrics, such as the n-1 criteria. This could change in the future at higher renewable penetration rates if very large renewable generation plants are installed, or in the case of number plants being routed through a single large transmission line. However, at very high renewable penetration rates it can be expected that very large renewable forecast errors could lead to situations where even contingency reserves are not sufficient to cover the error, as has been seen in a study of the western United States [5]. In the Western Wind and Solar Integration Study (WWSIS) it was found that these errors occur in approximately 1% of operating hours. While additional spinning reserves could be added to the system to handle these extreme events, it was proposed that some form of demand response would be more economic. While additional reserves of up to one to one backup have been proposed, this ignores the fact that the addition of renewable generation increases the amount of up-reserves available in the system. The incorporation of increased renewable sources causes the backing down of traditional generators, creating larger amounts of spinning reserve available to the system, as was shown in the WWSIS. One example of this result is shown in the up-reserve duration curve in Fig. 3.6. The amount of down spinning reserve is also increased as wind curtailment provides a very simple option.

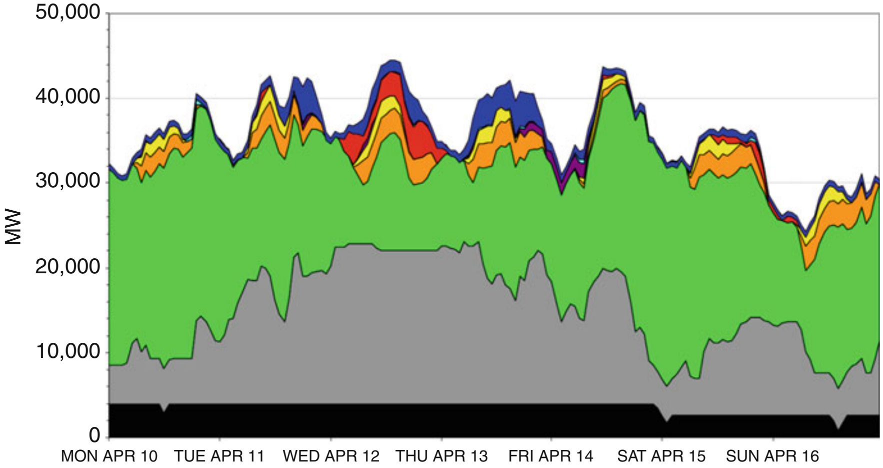


Fig. 3.7 An example of unit commitment and dispatch in the western United States with 30% renewable generation penetration [5]

Thermal Unit Cycling

At very high penetrations of renewable generation it is not only peaking and intermediate units that are displaced.

Figure 3.7 shows an instance where baseload power is forced to produce at levels below maximum generation because of the large amounts of renewable power provided in a 30% renewable penetration scenario. When baseload generation must frequently change its level of output it is referred to as cycling, and it imposes additional wear and tear costs on units that were designed for near constant output. This particular instance is a case where a combination of low demand and high wind output combine to produce results that are far from normal system operation. The most damaging cycling events for thermal units are those where large changes in temperature cause material fatigue, decreasing the normal life of generator components. For this reason unit start-ups are the most damaging due to the large temperature differences between the operating mode and the shutdown mode. The length of the shutdown period is also important with hot-starts and warm-starts being preferred to cold-starts. Though less damaging than shutting down, bringing the generator down to its minimum output level, and then back up to maximum output, also creates large temperature changes that increase wear and tear on the unit.

Market Considerations

While it has been shown that low levels of renewable generation can be incorporated into the electricity system, with few or no changes to current system operations, the variable and uncertain nature of wind and solar power do create limitations on the penetration rates that are reasonably achievable within the context of the existing system. The effects of the uncertainty and variability are mitigated by large day-ahead and hour-ahead markets that provide many options for the balancing of supply and demand.

Balancing Area Cooperation

In 2010, there were over 100 balancing areas in the United States and Canada. Recent trends favor balancing area consolidation and the number of balancing areas is expected to continue to decrease. This is a positive development for the integration of renewable generation. Small balancing areas suffer larger consequences from routine variability. This is true for both supply and demand. For example, in a system with 100 MW total demand, an increase in demand of 10 MW is very significant, while in a system of 10,000 MW the 10 MW change is much more easily accommodated. Aggregated demand is also less variable for larger systems due to the larger number of individuals, and hence the smaller roles of the individuals in the aggregated system load. The variability of renewable generation also decreases with the aggregation of multiple generators in different locations. This geographical diversity of variable generation is due to the fact that the further the two generators are apart, the less likely they are to be affected by the same weather patterns, and hence the correlation of their power output is lower.

Figure 3.8 shows how the wind speed correlations decrease between geographically distant locations. Larger balancing areas will increase the potential area from which renewable generation can be drawn, and therefore lower the overall variability of total renewable output.

Reserve Sharing

Balancing areas may also choose to cooperate through other mechanisms besides full consolidation. One way that they may reduce the costs of variable generation integration is through reserve sharing agreements. Under these conditions the balancing areas independently schedule and dispatch generation to meet their own loads. However, since certain types of reserves, such as contingency reserves, are utilized only infrequently they may serve as backup to multiple balancing areas, should sufficient transmission capacity be available.

Dispatch Intervals

Another means by which markets may reduce the effects of system variability is through the use of more frequent market operations than the typical 1-h period for dispatch. Sub-hourly balancing markets aid in the integration of renewable

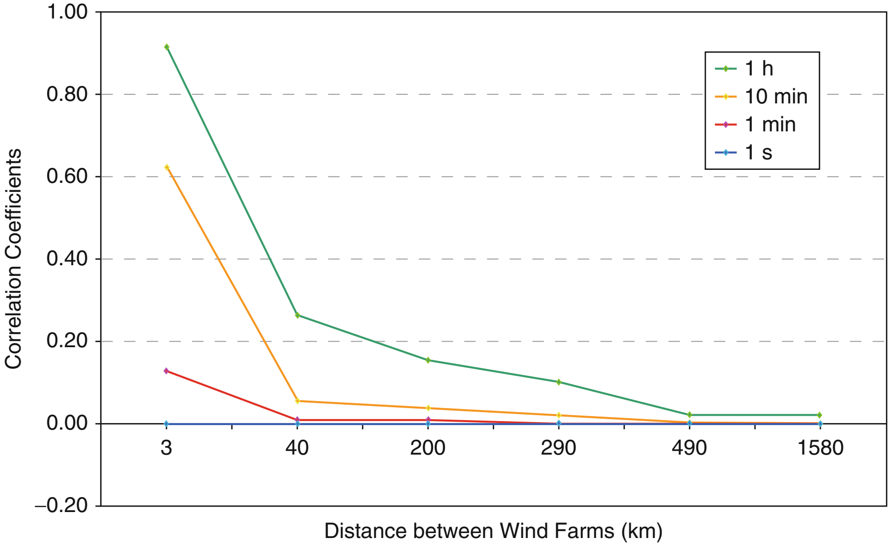


Fig. 3.8 Wind speed correlations with distances between locations in the United States [14]

generators by enabling the utilization of existing flexibility in the system and reducing the requirements for ancillary services. In addition, they allow the renewable generators to revise their production forecasts closer to the operating period to minimize forecast errors and thus imbalances.

Ancillary Service Markets

Ancillary service markets will play a key role in the integration of high levels of renewable energy resources. However, the current services offered may not be sufficient and new services should be created based on power system reliability requirements. For example, load following is an important system function with large amounts of renewable generators due to the increased system variability. While this is currently supplied through other units in the energy market, at high renewable penetration rates a market for fast ramping resources may prove to be advantageous. Another key consideration is the adoption of varying ancillary service requirements in response to current renewable generation conditions. When the amount of wind power currently being produced is high, the securing of large amounts of load following reserves would be wise, should a significant decrease in wind power output occur. However, when the wind power output is at a low level, the need for load following reserves is significantly decreased. By co-optimizing not only the choice of ancillary service providers with energy providers, but also the amount of ancillary services, the cost of variable generation integration can be reduced.

Capacity Markets

Well functioning electricity markets are required not only to supply the necessary amount of energy to meet demand at each point in time, but also to supply the generating capacity necessary. The calculation of the capacity credit for variable generation is one of the most contentious issues related to renewable integration, with many different methods being utilized in different systems [15]. Since a capacity credit is normally based on a system reliability measure, such as loss of load probability, it is effectively a measure of a units contribution to system reliability. Since the need for reserve capacity is highest at times of high system stress, when a loss of load is most likely to occur, capacity credit measures value available capacity at these times as more valuable than at times with a low probability of unserved load. Variable generators have a lower capacity credit than all but the most unreliable of conventional generators due to their high effective forced outage rate. These high effective forced outage rates are the result of weather-induced unavailability and not generator failures. Since the correlation between wind power output and peak load is weak in most locations wind generators tend to have fairly low capacity credit, as the timing of the capacity availability is so critical in the credit determination. On the other hand, solar generators tend to have relatively higher capacity credits, despite their generally lower overall capacity factors. This is due to the fact that the most regular instances of high solar output correspond to the same times as peak demand.

Locational Marginal Prices

Variable generators generally have high capital costs, but low variable costs when compared with conventional generators. The practical implication is that variable generation units will have lower marginal costs of production (often bid as zero) that they may submit as bids into energy markets. When the amount of variable generation is sufficient to remove the highest bidding unit that would otherwise be producing, the market cost of energy at that point in time is reduced. This reduces the total revenue collected by all generators and thus total system costs. Transmission system congestion leads to different prices at different nodes in the system, known as locational marginal pricing (LMP). When government policies for renewable energy production, such as production tax credits, are combined with very high renewable output at a particular point in the transmission system, the possibility of negative LMPs arises. In this case the production incentives offered make it economically efficient for units to pay to produce electricity. This situation is not sustainable in the long-term, neither for the variable generator nor for conventional units in the same area. If this situation occurs at a high enough frequency it could lead to the decommissioning of conventional units in the area, to the detriment of system reliability that relies on those units for reserve capacity [16].

Transmission Planning

The sites that offer renewable generation sources the highest capacity factors are often located far from load centers. This dictates that new transmission must be built in order to utilize these areas with high renewable resources. While the need for new transmission is easily identified the process times for permitting and construction of the transmission often exceed those for the siting and construction of renewable generation. This can lead to situations where large amounts of renewable generation cannot be utilized because of transmission bottlenecks.

Transmission planning is not only important for gaining access to renewable resources, it can also be important in helping to integrate large amounts of renewable generation into the electricity system. Additional transmission between balancing areas or interconnects can allow for better utilization of renewable generation by providing alternative outlets for generation above what can be utilized within the local area. Having strong transmission ties between areas is a critical element in taking advantage of the geographic diversity of renewable resources. When the current renewable generation is low in one area but high in another additional transmission allows this energy to be utilized instead of curtailed. One proposed project in the United States that plans on utilizing increased transmission to aid renewable integration is the Tres Amigas project [17]. The North American electricity grid is split into three essentially independent interconnections: the Western, the Eastern, and Texas. The Tres Amigas project aims to provide expanded transmission links through the addition of 5 GW DC superconducting lines between each of the interconnections. The proposed site on the border of New Mexico and Texas is located close to areas of excellent wind and solar resources.

An even more ambition project for the integration of vast renewable resources over a large geographic footprint is the DESERTEC project [18]. This project aims to create a supergrid throughout Europe, the Middle East, and North Africa. This supergrid would open access to a larger number of renewable resources, including concentrating solar electricity from the Middle East and North Africa and wind power from Northern Europe. The enormous footprint of the project would ensure a smoothing of the renewable generation sources and demand sinks.

Enabling Greater Renewable Penetration

Just as there are currently a number of generation technologies utilized to fulfill electricity supply, there will be a number of technologies and strategies needed in order to enable the inclusion of larger amounts of renewable generation into the electricity system. Figure 3.9 shows a conceptual cost ranking of different demand and supply side technologies and systems that provide the electricity system with additional flexibility, and thus can help in the integration of variable generation. The inclusion of a number of different renewable generation technologies, with

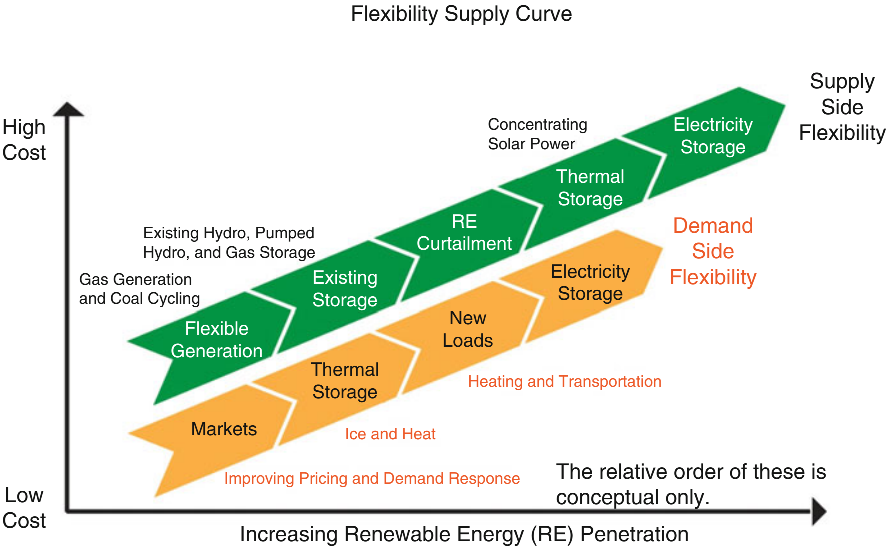


Fig. 3.9 The flexibility supply curve shows a number of different methods of providing system flexibility that may be useful in integrating renewable generation sources [19]

complementary generation characteristics, in future capacity expansion will also help to facilitate operating a high renewable electricity system. Dispatchable renewable sources, such as geothermal, biomass-fired thermal and hydroelectric plants, are able to contribute to renewable generation goals without significantly altering system operations. Geothermal and biomass-fired plants can serve as baseload units that reduce the amount of variable generation necessary at all times. Hydroelectric units can also serve this function, but may better serve the system by providing load following capabilities for variable generation due to their quick response times. However, the limited geographic potential and/or economic costs of these plants dictate that large capacities from variable sources will also be required to meet high renewable penetration goals. A number of different strategies for mitigating the effects of these plants' variability and uncertainty are described in what follows.

Variable Generation Forecasting

Renewable generation is both variable and uncertain; however, the uncertainty is a much more critical factor than the variability. If the variable output of renewable generation was known in advance the impact would be considerably reduced. The variable output could still be scheduled in a normal unit commitment and dispatch system, and would in fact be dispatchable. It is the uncertainty associated with renewable output that is most troubling. Thankfully, the future output of a variable generator is not completely random at smaller timescales, due to the fact that it is weather-driven. Forecasting techniques can be used to estimate the future output and this information can be incorporated into future generation plans. However, forecasting results tend to improve with reduced lead times between making the forecast and the time of realization. The inaccuracies associated with forecasting at longer timescales, in conjunction with the long start-up times of baseload units, diminishes the practical impacts of wind forecasting in particular. Numerical weather prediction models are commonly used to make wind forecasts for the day-ahead unit commitment process. Further improvements to these models, and their use at smaller geographic distances, has the potential to improve the utilization of variable generation through better forecasting.

Stochastic Planning and Operating Tools

One way in which variable generation forecasting can be better utilized is through the use of stochastic unit commitment and economic dispatch models. Instead of a simple point forecast these models incorporate a number of different scenarios of variable generation power output, with associated probabilities, during the future time frames under consideration. Through their explicit consideration of the stochastic nature of the variable generation these models are able to produce more robust schedules that can respond more easily to the different possible variable generation scenarios. The more robust schedules produced tend to produce lower average system costs than those that utilize only a point forecast [20]. Improved forecasting that considers not only the most likely value for the next time point, but also a consideration of the range and likelihood of possible values will increase the impact of stochastic operating tools. For this reason the consideration of the distribution of forecasting errors for variable generation production is important as it can inform the creation of more realistic forecasting scenarios. Improved stochastic programming algorithms that reduce the computational time necessary to solve for an optimal schedule will also increase the effect of these tools by allowing for the consideration of a larger number of scenarios and their application at smaller timescales.

Faster Markets

As the time between the forecast of variable generation and the actual production time decreases, so does the average error of the forecast. For this reason the implementation of faster dispatch markets can help lead to further renewable generation penetration as it decreases the costs associated with variable generation uncertainty. By having less time between the time of forecast and the actual time of output, more current information can be utilized in deciding the forecast. Since day-ahead markets followed by 1-h dispatch market tend to be the normal historical system of market operation, sub-hourly markets are necessary for further improvements. These sub-hourly balancing markets also provide another means by which the regulation and load following reserve impacts of variable generation may be reduced.

Demand Response

Another possible approach to incorporating larger fractions of renewable generation into the electricity system is known as demand response. This approach is based upon changing one of the main tenets of traditional electricity system operation: varying generation to match an uncontrollable load. Demand response gives the system operator control over the timing of some portion of load by allowing blocks of load to be delayed. This approach has traditionally been used by system operators as a last resource during times of very high peak loads. Large industrial loads often structure their contracts with utilities so that they receive either payments or lower base rates for allowing the utility the privilege of interrupting their service periodically, up to a maximum number of occurrences. Industrial customers are preferable from the utilities' perspective because they allow a large reduction in load through a single customer interruption. Large commercial installations also have the possibility of participating in demand response programs, as the heating or cooling of a large commercial building could be a significant resource.

The adoption of "SmartGrid" technologies has the promise of allowing residential customers to also participate in demand response programs. Unlike industrial loads, individual residential customers are a very small percentage of the total system load. However, if the utility can simultaneously control a large number of large-load distributed residential appliances, such as air conditioners, the aggregated effect can be comparable to the response provided by a large load industrial customer. It is important to note that demand response programs do not significantly reduce total electricity usage, instead the load is shifted from times of high demand, when additional generation may be unavailable, to periods of lower demand. Household demand response is limited by cost to large appliances, and by consumer acceptance to appliances whose usage patterns are somewhat time insensitive. For example, a refrigerator's load can be postponed, but only for very short timescales, so that the contents do not spoil. On the other hand, a dishwasher turning on can presumably be delayed until the total demand levels fall at night, with far less negative effects to the consumer. In the extreme case one can imagine the linking of certain appliances' usage to the current level of variable generation output. A related idea is the use of time of use pricing for residential electricity, as opposed to the flat-rate (or limited peak/off-peak split) rate structure that currently prevails.

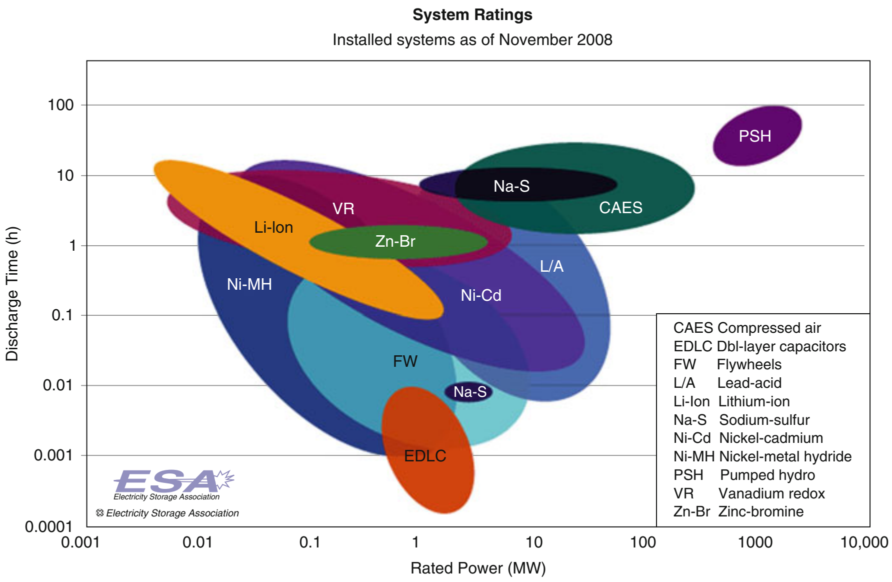


Fig. 3.10 The range of power and energy combinations available for different storage technologies

The most troublesome aspect of time of use pricing is the limited ability or desire of residential customers to react to different prices. For extensive changes in residential usage patterns the time of use pricing scheme would need to be paired with meters that can be programmed to adjust appliance usage patterns based on the current price of electricity.

Electricity Storage

A commonly proposed solution to mitigate the effects of renewable generation variability is the use of electricity storage. There are a number of different technologies that could be used for such purposes, with each technology operating most efficiently over a range of timescales and power and energy levels. An illustration of the effective ranges for different technologies can be seen in Fig. 3.10. There are three basic timescales on which electricity storage is needed, based on response duration: very short duration, short duration, and long duration. Generally speaking, the longer the timeframe is, the higher the associated energy requirements are. These types of storage can also be classified according to their application, where power quality, bridging power, and energy management correspond well to very short, short, and long duration timeframes, respectively [21]. Very short duration storage is needed to respond on the millisecond timescale and provide large amounts of power for a matter of seconds. This type of power is important for power quality and frequency regulation applications. Requiring a response on the multiple second to minute timescale is short duration storage, used for bridging power. This type of storage is useful in the role of generation reserve, and similar applications, to provide power in the event of a system contingency. Very long duration storage can respond on the multiple minute timescale and is used to provide power over long durations, such as those needed for load leveling applications.

While both bridging power and power quality applications are important considerations in integrating variable generation, storage technologies with large rated power output and long discharge times will be the most important for large penetration rates of renewable generation due to their ability to shift energy from times when variable output exceeds demand to those where demand is greater than variable output. Pumped hydroelectricity is one large-scale technology that is applicable for long timescales. During times of excess generation the pumped hydro facility can transfer water from a lower reservoir to a higher reservoir and utilize the potential energy gained during times of high demand. Pumped hydroelectricity storage is somewhat limited by geographic considerations; there must be a fairly large height difference between the two reservoirs, ruling out very flat locations. Compressed air electricity storage is also limited by geographic considerations, particularly for systems with long discharge times. This is due to the fact that very large systems rely on caverns as the compressed air storage vessel. In these systems excess power is used to compress air into a storage area, where it can later be expanded to produce electricity when desired. Current systems use natural gas combustion to supplement the storage compressed air, but designs for future systems need to include this option. Chemical storage in the form of batteries is another possible solution. Lead acid batteries are currently a cost-effective solution, but are also a very mature technology that have relatively low roundtrip efficiency and are limited in grid applications due to their relatively short lifetimes. Sodium-sulfur (NaS) batteries have long cycle life, relatively high efficiency, and are used primarily for grid applications due to the high operating temperatures. A number of other battery chemistries are also available, from those such as lithium-ion that are seen in many other applications where portability is essential, to technologies such as redox flow batteries that are exclusive to large-scale power applications.

Figure 3.11 shows the effect that electricity storage can have on efficient system operation, in terms of reduced wind curtailment, in a theoretical completely flexible system. As may be seen, even a relatively small amount of storage can greatly increase the potential renewable penetration rate by reducing the amount of variable generation that must be curtailed, thus improving the economic viability of additional variable generation capacity. Additional amounts of energy storage can aid in the integration of renewable generation, but provide diminishing marginal returns. Currently electricity storage options are fairly expensive, limiting their potential applications. Even if significant cost improvements in storage technologies are realized, electricity storage should be viewed as but one tool to aid in renewable generation integration.

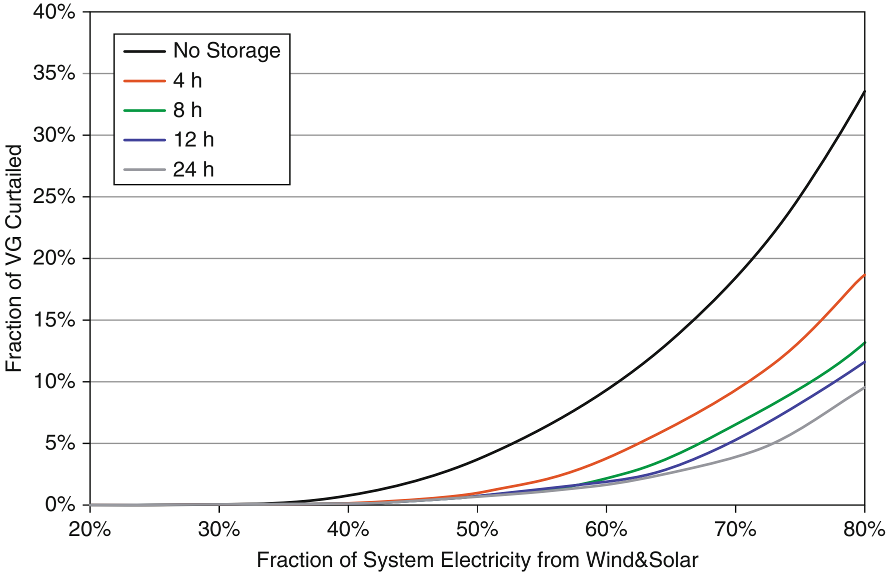


Fig. 3.11 Total curtailment as a function of VG energy penetration for different amounts of energy storage. Assumes 30/70 solar/wind mix, 12 h of storage, and a 100% flexible system. Each hour of storage represents 1 h of average system demand [19]

Renewable Generation Curtailment

Another solution that is occasionally used, even at the current low levels of renewable generation penetration, is production curtailment or spilling. If the production from variable generation is so large that it affects the operation of other units, such as putting baseload production below minimum generation levels, or reaches physical constraints, such as transmission line capacities, then the production can be temporarily halted. While this is a simple solution for small amounts of variable generation, it has its limits of applicability. These are often economic, in that excess variable capacity can be built that will only produce energy at a very small number of needed time points, and will be curtailed during the rest of its possible production times. This would significantly affect the economics of the variable generation plant at very high levels of curtailment, making it economically inefficient to build further capacity unless the load production schedule is expected to be anti-correlated with other variable generation locations.

New Loads

The peak and trough cycle of daily electricity usage requires the use of different types of generation in order to maintain system flexibility. However, the system would be able to operate more efficiently if the daily usage profile was more flat and baseload generators could provide a larger fraction of total energy. This would require sources of new load whose usage patterns coincided with the current nightly trough. In the same vein, since wind power output is generally higher at night, new nighttime loads would allow for less wind curtailment as there would be fewer situations where wind plus minimum baseload generation exceeded the current demand. The most commonly named source of a new load that can serve these purposes is the electric vehicle. Most vehicle usage occurs during the day, leaving vehicles idle during the night. For electric vehicles this provides the opportunity to charge and have their full range capabilities in time for the owner's use in the morning. The charging pattern that the vehicles follow is very important in ensuring that they flatten the load profile, instead of increasing peak loads [22]. To this end, policies must be put in place that can benefit the electricity system without disturbing the benefits that consumers derive from the vehicles, and thus blunting the rate of adoption. One extreme example of a policy intended to derive the most system benefits from the vehicles is the idea of utility controlled charging. In this case the utility would be able to use the vehicles as a form of demand response, perhaps providing an outlet for variable generation that might otherwise be curtailed.

Flexible Generation

The current electricity generation portfolio was not designed with the incorporation of variable generation resources in mind. Very high levels of variable generation penetration will most likely require more flexible accompanying generation, in order to help compensate for the non-dispatchable output. Generator flexibility includes the ability to both start and ramp quickly. For example, current inflexible nuclear and coal plants can require hours to ramp up from a cold start to full capacity. On the other hand, simple cycle natural gas turbines are an example of a unit that can start quickly and ramp from minimum generation levels to full capacity quickly enough to be used to compensate for generator outages. While these flexible units provide the system operator with more dynamic options for meeting the load, they also tend to be more expensive than inflexible baseload plants. However, the current level of system flexibility is not fixed. As older inflexible units reach the end of their operating lives and are retired, new more flexible units can be brought online to replace them. The impact of system flexibility on the integration of variable generation is shown in Fig. 3.12. Here flexibility is represented solely by the combined minimum load levels of all generation units in the system. The ability to integrate variable generation is represented by the amount of available wind generation that must be curtailed as a percentage of the fraction of the total system energy provided by wind power. As may be observed, increased system flexibility causes the amount of wind generation curtailment to drop significantly.

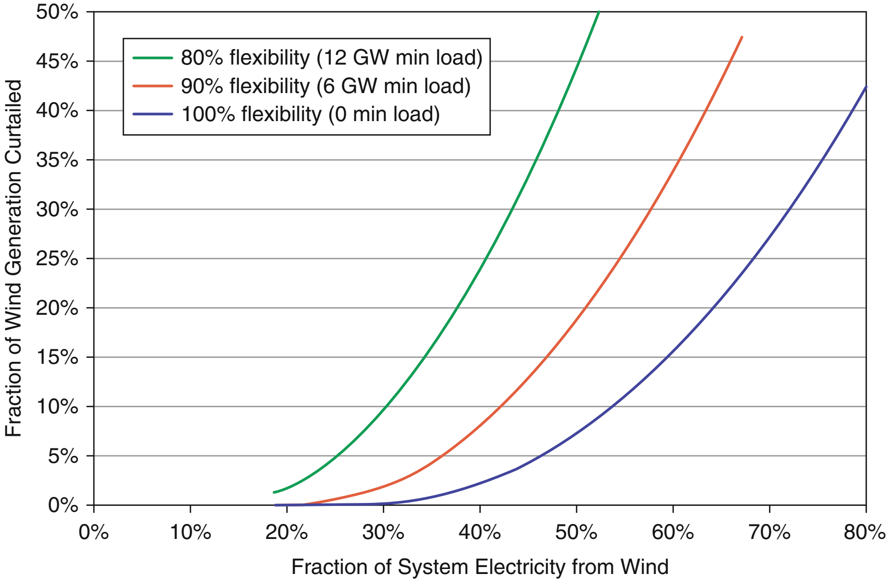


Fig. 3.12 Total curtailment as a function of usable wind energy penetration for different system flexibilities [19]

Future Directions

Variable generation penetration rates are still relatively low (below 10% by energy) in most large systems. At these lower levels variable generation can be fairly easily incorporated into existing electricity system operations. However, if global trends persist very significant penetration rates will soon be reached. At high penetrations of variable generation significant restructuring of current system operations could be necessary to accommodate the additional system variability and uncertainty. As many electricity systems reach penetration rates of between 15% and 30%, methods of economically and reliably integrating variable generation sources will start to be tested on a daily basis. This will quickly bring attention to issues that were not properly considered in previous integration studies. Potential operating issues at higher levels of variable generation must be anticipated before these higher levels of renewable penetration are realized in order to maintain system reliability. The electricity system is such a vital part of daily life that even small changes in the reliability of the system would have far-reaching economic and societal consequences. Further work is required in many areas of renewable generation integration. Resource assessment of wind and solar resources can lead to better decisions on where to site new generation capacity to maximize not only power output, but the benefit to the system. Technological development of generators can both reduce system costs and allow for variable generators to interact more smoothly with the traditional system operation paradigm. Further work on the characterization of variable generators is necessary to understand how systems with large penetration rates will behave. Finally, extensive work is necessary in the area of system operations. Understanding the ability of both supply and demand technologies to increase system flexibility will be critical, as will new ideas on the structure of systems with large amounts of variable generation.

Bibliography

Primary Literature

1. NERC (2009) Accommodating high levels of variable generation. North American Electric Reliability Corporation. The North American Electric Reliability Corporation is the publisher. The report may be found at: http://www.nerc.com/files/IVGTF_Report_041609.pdf
2. IEA (2010) World energy outlook 2010. International Energy Agency, Paris
3. EIA (2011) Electric power annual 2009. Energy Information Administration, Washington, DC
4. Denholm P, Ela E, Kirby B, Milligan M (2010) The role of energy storage with renewable electricity generation. National Renewable Energy Laboratory, Golden
5. GE (2010) Western wind and solar integration study. National Renewable Energy Laboratory, Golden, 536pp
6. Milligan M et al (2010) Operating reserves and wind power integration: an international comparison. The 9th Annual International Workshop on Large-Scale Integration of Wind Power into Power Systems, Quebec, Canada
7. Milligan M, Kirby B (2009) Calculating wind integration costs: separating wind energy value from integration cost impacts. National Renewable Energy Laboratory, Golden
8. Lu X, McElroy M, Kiviluoma J (2009) Global potential for wind-generated electricity. Proc Natl Acad Sci USA 106:10933–10938
9. Schwartz M, Heimiller D, Haymes S, Musial W (2010) Assessment of offshore wind energy resources for the United States. National Renewable Energy Laboratory, Golden
10. de Vries B, van Vuren D, Hoogwijk M (2007) Renewable energy sources: their global potential for the first-half of the 21st century at a global level: an integrated approach. Energ Policy 35:2590–2610
11. Sims R et al (2007) Energy supply. In: Metz B, Davidson O, Bosch P, Dave R, Meyer L (eds) Contribution of working group III to the fourth assessment report of the intergovernmental panel on climate change. Cambridge University Press, Cambridge
12. Chen Z (2005) Issues of connecting wind farms into power systems. In: IEEE/PES transmission and distribution conference and exhibition: Asia and Pacific, Dalian
13. GE (2005) The effects of integrating wind power on transmission system planning, reliability, and operations: phase 2: system performance evaluation. The New York State Energy Research and Development Authority, Albany
14. Wan Y-H (2005) A primer on wind power for utility applications. National Renewable Energy Laboratory, Golden
15. Milligan M, Porter K (2006) The capacity value of wind in the United States: methods and implementation. Electr J 19:91–99
16. Smith JC et al (2010) Impact of variable renewable energy on US electricity markets. In: IEEE power and energy society general meeting, Minneapolis

17. Z-Global (2010) Study of the economic impact of Tres Amigas. Western Electricity Coordinating Council – Transmission Expansion Planning Committee. The Western Electricity Coordinating Council is the publisher. The report may be found at: http://www.wecc.biz/committees/BOD/TEPPC/TAS/MWG/Shared%20Documents/Tres%20Amigas%20Modeling/Z-Global%20Analysis.pdf
18. DESERTEC (2007) Clean power from deserts – the DESERTEC concept for energy, water and climate security. Protext, Bonn
19. Denholm P, Hand M (2011) Grid flexibility and storage required to achieve very high penetration of variable renewable electricity. Energy Policy 39(3):1817–1830
20. Tuohy A, Meibom P, Denny E, O'Malley M (2009) Unit commitment for systems with significant wind penetration. IEEE Trans Power Syst 24(2):592–601
21. Nourai A (2002) Large-scale electricity storage technologies for energy management. In: IEEE power engineering society summer meeting, Chicago
22. Hodge B-M, Shukla A, Huang S, Reklaitis G, Venkatasubramanian V, Pekny J (2011) A multi-paradigm modeling simulation of the effects of PHEV adoption on electric utility usage levels and emissions. Ind Eng Chem Res 50(9):5191–5203

Books and Reviews

Ackermann T (ed) (2005) Wind power in power systems. Wiley, Chichester

Anaya-Lara O, Jenkins N, Ekanayake J, Cartwright P, Hughes M (2009) Wind energy generation: modeling and control. Wiley, Chichester

Blume S (2007) Electric power system basics: for the nonelectrical professional. IEEE/Wiley, Hoboken

Brinkman G, Denholm P, Drury E, Margolis R, Mowers M (2011) Toward a solar-powered grid: operational impacts of solar electricity generation. IEEE Power Energy Mag 9–3:24–32

Burton T, Sharpe D, Jenkins N, Bossanyi E (2001) Wind energy handbook. Wiley, Chichester

Carrasco JM, Garcia Franquelo L, Bialasiewicz J, Galvan E, Portillo Guisado RC, Martin Prats MA, Leo JI, Moreno-Alfonso N (2006) Power-electronic systems for the grid integration of renewable energy sources: a survey. IEEE Trans Ind Electron 53:1002–1016

Corbus D, Lew D, Jordan G, Winters W, Van Hull F, Manobianco J, Zavadil B (2009) Up with wind: studying the integration and transmission of higher levels of wind power. IEEE Power Energy Mag 7–6:36–46

Freris L, Infield D (2008) Renewable energy in power systems. Wiley, Chichester

Grant W, Edelson D, Dumas J, Zack J, Ahlstrom M, Kehler J, Storck P, Lerner J, Parks K, Finley C (2009) Change in the air: operational challenges in wind-power production and prediction. IEEE Power Energy Mag 7–6:47–58

Grubb MJ (1991) The integration of renewable electricity sources. Energ Policy 19:670–688

von Meier A (2006) Electric power systems: a conceptual introduction. IEEE/Wiley, Hoboken

Miller R, Malinowski J (1993) Power system operation. McGraw Hill, Boston

Mills A, Ahlstrom M, Brower M, Ellis A, George R, Hoff T, Kroposki B, Leox C, Miller N, Milligan M, Stein J, Wan Y (2011) Dark shadows: understanding variability and uncertainty of photovoltaics for integration with the electric power system. IEEE Power Energy Mag 9–3:33–41

Shahidehpour M, Yamin H, Li Z (2002) Market operations in electric power systems. IEEE/Wiley, New York

Smith JC, Milligan MR, DeMeo EA, Parsons B (2007) Utility wind integration and operating impact state of the art. IEEE Trans Power Syst 22:900–908

Soder L, Hofmann L, Orths A, Holttinen H, Wan Y, Tuohy A (2007) Experience from wind integration in some high penetration areas. IEEE Trans Energy Convers 22:4–12

Chapter 4
Transmission Blackouts: Risk, Causes, and Mitigation

Damir Novosel

Glossary

DOE	Department of Energy
EMS	Energy Management System
FACTS	Flexible AC Transmission System
FERC	Federal Energy Regulatory Commission
GPS	Global Positioning Satellite
ISO	Independent System Operator
NERC	North American Reliability Council
PDC	Phasor Data Concentrator
PMU	Phasor Measurement Unit
RAS	Remedial Action Scheme
TSO	Transmission System Operator
SCADA	Supervisory Control and Data Acquisition
SIPS	System Integrity Protection Scheme
UCTE	Union for the Coordination of Transmission of Electricity
WAMPAC	Wide Area Monitoring, Protection, and Control
WECC	Western Electricity Coordinating Council

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3

D. Novosel (✉)
Quanta Technology, LLC, 4020 Westchase Blvd., Suite 300, Raleigh, NC 27607, USA
e-mail: DNovosel@Quanta-Technology.com

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*,
DOI 10.1007/978-1-4614-5830-2_4, © Springer Science+Business Media New York 2013

Definition of the Subject and Its Importance

Power system blackouts result in complete interruption of electricity supply to all consumers in a large area. While it may be possible to trace a blackout's beginning to a single incident (e.g., transmission line sagging into a tree), cascading outages are the result of multiple low-probability events occurring in unanticipated or unintended sequence. The likelihood of power system disturbances escalating into a large-scale cascading outage increases when the grid is already under stress.

Blackouts may look like bad luck, but they are result of how the grid is managed. Statistically, a sequence of low-probability contingencies with complex interactions causing a blackout may not happen often but will eventually take place unless measures are taken to prevent it. Presently, some of the grids around the world (e.g., parts of the North American grid) may be susceptible to blackouts as aging and insufficient grid infrastructure may not be adequate to accommodate grid changes, such as renewable generation resources and load growth. Deployment of "Smart Grid" monitoring, control, and protection devices, software tools, and telecommunication infrastructure helps better manage the grid, but does not replace investments in the infrastructure.

Although large-scale blackouts are very low-probability events, they carry immense costs for customers and society in general as well as for power companies. It is easy to misjudge the risks and costs of such extreme cases.

Although widespread outages cannot be completely prevented, their occurrence can be reduced, propagation (size) and consequences arrested, and restoration sped up. In last couple of decades, power systems around the world have been more stressed as the capacity reserves and system margins have been reduced resulting in more blackouts with huge costs to the society.

Introduction

Wide-area electrical blackouts have raised many questions about the specifics of such events and the vulnerability of interconnected power systems [1–4]. Power systems are complex interconnected machines with many components operating in harmony when the system is balanced. When a problem occurs in part of the system, the impact of the trouble may cause to the system losing its balance momentarily. In most cases, the system is immediately isolated and shortly after recovers with no further propagation observed outside of the immediate area.

Exchange of information stemming from the recent worldwide blackout findings and "smart grid" technology innovations shed new lights on the current conditions and needs of power systems. Examination of the root causes, the resulting effects on neighboring systems, and implementation of proven solutions to help prevent propagation of such large-scale events should help in designing and operating reliable "smart grid" and power delivery infrastructures for today and in the future.

Power system professionals can take in consideration the costly lessons of the past, maintain a library of historical lessons about "What and Why it Happened" for the generations to come, and act as catalysts to achieve desired level of power system reliability.

The high cost and the need for extensive mitigation strategies against grid congestions, combined with this type of probabilistic assessments, have led into risk management not focusing on appropriate, cost-effective mitigation actions. From a broader prospective, a misconception may be formed about the grid reliability or its exposure to large-scale outages every so often. It is easy to misjudge the risk of such extreme cases. (Risk is the product of the cost and associated probability, and both factors are very hard to assess accurately.) The high costs of extensive mitigation strategies (e.g., building new transmission lines), combined with inaccurate probabilistic assessments ("blackouts will not happen in my system"), have led to inadequate risk management practices, including not focusing on cost-effective prevention and mitigation initiatives. Such initiatives can provide value through avoidance of huge blackout costs. The following stakeholders benefit from outage/blackout avoidance:

- The society/ratepayers. For example, society costs for August 14, 2003 blackout in the USA and Canada and for August 2006 WECC blackout were estimated at $7B and $1B, respectively.
- The electric utilities, ISOs, generation producers, etc. Costs of service restoration, undelivered energy, cost of litigation, and the negative impact on stock price.

Understanding the complexities of the interconnected power grid, need for proper planning, good maintenance, and sound operating practices are the key to deliver electric power to modern day necessities and prevent the problems of tomorrow's grids. This article offers practical insight on risks and leading causes of widespread blackouts and how best to prevent them to achieve higher levels of grid reliability.

Grid Development History

In the 1930s, electrical power was delivered to consumers around the world by individual, not connected electrical systems. Regional systems have been created next to make power systems more robust and delivery more reliable. The original function of the interconnected systems was to form the backbone for the security of supply and to reach its required high reliability level at reasonable costs. In the 1950s, the power system professionals foresaw the importance of further improving delivery of reliable electricity to consumers. The grid systems have been developed to assure mutual assistance between transmission system participants and/or national subsystems including common use of reserve capacities to optimize the use of energy resources by allowing exchanges between the systems.

Thus, a strategy of interconnecting neighboring systems to improve reliability and security margins became a reality around the world. Coordinated rules for the mutual support of interconnected systems were defined and adopted by the power pool members between power systems, including interconnections among countries (e.g., UCTE in Europe). Since the late 1970s, the electrical transnational infrastructures were exploited more and more for energy exchanges that took advantage of the different production costs of electricity in the various nations or interconnected grids in order to deliver lower cost energy and achieve maximum profits. However, the bulk power system was not originally engineered to transfer large amounts of power between neighboring systems over long ranges but to enable neighboring utilities to support each other during stressed conditions.

In recent years, deregulated energy concepts have created additional burden on the system for using the same conductor for additional capacity increasing already high transfers as new generation sources (including renewable energy) are brought on-line to meet the demand. The high level of power exchanges in today's energy market is technically being provided outside of the scope of the original system design. The higher demand, coupled by low level investments in technology and infrastructure upgrades and capacity increase, has led the Control Area operators to run the system close to the edge, as close to the limits as permitted by the reliability criteria and, sometimes, beyond the limits. At the same time, our increased respect and awareness for the environment and the "Not in My Backyard" sentiments have made it difficult to site transmission lines or major local generation sources, especially in the more densely populated areas, where load is heavy. These difficulties make the system expansions expensive and difficult, and offer new challenges to deliver reliable power.

Recently, major investments have been made worldwide in "smart grid" technologies, e.g., US DOE investment grants. Major motivation for Transmission "smart grid" is in preventing blackouts using Wide Area Monitoring Protection and Control (WAMPAC) technologies, such as synchronized measurements using GPS signals.

There are still isolated power systems around the world (e.g., island networks). Unlike interconnected grids, those power systems do not have flexibility to get help from the neighboring systems to optimally balance generation and load, both during normal and stressed conditions. Those systems are more vulnerable to generation and transmission system outage and require long-term, coordinated planning and investments in the complete electrical grid infrastructure to achieve reliable and cost-effective grid operation and maintenance.

Challenges in Taming the Grid from Wide-Area Blackouts

Evolutions in technology continue to improve all aspects of our lives from precision surgical equipment for use in highly critical operations, to automatic banking anytime of the day, electric rail systems to reduce emissions, and to our home

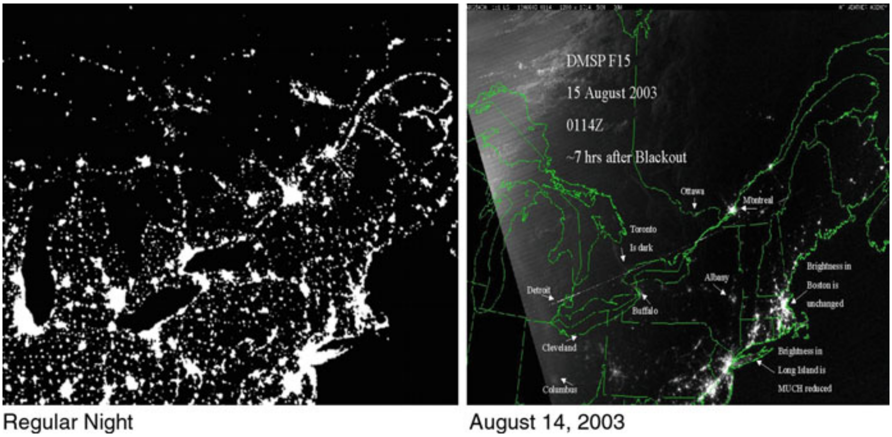


Fig. 4.1 Effects of August 14, 2003 blackout in North America

appliances. Many of the technological innovations have been achieved in recent quarter century and have readily found their way in our daily lives. The modern day amenities and our respect for the environment have also increased our dependency on energy, hence, our expectations for uninterrupted reliable power. However, the demand for availability of power for many of these modern day equipment has not been systematically and uniformly considered. Modern technology is the catalyst driving power delivery demanding grid reliability, and the marked increased dependency on availability has raised the bar on human expectation.

Some of the electrical power systems that experienced blackout in last decade (e.g., North America, Europe) are among the most reliable systems worldwide. However, they are subject to a host of challenges – aging infrastructures, renewable and distributed energy integration, transmission and distribution grid expansion to meet the growing load demand and transfer renewable energy to load centers, etc. Figure 4.1 shows impact of the 2003 blackout on supplying power to the consumers (before and after the blackout).

After some major blackouts worldwide in the last 2 decades, utilities have hardened their electrical systems, and regulatory organizations (e.g., NERC and FERC and state regulators in the USA) have focused on defining and enforcing reliability standards. This has resulted in better planned, operated, and maintained grid. However, one of the challenges facing the electric industry today is the balance between reliability, economics, environmental, and other public purpose objectives to optimize transmission and distribution resources to meet the demand. Resources and transmission adequacy are necessary components of a reliable and economic supply. Though the reliability and market economics are driven by different policies and incentives, they cannot be separated when the objective is reliability and availability. Today, grid planning in the regional and interregional environment faces an extremely difficult task given the challenge to achieve resource adequacy in today's restructured industry, where market economics, local concerns, and renewable energy resources often derive the decision for generation facility siting remote from major load centers. Equally difficult is planning for an adequate transmission system when the location of future generation facilities is uncertain and the lead time for transmission construction is very long (just the permitting process may take several years).

It is more important than ever to find ways to project transmission and distribution growth, solutions to deploy, and criteria to be applied to guide prudent investment decision. Some of the key areas to address are the following:

- Integration of renewable energy – As renewable resources (e.g., wind and solar) are located far from the load centers, additional stress was put on the system, causing higher vulnerability to outages.
- Price for reliability – Costs and risks transmission owners and customers are willing to assume. The power industry is accustomed to optimize investments and evaluate return on investments based primarily on financial aspects of trading energy and serving load within certain reliability criteria. This is often done without considering financial aspects of unavailable energy (undue service interruptions) due to low reliability and slow restoration that incurs significant costs to the society. This is an incomplete financial model that results in suboptimal investment strategies.
- Large regional geographic areas should be included in the scope of transmission planning and decision-making. However, when assets need to be built, it is not easy to identify true beneficiaries and how costs are to be shared.
- Quick restoration – As it may not be possible to completely avoid outages, it is required with today's technology to reduce power restoration.

Electricity is the key resource for our society; however, strategic planning (regional and national) requires additional priority to improve system reliability.

History and Examples

Within the last decade, the number of wide-area outages has rapidly increased (blackouts in north-east USA and Canada, western USA, Brazil, Italy, Sweden, Denmark, England, India, Malaysia, Australia, New Zealand, Greece, etc.) affecting over 300 million customers worldwide. As the likelihood of low-probability events escalating into a cascading outage increases when the grid is already under stress due to preexisting conditions, one can conclude that power grids are more prone to disturbances than ever.

History has showed that both unscheduled and scheduled (regular maintenance) outages have affected power system's balanced operation hence signifying the grid complexity during managed conditions [1, 2, 5–7]. In the case of the August 1996 North America disturbance that affected 12 million people [5], a series of equipment were being removed for maintenance in parts of the Western grid when the weather was moderate, yet these pieces of equipment were needed to support transfers in other parts of the Western grid, which was experiencing extremely high temperatures.

Analysis of the 2003 incident in the north-eastern part of the USA [6], which affected 50 million people, revealed that a series of cascading events over the course of several hours, rather than a single instantaneous problem, initiated the major disturbance phenomenon that toppled the large part of the US Eastern Interconnection. The blackout itself was preceded by scheduled generation outages and line tripping caused by overgrown trees in the right-of-way. It was accompanied by failures of EMS/SCADA alarm systems, which prevented operators from diagnosing problems. The initial line disconnection caused another 345 kV line to overload and sag into a tree, resulting in remaining 345 kV lines to disconnect. Underlying 135 kV lines overloaded and disconnected, followed by tripping of generating units, causing a part of the system to go black. A lack of communication and coordination between utilities and ISOs involved exacerbated the problem. The grid was restored in 1–2 days (depending on the area affected and ability to get generators back on line).

The September 2003 disturbance in the connected European grid affected 57 million people. Several 220–400 kV lines were out of service for maintenance reasons prior to the event occurrence. Italian grid was importing 6 GW from the rest of the grid. One of the 380 kV lines disconnected due a tree contact. The parallel line overloaded, and although the import was reduced, it was not enough to prevent sagging into a tree and disconnecting. Other lines to Italy overloaded and tripped, resulting in isolating Italian grid 12 s after the loss of the second line. During those 12 s, low voltage in northern Italy caused generators to disconnect. Other countries tripped generation (app. 6.7 GW). In summary, 2.5 min after islanding, Italy goes black separated from the rest of the grid. However, unlike the blackout in the USA, it took only 5–9 h to restore the power to major cities. Main reasons are for faster restoration was type of generation that was able to get back on line faster and accompanying restoration processes (e.g., so-called black-start capabilities allowing fast generation reconnection).

The most severe disturbance in the history of UCTE considering number of Transmission System Operators (TSOs) involved happened in October 2006 [7] when system separated in three islands. Following were key reasons for the disturbance:

- N-1 criterion (planning criteria so that a single equipment outage does not create a system disturbance) was not fulfilled as wind generation was not adequately predicted. Large wind storms increased production in northern Germany.
- Inappropriate inter-TSO coordination and training. The time of the planned line outage was changed, and new conditions were not checked.
- Uncoordinated protection settings on both sides of the critical line.
- Uncoordinated operation of wind generators.
- Inadequate coordination of restoration.

All the above blackouts included combination of phenomena such as line overloads, voltage and angular instability, and system separation. Those blackouts have served as catalysts in propelling the power industry toward analyzing blackouts and finding solutions to prevent such occurrences. The 1994–1996 blackouts in the western part of North America resulted in formation of investigating teams which ultimately made a combined list of 130 conclusions and 54 recommendations [7]. The August 14, 2003 investigating teams identified 60 recommendations (14 by North American Reliability Council, or NERC, and 46 by the US Canadian Task Force) [6]. The Union for the Coordination of Transmission of Electricity (UCTE) identified 14 observations for the September 28, 2003 outage, very similar to those identified for the outages in North America that happened just a month before. Although major improvements have been accomplished after the blackouts in corresponding grids, the similarities in findings among those blackouts prove that if recommendations had been used among grids, the impacts of the outages could have been minimized [4].

By some accounts [8]:

- These kinds of outages are consistent with historical statistics, and they will continue to happen. Some may compare blackouts to events such as long-term weather forecasting (hurricane and mudslides) or to natural disasters such as earthquakes as being difficult to predict and/or to prevent.
- The more immediate problem may be the industry's investment of less than 0.5% in R&D, one of the lowest rates for any industrial sector.
- A power system is composed of hundreds of thousands of pieces of equipment from bulk autotransformers, high-voltage transmission systems, to a light bulb. It has been suggested that one could not get a computer big enough to model a complex system as, for example, the Eastern Interconnection and perform the planning studies.
- Large blackouts occur because the grid isn't forcefully engineered to prevent them. Purposely weakening the grid can reduce large blackouts but would increase the frequency of smaller ones.

Chifong Thomas, formerly transmission planning engineer from Pacific Gas and Electric Co. points out that if large blackouts occur anyways, as they are hard to predict as earthquakes, then nothing anyone could do would make any difference. This contradicts the premise that industry underinvestment in R&D is the immediate problem. If the first premise is true, the second one is irrelevant. She also points out that if the grid planning is done comprehensively and correctly, then operators with proper training should have time to respond to contingencies and/or to limit the impacts of the contingency.

Dr. Mayer Sasson, principal advisor of Electric Markets Policy Group at Consolidated Edison Co. of New York, highlights the vulnerability of the interconnected grid by pointing out that it may take only one member of a control area to be operating outside of the reliability limits for any reason, including unintentionally, to cause a cascading outage that can quickly propagate to neighboring interconnected system control areas. This underscores the criticality of complying with mandatory reliability rules.

Dr. Bogdan Kasztenny, power system protection and control application manager at Schweitzer Engineering Laboratories, raises the important issue of human factor involvement in the last few critical hours before any major event. "Even in a poorly designed and under-invested system, operators could sometimes salvage an event that seems to be disastrous, or collapse an otherwise quite secure situation in a strong and reliable system. It is not so with earthquakes. Power systems are man-made creations run by humans. Operational procedures, availability and accuracy of real-time information, adequate training including dry runs on simulators are technical means that improve response of the operators."

Kasztenny emphasizes that the power system is a complex generating, transmitting, and distributing system for a medium that cannot be stored, or buffered, in the reality of very limited redundancy. This makes it quite different from the banking, phone, or similar systems. Other systems are subject to brownouts. However, the power system must balance the medium under physical constraints and is therefore subject to collapse if the constraints are violated.

Pre-outage Conditions and Risks for Blackouts

The grid is a tremendously complex system, and the interconnections that allow us to benefit from higher reliability and lower costs also cause the domino failures experienced in many parts of the world in recent years. Although there is a tendency to point at one or two significant events as the main reasons for triggering cascading outages, major blackouts are typically caused by a sequence of low-probability multiple contingencies with complex interactions. The three "Ts" – Trees, Tools, and Training – have been identified as the leading focus areas to prevent widespread outages not caused by natural events. However, disturbances have occurred following extremely low-probability successive unscheduled equipment outages beyond planning criteria. There have also been cases of system disturbances caused by scheduled equipment outages when the electrical system has not been adjusted, for continued safe operation, prior to the equipment being removed. Low-probability sequential outages are also not anticipated by system operators, thus rendering the power system more susceptible to wide-area blackouts. As the chain of events at various locations in the interconnected grid unfolds, operators cannot act quickly enough to mitigate the fast developing disturbances.

Power systems are engineered to allow for reliable power delivery in the absence of one, two, or more major pieces of equipment such as lines, transformers, or bulk generation, commonly referred to as contingency conditions. For example, after the 2003 blackout in North America, North American Electric Reliability Council (NERC) set forth the reliability standards and performance requirements that are enforced by audits. However, the complexity of the grid operation makes it difficult to study the permutation of contingency conditions that would lead to perfect reliability at reasonable cost. Accurate sequence of events is difficult to predict, as there is practically an infinite number of operating contingencies. With system changes, e.g., independent power producers selling power to remote regions, load growth, new equipment installations that cause significant changes in power flow to name a few, these contingencies may significantly differ from the expectations of the original system planners and engineers.

The likelihood of power system disturbances escalating into a large-scale blackouts increases when the grid is already under stress due to preconditions. Those preconditions are summarized as follows:

- Congested grid with tight operating margins
  - Not building lines or generation as fast as required, exacerbated by difficulty in identifying business models to recover costs, and a cumbersome permitting process
  - Not well-planned wholesale merchant transactions with scheduled transactions not changed to allow for transmission relief when required
- System stress caused by intermittent renewable energy and/or suboptimal operating practices
- Insufficient reactive support where and when required to maintain required voltage levels
  - Adequate dynamic reactive power is required close to the load as reactive power cannot be transferred over long distances
- Uncoordinated planning between transmission and generation
  - Inadequate system reserve, such as generation spinning reserve
- Inadequate planning/operation studies
  - No routine use of an effective contingency analysis tool
  - Uncoordinated interregional transmission planning
- Aging infrastructure, prone to failures, accompanied by insufficient level of investment in maintaining the grid
  - It is more and more difficult to isolate and remove equipment for maintenance
- Both scheduled and uncoordinated maintenance
- Lack of system and component knowledge (e.g., system operator not aware of line loading margins)
- Inadequate right-of-way maintenance or environmental policies versus right-of-way vegetation management
- Weather (high temperatures; wind, thunderstorm, fog, etc.)
- Regulatory uncertainty
- Inadequate Automatic Warning, Protection, and Control Systems

In general, combination of various factors makes power systems more susceptible to disturbances.

Symptoms of Blackouts

It is the cascading events that cause disturbances to propagate and turn into blackouts. System is stressed and as system and equipment faults occur, the chain of events starts. For example, some generators and/or lines are out for maintenance, line trips due to a fault. Other lines get overloaded, and another line gets in contact with a tree and trips. There is a hidden failure in the protection system (e.g., outdated settings or HW failures) that causes another line or generator to trip. At that stage, power system is faced with overloaded equipment, voltage instability, transient instability, and/or small signal instability. If fast actions (e.g., load shedding, system separation) are not taken, system cascades into a blackout.

Evaluation of disturbances shows that protection systems have been involved in 70% of the blackout events [9]. For example, distance relays trip on overload and/or low-voltage sensitive or ground overcurrent relays trip on high unbalance during high load. Inadequate or faulty alarm and monitoring equipment, communications, and real-time information processing can further exacerbate disturbances in the system. Either information is not available or operators are flooded with alarms, so they cannot make proper decisions fast.

Human error and slow operator response are major contributing factors for cascading outages. As a disturbance develops, operators in various regions are faced with the questions "is the best course of actions to sacrifice own load, cut interties, or get support from neighbors?," "should we help or should we separate?." Important aspect in designing connected power systems is that individual systems should not allow cascading outages to spread throughout the system.

There are a number of other contributing factors that allow a blackout to spread, including lack of coordinated response among control areas. If each region focuses primarily on its own transmission system, the total connected system may not be reliable. As it is very difficult for operators to decide on best actions during a fast developing disturbance, it is desirable to take automated actions before system separates or to separate it in a controllable manner.

Generally, disturbance propagation involves a combination of several phenomena:

- Equipment tripping due to faults or overloads (e.g., transmission lines and transformers). These events may cause other equipment to get overloaded, creating a cascading event contributing further to system-wide outages.
- Power system islanding (frequency instability) when power system separates. Islands are formed, with an imbalance between generation and load, causing the frequency to deviate from the nominal value, leading to additional equipment tripping.
- Loss of synchronous operation among generators (angular or out-of-step instability) and small signal instability that may cause self-exciting inter-area oscillations if not damped.

Table 4.1 Types of wide-area events for different transmission systems

System config.	Densely meshed power system with dispersed generation and load		Lightly meshed transmission systems with localized generation and load	
Events	Located in a large interconnection	Not interconnected or by far the largest partner	Located in a large interconnection	Not interconnected or by far the largest partner
Overloads	**	**	*	*
Frequency instability	*	**	*	**
Voltage instability	*	*	**	**
Transient angle instability	*	*	**	**
Small signal stability	*	*	*	*

*Phenomena did not affect a particular grid configuration in the past, but have affected modern grids
**Major phenomena in a particular grid configuration

- Voltage instability/collapse problems that usually occur when the power transfer is increased and voltage support is inadequate because local resources have been displaced by remote resources without the proper installation of needed transmission lines or voltage support devices in the "right" locations.

Table 4.1 shows the types of wide-area disturbances likely to occur in two different types of interconnected power grids, namely, meshed network versus an interconnected transmission system of narrow corridors consisting of extensive generation tied to the interconnection [10]. One star indicates that those phenomena did not affect a particular grid configuration in the past, but have affected modern grids. Two stars indicate major phenomena in a particular grid configuration.

The characteristics of the power system influencing the types of mitigation methods have been described in a variety of literature [1–4, 9–13]. The relative time of action for different type of events, from normal to extreme, varies depending on the type and speed of the disturbance and the need for coordination. Example of the time line for different type of events is shown in Fig. 4.2.

Deployment of a well-coordinated overall defense plan to prevent blackouts requires implementation and coordination of various schemes and actions, spanning different time periods. When events can be controlled to result in gradual shutdown of the available resources rather than permitting them to cascade, their impact could be minimized. A practical approach to identifying stressed system conditions, which are symptomatic of cascading, is feasible. This can be done by defining and modeling the power system parameters considered for reliable operation such as voltage, frequency, or phase angle at critical locations. Such findings can then be implemented through investments in Hardware equipment and Software tools that help manage the grid more effectively.

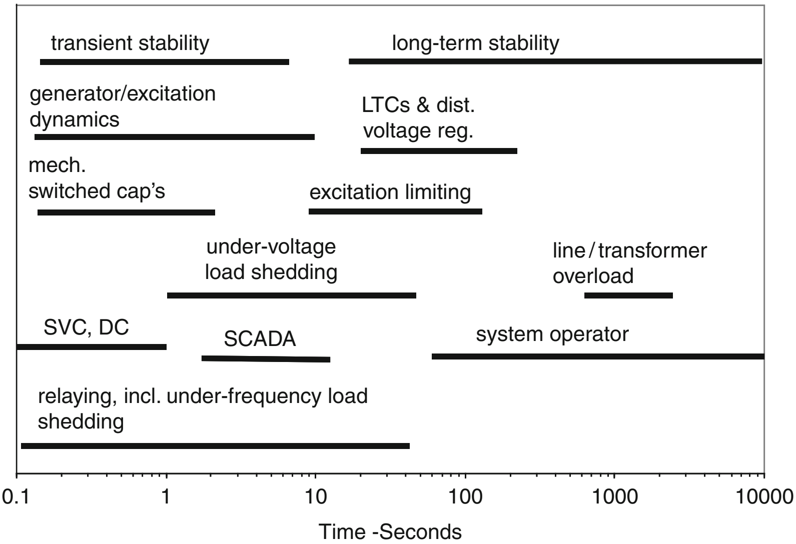


Fig. 4.2 Some time frame factors of power system dynamics

Power System Modeling and Analysis

Electrical grids have been characterized as the most widespread interconnected, complex, dynamic systems made by humans. A power system carries tremendous amount of electricity that all depend on. Although blackouts are difficult to predict and prevent, the notion that it is not possible to simulate the grid behavior, to identify and address most vulnerabilities, is not accurate.

Carson Taylor, power system simulation expert (formerly with Bonneville Power Administration), confirms that today's technology allows for detailed modeling of complex power systems. Taylor emphasizes that the Eastern Interconnection has been simulated in great detail with 40,000+ bus models. Simulations with 100,000+ models are feasible. Feasibility increases with IT advancements. Computation is not a large problem. Computation is scalable by parallel computation on multiple servers; cases can be farmed out to the multiple servers. Simultaneous processing method is used for energy management system dynamic security assessment.

Professor Göran Andersson, Eidgenössische Technische Hochschule (ETH) University in Zurich and a noted expert in power system dynamics, concurs with Taylor and brings up an important issue that the challenge is not technical, i.e., modeling or computer capacity related; rather it is the data management and proper interpretation. Professor Andersson also underlines that the "Statistical methods can give some information and insight concerning the sizes and frequencies of blackouts, which is of value. However, the problem is the calibration of the frequency scale, since this requires a detailed modeling of the interactions.

The statistical insights, however, do not provide to any large extent the guidance to avoid blackouts to the power system professionals operating the systems. In terms of modeling, the details of the system and the interactions between different components and subsystems are indispensable."

Both Andersson and Taylor emphasize that best practice is to continually improve and update models and compare simulations with real power system response. This is not unique for power systems and is continuously being done in the industry and academia. In addition, much progress has been made over the years, and even if predictions from simulations are problematic, efforts to model, simulate, and validate performance provide invaluable insight for a reliable power system operation.

In conclusion, the power grid can be modeled and studied; however, as there is an infinite number of contingencies that can occur and the current state is not precisely known, it is not possible to exactly predict disturbance propagation far in the future. However, innovations in power system tools from planning, to monitoring, to operation are strategies that would help in meeting the challenges of the twenty-first century expectations in reliable power delivery.

How Disturbances Turn into Blackouts

It has been demonstrated time and again that wide-area blackouts are caused by operation of the interconnected power system outside of the operating limits or for operating conditions that have not been thoroughly studied. As described by Vahid Madani, principal engineer at PG&E, one of the ways to understand the challenges of power delivery is to liken it to driving the highways via motor vehicle. As motor vehicle operators, most of us have experienced a wide variety of unplanned difficulties and challenges slowing down our travels. In many ways, widespread outages have similar characteristics as a highway traffic gridlock. Some of the key aspects of traffic jams include the following:

- Not enough lanes to accommodate the growing demand.
- As one or two lanes are closed, the traffic flow is significantly impacted, and in the most severe case, it causes a complete highway shutdown. A circumstance out of control of those not involved with the accident, yet they are stuck (blackout).
- A properly designed system would include major alternate freeways that are easily accessed through proper detours to minimize impact from the gridlocks.
- Repair of the old highways may not be enough to solve traffic congestion. At times prudent investments in building new traffic lanes, or completely new thruways, and innovative traffic control systems are needed.

Dr. Daniel Karlsson, system analysis and protection expert from Sweden, also compares the expansion of highway traffic with an expansion of the power grid as both have grown from minor systems to extremely important infrastructures in the same time period and both continue to grow. However, he points out that the public accepts a much higher degree of failures (e.g., people seriously injured or worse) due to automobile traffic than they accept a widespread power outage, demonstrating the important role of electricity in our daily lives and hence the criticality of reliable power delivery.

> Karlsson brings up a historical perspective to explain how the large interconnected power systems of today have been formed due to constant demands on capacity, economy, and reliability. He points out that initial power systems were small grids with low capacity and low reliability. Extensions emerged as dictated by capacity needs. To improve reliability of the individual systems by allowing support from the neighbors, these systems were interconnected. New phenomena appeared, such as transient instability, resulting in studies and actions to counteract them. Complex powerful power systems introduced new transmission capacity problems and actions to counteract them (series capacitors inserted in the transmission line, shunt capacitors and reactors, automatic tap changers to control transformer voltage, etc.). This consequently brought new phenomena like sub-synchronous resonance and voltage instability and, again, a need for new studies and equipment, such as Flexible AC Transmission Systems (FACTS), High Voltage DC (HVDC) links. Dr. Karlsson emphasizes that the complexity of the present power system, and factors such as environmental and rights of way, governmental, cost-to-benefit evaluation for large scale investments will derive us to maximize the use of current assets without truly addressing the rising demand for new infrastructure. This trend will continue to challenge the industry with new technology and actions: superconductivity, energy storage, micro-grid, etc.

There is also a strong relation between system size and reliability. In the ever growing demand to be supported by the power system, our industry tends to push the limits challenging the reliability with a question, "where is the edge?" This is particularly true in many places such as North America, where the expansion efforts are not growing as much, or as rapidly as, the grid is being utilized.

It is noted that weakening or splitting the grid on purpose during normal operation is not a sound alternative, as this strategy would make a full circle for the grid. For example, by operating the power grid in separate islands, one could easily weaken the power system. That would effectively mean coming back to the original design of the small grid with low capacity. Separating the grid into islands would also impact deregulation, e.g., each DG would be selling power to its own neighborhood. The small utility will soon need occasional support for reserve margin, voltage, and reactive margins from neighboring systems, hence, back to the interconnected grid. The solution is not in separating the grid into islands, rather to resolve transmission problems to mitigate potential for widespread cascading outages.

Chifong Thomas dismisses the argument that large blackouts occur because planning engineers spend too much time preventing small blackouts. She argues that this theory ignores the fundamental fact that large blackouts start out as small problems that do not by themselves necessarily lead to blackouts. They lead to blackouts when small problems are not corrected in time.

Professor Vijay Vittal, Iowa State University, corroborates that the impact of such severe system failures could be mitigated by several approaches such as use of corrective controls or performing more effective analysis closer to real time.

The effective way to minimize disturbance propagation is to truly understand the common causes and design the appropriate solutions. The system needs to be addressed as a whole, implementing various planning, operations, maintenance, and regulatory measures in a coordinated way.

A possibility to prevent propagation of the disturbance throughout interconnected grid, but not weaken the grid during normal operation, is to design the interconnected power system to allow for intentional separation into stable islands or interrupt small amounts of load only when the system experiences major disturbances. As operators may not be able to act fast enough to take into account all data related to the on-line state of the system, separation actions should be done automatically. System Integrity Protection Schemes (SIPS) are wide-area automatic schemes that are designed to detect abnormal system conditions and initiate pre-planned automatic and corrective actions based on system studies [10–13]. They are also referred to as Special Protection Schemes (SPS), or Remedial Action Schemes (RAS). They detect abnormal wide-area system conditions and trigger automatic actions to restore acceptable system performance. The initiating factor in implementing significant number of SIPS in the western part of the USA (WECC) has been to better protect the system against multiple contingencies, particularly after the 1994 and 1996 blackouts [7]. Designing the grid with appropriate measures for voltage control and advance warning systems such as wide-area protection and control would allow for both strong interconnected grids during normal operation (to make system more reliable and secure) and creation of predetermined islands only when necessary.

In conclusion, instead of weakening the grid, power industry needs to address deregulation as one important aspect in understanding the underlying causes of system-wide outages. The bulk power system was often not originally designed to transfer large amounts of power between neighboring systems. Individual power systems were interconnected to improve electrical network reliability by enabling neighboring utilities to support each other during stressed conditions. In recent years, deregulation has imposed additional requirements of high transfers from new generation sources to the load areas. At the same time, public pressures and the "Not in My Backyard" sentiment make it difficult to site transmission lines or major local generation sources, especially in the more densely populated heavy load areas, making the system expansion very expensive and difficult. In addition, recent disturbances have, more and more, been accompanied by voltage stability problems.

In summary, following are the main reasons for disturbances to turn into blackouts:

- Inability to prevent sequential tripping due to overloads, power swings, and voltage fluctuations
- Inadequate or faulty EMS/SCADA system (incl. alarm burst) – need for reliable alarm filtering, proper visualization, and analysis tools
- Protection miss-operation or unnecessary actions
  - Incorrect settings, e.g., impedance-based protective devices tripping on overloads (NERC developed regulations after the 2003 blackout to address it)

  - Hidden failures: uncovered application design flows or HW failures
  - Inadequate design, e.g., application of impedance-based protective devices without the out-of-step blocking

- Inability of operators to prevent further propagation of the fast-developing disturbance
- Lack of coordinated response during developing disturbances, e.g., joint procedures between ISOs to deal with the problem quickly and effectively
- Generators tripping too early – generator tripping to be coordinated with the rest of the system

Blackout Prevention

The alarming increase in the number of major blackouts requires exploring new frontiers in deployment of well-defined and coordinated overall plans (planning, operations, and maintenance). As analysis of recent disturbances reveals some common threads among them, the conclusion is that propagation can be arrested and impact of disturbances reduced if knowledge gained is properly utilized [1–4].

The best way to minimize wide-area power system disturbance is to understand the leading causes. Study of blackout history in the past decade shows that in each case the reliability standards have been violated in some form or fashion demonstrating the priority for more stringent compliance enforcement of the standards, necessity to invest wisely in new transmission facilities that expand the reliability parameters of the grid in the “right” areas, new grid monitoring technologies, and especially the tools that help us make it simpler to manage the day-to-day operation.

Electric reliability and efficiency are affected by four segments of the electricity value chain: generation, transmission, distribution, and end use. Satisfactory system performance requires investments in all these segments of the system. Increasing supply without improving transmission and distribution infrastructure in the right locations, for example, may actually lead to more serious reliability issues.

The retirement and replacement of transmission equipment at the end of its useful life will be another important remedy for increasing failure rates and potential outages in the future. Aside from the aging infrastructure concerns, the transmission grid must be upgraded and expanded to continue to meet the growing demands. For example, high-voltage power electronic devices allow more precise and rapid switching to improve system control and to help increase the level of power transfer that can be accommodated by the existing grid. Distributed energy technologies, if properly applied, could also play a role in relieving power flow demands on the transmission networks. In conclusion, while the new investments shall certainly include some new transmission lines, it will also encompass power delivery technologies such as series capacitors, single-phase operation of transmission lines, FACTS, HVDC links, energy storage, superconducting materials, and micro-grids.

The legislative and governmental commitments to build infrastructure, compliance with reliability requirements, and state, regional, and interregional plans are required to achieve the sustainable grid. Measure such as computerized control and data acquisition, phase-shifting transformers, coordination mechanisms, and electronic data exchange between operators are also some alternatives that improve the capability of the existing infrastructure and allow for a more robust power exchange.

Furthermore, reliable power system performance requires a balance of many critical components such as adequate reserve real and reactive power margins, reliable real-time telemetry and status monitoring, real-time state estimation, properly set, maintained, coordinated, and tuned protection and control systems, etc. Academic, industry, and governmental initiatives are required to set and enforce the standards for voltage control and reactive power practice, to improve system modeling and validation process, to enhance operator-training curriculum, and to assure that operators are assigned responsibility to take actions to prevent disturbance propagation.

In terms of modeling, quantitative analysis is needed to validate models of generators, turbines, and the associated controls to match actual system oscillations and damping. Likewise, dynamic loading or stability impact on protection devices (designed to operate for faulted conditions, e.g., tree contact) should be considered, and routine protection coordination studies using accurate model should be regularly performed. There are also concerns associated with protection and control application and settings when short-term market conditions for power transfers stress the equipment resulting in a risk of equipment outage.

Tools that improve real-time system monitoring, evaluation, visibility, security, congestion tracking, control, visualization, and information sharing about grid conditions over a wide region will allow operators to manage the grid more reliably on a day-to-day basis as well as in emergencies. Poorly recognized dynamic constraints can unnecessarily narrow operating limits and endanger reliability. Real-time security analysis tools are becoming increasingly critical for daily operation to visualize critical stability boundaries and to determine stability operating limits based on actual conditions.

Finally, the recent large-scale generation trips and remedial action responses have provided some very good benchmarks for combined small and large-scale analysis. Reexamination of traditional planning, operating, system design, protection applications, and device settings will help improve system response to slow or limit the spread of cascading outages. The frequency and varying impact levels of worldwide blackouts have provided the power industry with opportunities and supporting information to:

- Study the complex power system phenomenon to minimize propagation for future system-wide events using accurate and user friendly tools
- Validate the system studies against actual power system performance and governor modeling data

- Environmental and political factors limiting new addition of generation and transmission capabilities. Highlight the needed support for regulatory measures to ease wise grid expansions, grid reinforcements, and well-established and measured reliability enforcement process
- Operating capacity reserves and margins for transmission flows must remain available to allow system adjustments during unintended multiple contingency conditions. Enforce reliability requirements, for example, Planning Standards for Normal and Emergency Conditions
- Visit existing operating practices and real-time data exchange policies among control areas
- Make use of enhance maintenance practices and asset management tools
- Timely deploy Special Integrity Protection Schemes (SIPSs) to prevent spreading of the disturbance

Furthermore, protection systems are usually involved in major wide-area disturbances, sometimes preventing further propagation, and sometimes contributing to the spread of the disturbances [14]. A very important lesson is that the design and operation of conventional protection and control schemes have to be scrutinized assuming stressed conditions. Improvements to existing protection systems can help prevent cascading and minimize the impact and number of wide-area disturbances. In general, a protection system should operate only for its designed conditions. Preventing further disturbance propagation should be achieved by designing and setting protection, and control schemes do not miss-operate during major disturbance conditions. However, some experiences include relay operations that prevented further cascading by tripping on system conditions for which they were not designed.

Some key opportunities for improvement include coordinated adaptive protection and control systems and wide-area monitoring with advance warning systems, as elements of WAMPAC. The advance technology today promotes the concept of the "smart grid" – an integrated, electronically controlled power system that will offer unprecedented flexibility and functionality, and improve system reliability. The concept of the smart power delivery system includes automated capabilities to recognize problems, find solutions, and optimize the performance of the system.

In summary, corrective and preventive actions to avoid wide-area blackouts are the following:

- Provide operator with:
  - Tools to measure, monitor, assess, and predict both system performance and the performance of market participants
  - Training, incl. coordinated approach among control areas and use of dispatch training simulators
- Improve monitoring and diagnostics and control center performance
  - Availability of critical functions needs to be 99.99%
  - Assure adequate exchange of information between neighboring control centers

  - Secure real-time operating limits on a daily basis
  - Shared and consistent rating information required

- Use dynamic line ratings ambient temperature, wind, pre-contingency loading, etc., to better understand what the actual system margins are
- Better utilize available and standby generation in the area; implement black-start capabilities
- Improved maintenance and condition assessment of aging infrastructure
- Improve vegetation management
- Accurate generator, dynamic load, and reactive support device models, including renewable generation models
- Advanced algorithms and programs to assist the operator, such as "faster than real-time simulations"
- Protection coordination studies across regions and in coordination with equipment control and protection

  - Study and review protection designs on a regular basis, as system conditions change
  - Assure planned relay operation (e.g., distance relays not to trip on out-of-step and overload; ground overcurrent relays not to trip on high unbalance during high load, coordinated zone 3 operation, etc.)
  - Avoid hidden failures by adequate testing of not only individual relays but also overall relay applications
  - Increase the security of protection design in the areas vulnerable to blackouts

- Deploy Wide Area Monitoring, Protection, and Control (WAMPAC) systems to improve grid visibility and initiate corresponding actions

In conclusion, it is important to take a balanced approach to fixing the system as a whole by implementing various planning, operations, and maintenance measures and weighing the costs, performance impacts, and risks associated with each measure. One needs to evaluate how to operate and maintain the power system for the years to come to meet defined reliability objectives. There is no silver bullet solution to preventing blackouts, but there are general measures than can and should be taken to minimize impact of wide-area disturbances.

Each entity needs to focus on further process improvement, standardization, and better asset utilization, all parts of overall asset management strategy. This is the key to increased reliability and to protecting investments. Prudent capital investment in power system infrastructure has to be based on stringent cost-benefit analysis to optimize investments. For example, increase in generation ("conventional" or renewable energy) has to be planned in conjunction with strengthening the transmission grid. Holistic, multi-year system planning is required to achieve efficient, reliable, and cost-effective grid. In addition, independent certification of technical systems and business processes can be an important element of assuring that proper actions are taken, processes implemented, and investments made.

System Integrity Protection Schemes

Examples of large blackouts in the past decade have shown that the risk of large blackouts is no longer acceptable and can lead to very large and unexpected social and financial consequences. Reduction of the risk of large system-wide disturbances and blackouts requires that system protection function be approached with the assistance of modern technologies in support of preserving system integrity under adverse conditions.

These schemes, defined as System Integrity Protection Schemes (SIPS) [10–13], are installed to protect the integrity of the power system or strategic portions thereof, as opposed to conventional protection systems that are dedicated to a specific power system element. The SIPS encompasses Special Protection System (SPS), Remedial Action Schemes (RAS), as well as other system integrity schemes such as Underfrequency, Undervoltage, Out-of-Step, etc. These schemes provide reasonable countermeasures to slow and/or stop cascading outages caused by extreme contingencies.

SIPS goal is to prevent propagation of disturbances for severe system emergencies caused by unplanned operating conditions and ensure system security. They stabilize the power system for equipment outages, N-2 (two key elements out of service) or beyond by:

- Preventing cascading overloading of the lines and transformers
- Arresting voltage decline
- Initiating pre-planned separation of the power system

Advanced detection and control strategies through the concept of SIPS offer a cohesive management of the disturbances. With the increased availability of advanced computer, communication, and measurement technologies, more "intelligent" equipment can be used at the local level to improve the overall response. Traditional dependant contingency/event-based systems could be enhanced to include power system response based algorithms with proper local supervisions for security.

The IEEE Power System Relaying Committee has developed a worldwide survey on SIPS [12]. Figure 4.3 shows a summary of the overall SIPS purpose

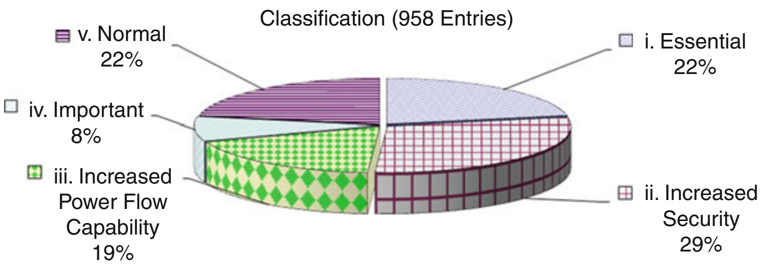


Fig. 4.3 SIPS classification

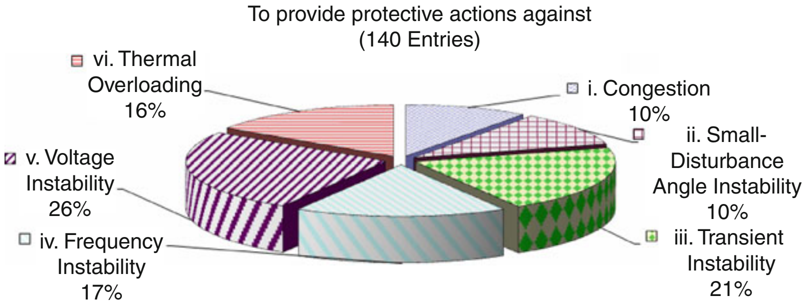


Fig. 4.4 SIPS purpose

classification. The numbers of SIPS performing similar types of functions have been grouped to indicate the total number of SIPS types. For each type of SIPS scheme, the number of schemes serving a similar purpose has been indicated, with the following classification:

1. Essential: Prevent cascading outages
2. Increased Security: Minimize area affected by undesirable conditions
3. Increased Power Flow Capability: To extend transmission system rating without adding new transmission facilities or to delay enhancement of transmission networks
4. Important: Avoid difficult operating conditions
5. Normal: A better functioning of the network

Note that almost all classifications are evenly distributed (with exception of "Important" which is at 8%). The approximate even distribution of classifications of SIPS highlights the important role of SIPS in grid reliability and how SIPS are integrated part of the grid development worldwide.

It is clear from Fig. 4.3 that the application of SIPS has become a component of a comprehensive total grid operation and protection philosophy. The fact that 22% of the entries are applications to address "normal" system conditions demonstrates that SIPS are no longer applied solely for system security purposes. In fact, close examination of Fig. 4.3 reveals SIPS applications can be viewed as two major categories:

- *Operational system improvement* (49% with three components: 19% Increased Power Flow, 8% Important, plus 22% Normal)
- *System security* (51% with two components, 22% Essential plus 29% for Increased Security) which at one time was the primary intent of SIPS

Figure 4.4 shows the intent of the various types of SIPS. The fact that voltage instability is the most often addressed phenomenon confirms that systems are now more complex than ever. The voltage stability phenomenon was firstly discovered at the beginning of 1980s as systems were getting more complex. The information in Fig. 4.4 correlates with the classifications in Fig. 4.3, demonstrating that worldwide SIPS are integrated components of various aspects of grid operation.

System Restoration

Another critical step in minimizing the impact of widespread blackouts is the need for effective and fast power system restoration. Returning equipment to service followed by quick restoration of power to the users is of paramount importance and can significantly minimize consequences of further outages.

Today's technology can be used to our advantage for intelligent restoration. Some of the key elements for responsive restoration are the following:

- Well-defined procedures that require overall coordination within the restoring area, as well as with the neighboring electric networks.
- Reliable and efficient restoration software tools significantly aid operators and area coordinators to execute operating procedures and to make proper decisions. This tool is a part of EMS/SCADA system that provides voltage, frequency, excitation, outage status, and other data.
- Regular training sessions to assure effectiveness of the process. These sessions should include practice drill scenarios. The drill scenarios should incorporate any regional reliability or governmental policy requirements. For example, there may be a time delay requirement for load restoration after bulk power system has returned to service, to allow the system to stabilize. There may also be critical loads, which must be given higher priority in restoration.
- Substations need to be manned to open breakers or switches to clear re-energization pathways and establish ability to control load restoration.

Today's technology allows us to propel in designing schemes to aid in quick restoration. Even if advanced tools and procedures are in place to speed up restoration, there are limits on how fast the system can be restored depending on the type and distribution of generation. After the August 14, 2003 blackout in North America, it took considerable time to restore generation. Some of the units did not have capabilities to be put in service immediately (black-start capabilities), and some units required longer time to be put on-line with full power (e.g., nuclear units due to security and steam turbines due to allowable ramp-up rates). Also of equal consideration is the type of load served, the system configuration, and the effects of connecting the load back to the network (Cold Load Pickup or Hot Load Pickup affects end user restoration time). While most of the cities have been restored in 5–9 h during the Italian blackout in September 2003, it took over a day to restore power back to Detroit and New York. Göran Andersson points out that in the recent Swedish-Danish blackout, the 400 kV grid was restored within 2 h, most customers were connected within 4 h, and the last customer reconnected within 6 h.

Mayer Sasson explains the slower pace for load restoration experienced in New York. The low-voltage network loads in New York City and Manhattan area are a highly meshed network system that affords a very high degree of reliability against localized outages. However, under blackout conditions, when a network is to be restored, the network is isolated into 100–200 MW portions that need to be re-energized at a time, requiring a time-consuming and careful process such that the inrush does not provide a set back to the restoration effort.

As discussed before, by designing the power system to transfer power across large distances and not providing enough reactive power close to the load or building the accompanying transmission lines may have detrimental effects on power system operation. Similarly, designing the power system not considering the effects on restoration efforts may have detrimental effects on the speed of restoration. In conclusion, restoration time and system security could be significantly improved by planning of the generation mix and location considering not only market factors but incorporating value of reliable operation and faster restoration in the financial model. This approach would result in optimal, long-term investment strategies.

Future Directions

As the power grids worldwide have become more complex and are operated closer to the operating limits, applications of Wide Area Monitoring, Protection, and Control (WAMPAC) systems have become necessary to better manage the grid reliability and performance security [15]. Control areas within the interconnected grids or among countries are recognizing that bulk power systems should be treated as one system and power system professionals are challenged to upgrade the system with technologies that makes the task of grid control manageable. New technologies such as synchronized measurements have advanced to support commercial WAMPAC deployment so that implementation of various applications is both possible and warranted, representing prudent investment.

Although large-scale demonstrations of using this technology are reported around the world, full-fledged productized systems have just started to be deployed. In the USA, those initiatives have been driven by transmission "smart grid" investments supported by DOE stimulus grants and NERC. WAMPAC systems using synchronized measurements have some unique deployment challenges as they require engagement of multiple users with diverse requirements and varying needs. Such large-scale systems not only offer a lot of promising reliability and financial benefits but also push the boundaries of conventional grid operations.

Synchronized measurement applications, using GPS synchronized Phasor Measurement Units (PMUs), offer large reliability and financial benefits for customers/society and the electrical grid when implemented across the interconnected grid. As measurements are reported 20–60 times per second, PMUs are well suited to track grid dynamics in real time. Compared to current EMS monitoring tools that use information from state estimation and SCADA over several second intervals, time-synchronized PMUs introduce the possibility of directly measuring the system state instead of estimating it based on system models and telemetry data. If implemented

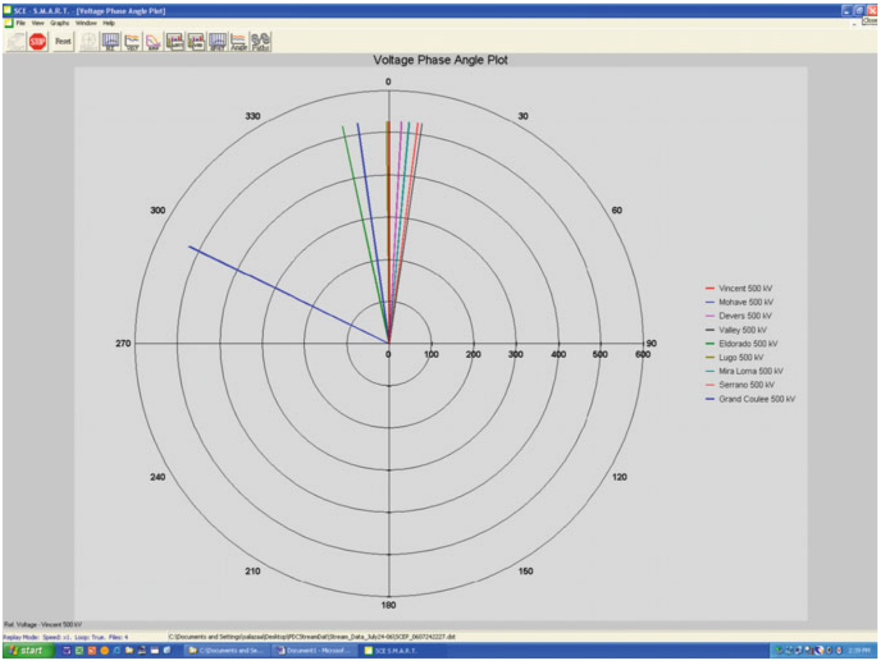


Fig. 4.5 Key system voltage angles – WECC disturbance on July 24, 2006

properly, the technology also allows for providing data integrity validation without added cost. This technology is instrumental for:

- Improving WAMPAC in real time including applications such as early warning systems, SIPS, detection and analysis of system stability, etc., and enabling faster system restoration
- Faster and more accurate analysis of vast number of data during transient events
- Validation and development of power system models

All of the above helps with avoidance and analysis of outages that may have extreme manifestation in blackouts. Due to its accuracy and wide-area coverage, synchronized measurement technology is a paradigm shift enabling unique tracking of power system dynamics. Synchronized measurement applications enable true early warning systems to detect conditions that lead to catastrophic events, help with restoration, and improve the quality of data for event analysis.

The display shown in Fig. 4.5 is a dynamic angle display during the disturbance in the western part of the USA in 2006. Those types of displays are used both for post-disturbance analysis and as an operational tool to help during the disturbance.

The conceptual WAMPAC system has interesting parallels with the human nervous system. Figure 4.6 shows the simplest concept of a WAMPAC system that spans a complete utility transmission system, or even an entire unified operating region. This conceptual description focuses on likely future implementations, without

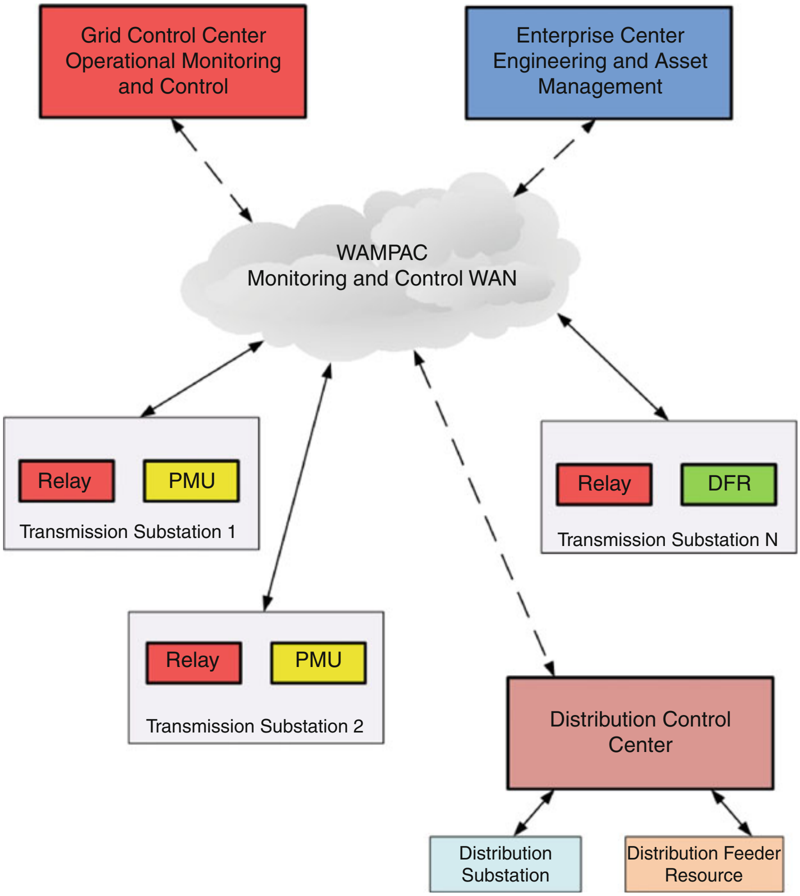


Fig. 4.6 Basic conceptual WAMPAC system

concern of integrating today's persistent but obsolescent components like independent SCADA RTUs. WAMPAC is in fact ultimately capable of absorbing all of the functions of today's SCADA and EMS, including not only measurement and control but also state estimation and real-time contingency analysis.

In summary, Wide Area Monitoring, Protection, and Control (WAMPAC) is a must for transmission smart grid as it is necessary to increase probability to prevent blackouts by improving following applications [15]:

- Data analysis and visualization – Significant benefits are achieved with the ability to analyze events much faster in a synchronized fashion on-line or post-mortem.
- System reliability improvement by preventing cascading outages due to voltage, angular, and frequency instability, thermal overloads, and low frequency oscillations – These applications result in huge societal benefits.

- System operations and planning, improved modeling – Synchronized measurement enables paradigm shift with high reporting rates not available with any other technology and in developing accurate power system models.
- Market operations: Congestion Management and Locational Marginal Pricing – These applications enable large financial benefits by better grid utilization.

With today's technology, it is possible to tie all the monitoring, control, and protection devices together through an information network. The key to a successful solution is fast detection, fast and powerful control devices, communication system, and smart algorithms.

Conclusions

Power system is very complex and human-made. Our industry needs to keep planning, operating, and maintaining it as efficient and as reliable as possible, including preventing blackouts. There is a general understanding of blackouts caused by natural disasters (earthquake, hurricanes, etc.). However, system-wide outages created by humans and/or not arrested due to suboptimal design should be easier to prevent. Analysis of large disturbances reveals some common threads among them, leading to the following conclusions:

- Need to understand the symptoms and root causes of the major disturbances and learn from the past blackouts.
- The power grid should not be operated under system conditions that have not been studied.
- Implement specific solutions to reduce the likelihood and propagation of outages.
- Restoration time could be reduced.

In summary, although it is not possible to avoid multiple contingency initiated blackouts, the probability, size, and impact of wide-area blackouts could be reduced and the propagation stopped.

Although electrical industry (utilities, ISOs, generation owners, regulators, universities, etc.) takes major initiatives after blackouts (such as investments in "smart grid" technologies), grids around the world always face host of new and old challenges. Applying a patchwork of individual measures to manage the grid is not sufficient. It is necessary to take a balanced approach to fixing the system as a whole by implementing a well-defined and coordinated overall strategy including various planning, operations, maintenance, and regulatory measures, weighing the costs, performance, and risks associated with each measure. It is important to always envision how power system should operate 10–30 years in the future; then design and overhaul it with this forward-looking approach.

Within the context of this approach, specific solutions to reduce the likelihood of outages can be addressed – because once the overall causes of wide-area disturbances are minimized, the smaller contributing factors are easier to handle, further diminishing the incidence of failures. The advent of advancements in information technology (IT), innovations in power system monitoring, and deployment of advance warning systems enables tools to arrest the grid from wide-area blackouts and meet the expectations for reliable power delivery. For example, while investing in strengthening the electrical grid infrastructure, such as rebuilding T&D grid and installing new generation and controls (e.g., reactive power devices, FACTS, HVDC), could not be replaced, "smart grid" WAMPAC deployment is necessary and cost-effective way to improve grid reliability. Under normal conditions, and with sufficient automatic supports, operators are able to adequately control power system operation. However, the speed and complexity of disturbance phenomena makes control of the grid more suited to automated WAMPAC systems to respond to fast developing and complex disturbances.

Acknowledgment The author expresses appreciation to the following Distinguished Industry Experts for their contributions and guidance: Göran Andersson, Miroslav Begovic, Daniel Karlsson, Bogdan Kasztenny, Mayer Sasson, Carlson Taylor, Chifong Thomas, Vijay Vittal, Jim Thorp, and Eric Udren. Special appreciation and recognition is extended to the Distinguished Expert Vahid Madani, whose ideas and work have been instrumental for the completeness of this chapter.

Bibliography

Primary Literature

1. Novosel D, Begovic M, Madani V (2004) Shedding light on blackouts. IEEE Power and Energy Magazine, Jan/Feb 2004 (lead article)
2. Madani V, Novosel D (2005) Getting a grip on the grid. IEEE Spectrum, pp 42–47 December 2005. Also, Taming the Power Grid in www.spectrum.ieee.org
3. Novosel D, Madani V (2006) Blackout Prevention. In: Yearbook of Science and Technology, McGraw Hill, pp 34–38
4. Madani V, Novosel D, Apostolov A, Corsi S (2004) Innovative solutions for preventing wide area disturbance propagation. In: IREP symposium, Cortina d'Ampezzo, Italy, Aug 2004
5. WECC (1996) Western system coordinating council disturbance report for the power system outage that occurred on the western interconnection. www.NERC.com
6. U.S.-Canada Power System Outage Task Force (2004) Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. www.FERC.gov, April 2004
7. UCTE (2007) System disturbance on 4 Nov 2006. http://www.ucte.com
8. Fairley P (2004) Unruly power grid. IEEE Spectrum 41(8):22–27
9. Horowitz SH, Phadke AG (2003) Boosting immunity to blackouts. IEEE Power and Energy Magazine, Sept/Oct 2003
10. CIGRE WG C2.02.24 (2007) Defense plan against extreme contingencies. ELECTRA, pp 46–61, Apr 2007
11. Horowitz S, Novosel D, Madani V, Adamiak M (2008) System-wide protection. IEEE Power and Energy Magazine, Sept/Oct 2008

12. Madani V, Novosel D, Begovic M, Adamiak M (2008) Application considerations in system integrity protection schemes (SIPS). GE Protection and Control Magazine, pp 25–30, May 2008
13. Madani V, Novosel D, Horowitz S, Adamiak M, Amantegui J, Karlsson D, Imai S, Apostolov A (2010) IEEE PSRC report on global industry experiences with system integrity protection schemes (SIPS). IEEE Trans PWRD 25(4):2143–2155
14. Novosel D, Bartok G, Henneberg G, Mysore P, Tziouvaras D, Ward S (2010) IEEE PSRC report on performance of relaying during wide-area stressed conditions. IEEE Trans PWRD 25(1):3–16
15. Novosel D, Madani V, Bhargava B, Vu K, Cole J (2008) Dawn of the grid synchronization. IEEE Power and Energy Magazine, vol 6, Jan/Feb 2008, pp 49–60

Books and Reviews

Kundur P (1994) Power system stability and control. McGraw-Hill, New York

Massoud Amin S, Wollenberg BF (2005) Toward a smart grid. IEEE Power and Energy Magazine, Sept–Oct 2005

Phadke AG, Thorp JS (2008) Synchronized phasor measurements and their applications. Springer, New York

Taylor CW (1999) Improving grid behavior. IEEE Spectrum 36:40–45

Chapter 5
Wide Area Monitoring, Protection and Control

James S. Thorp and Arun G. Phadke

Glossary

Adaptive protection	A protection philosophy which permits and seeks to make adjustments automatically in various protection functions in order to make them more attuned to prevailing system conditions.
Fault	A short circuit in the power system.
GPS	Global Positioning System.
Hidden failure	A defect or error in relay that does not manifest itself immediately but which can cause a miss-operation when the system is stressed.
NERC	North American Electric Reliability Corporation.
Phasor	A complex number describing a sinusoidal signal.
PMU	Phasor Measurement Unit.
RTU	Remote Terminal Unit.
SCADA	Supervisory Control and Data Acquisition.
Synchrophasor	A phasor measurement with a precise time tag.
WAMS	Wide Area Measurement System.

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3

J.S. Thorp (✉) • A.G. Phadke
Bradley Department of Electrical and Computer Engineering,
Virginia Polytechnic Institute and State University, 302 Whittemore (0111),
Blacksburg, VA 24061, USA
e-mail: jsthorp@vt.edu; aphadke@vt.edu

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*, DOI 10.1007/978-1-4614-5830-2_5, © Springer Science+Business Media New York 2013

Definition of the Subject

The Electric Power Infrastructure

A power system consists of generators which convert energy from some primary form – such as coal, wind, gas, sunlight, or water flow – into electric power. Most generators in modern power systems produce alternating currents and voltages (AC) which are then transmitted over appropriate distances to supply loads. It is economical to transmit power at higher voltages in order to limit losses in the transmission lines. Voltages of desired values are obtained with the help of transformers which let through most of the power (small amount of losses are incurred in the transformers), only changing voltages and currents from one side of the transformer to the other. The "power" handled by the transformers is the product of currents and voltages, so that higher voltages have accompanying smaller currents. In general, the longer the distance for transmission, the greater is the economical voltage at which to transmit the power. Most power transmission is through overground transmission lines, while in special circumstances (such as crossing a large body of water or in congested urban areas) underground cables are used. There is a range of voltages in use for transmission: 800 (kilovolts – thousands of volts), 500, 400 kV, etc. The household voltages in most countries are 120 V or 240 V which are obtained through stages of transformations as power is passed through transmission, sub-transmission, and distribution systems. For technical reasons, sometimes it is advantageous to convert AC power to DC (direct current) power by high-power electronic converters, transmit it as DC power, and convert it back to AC at the receiving end. The power-handling capacity of total system generation is expected to be some 10–20% greater than the expected load in order to provide a margin of security. Similarly, the transmission system is planned with sufficient number of alternative paths connecting loads to generators so that should some lines get disconnected due to faults, the loads continue to be served. In North America and many countries, the frequency of the AC system is nominally set at 60 Hz, while in some other countries, it is 50 Hz. The actual frequency of the system stays close to the nominal values, and in well-regulated power systems, the variations from nominal frequency are less than 0.1 Hz. The North American power system has approximately 900 gigawatts (900,000,000,000 W) of power generation capacity – consisting of about 70% thermal power generators, 14% hydroelectric generators, 13% nuclear, and small amounts of wind, solar, and other renewable power sources. The continent is crisscrossed by about 200,000 circuit miles of high-voltage transmission lines, further supplemented by lower-voltage distribution circuits serving customers at lower voltages at the load centers. The generation capacity in North America is sufficient to meet load demands with adequate margins overall, although in spot locations, the available margins or transmission capacity may not be sufficient.

Operating the Power Grid Reliably

In order to provide electric power reliably to consumers, it becomes necessary to manage the generation, transmission, and consumption of electric power in an efficient manner. Since the load demand is controlled by the consumers and may change randomly depending upon consumers' wishes, and since the generation must match this demand (and losses) instant by instant, an elaborate system of controls is put in place at generators and at Energy Management Centers on the power grid. Such controls must take into account the possibility of faults in the system due to natural disasters (floods, hurricanes, and fires), equipment failure, or man-made disasters. These events are contingency events, and the power grid must continue to meet the demands of consumers with minimum interruptions when faced with such contingencies. In addition, the power system must maintain its operating frequency within a narrow band around the nominal value (60 Hz in North America), and the operating voltage at the consumers' locations within a narrow band around its nominal value. To be prepared to deal with a reasonable set of contingencies adequately, it is necessary that the system operators are made aware of the condition of the power infrastructure accurately at all times. This is achieved through a system of measurements made on the power grid at frequent intervals, from which the network flows and voltages are estimated. The technical term for this process is "state estimation" of the power system. The ability of the power system to meet its loads in the presence of contingencies is much enhanced if the state of the system is known precisely and with sufficient frequency so that as the transmission system, loads, and generation change during the day, the changes are tracked accurately by the measurement process. A measurement technique made possible by the advent of digital computer-based measurements and the Global Positioning System (GPS) is the highly precise and effective "synchrophasors" technology.

Sine Waves, Phasors, and Synchrophasors

Alternating currents and voltages vary as sinusoids with a period determined by the frequency of the system. Thus, in North America where the frequency is 60 Hz, a nominal voltage or current will vary with time as shown in Fig. 5.1. Note that the sinusoid is shown to be a pure sine wave, whereas in practice, the waveform could have some noise in it. A *phasor* is a mathematical way of representing this sinusoid. It is a complex number with its magnitude equal to the RMS (root mean square) value of the sinusoid, and its phase angle is the angle measured with respect to the start of the time axis and the peak of the sinusoid. One period is equivalent to 2π radians or 360°. Angles measured to the left of $t = 0$ are positive angles, and angles measured to the right are negative angles. Thus, the phasor representing the sinusoid in Fig. 5.1 is given by:

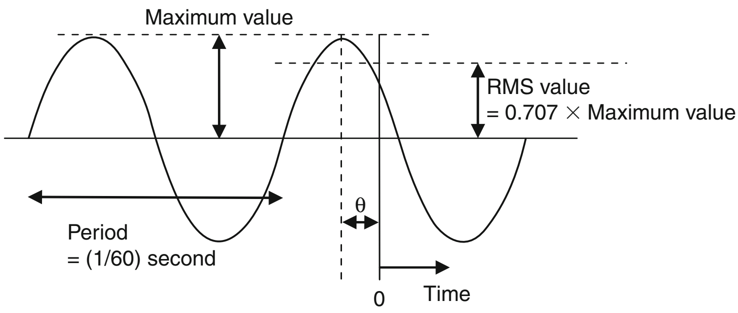


Fig. 5.1 A sinusoidal voltage or current and its phasor representation

$$\text{Phasor} = \mathrm{X}\varepsilon^{\mathrm{j}\theta} = \mathrm{X}\cos\ \theta + \mathrm{j}\ \mathrm{X}\sin\theta$$

where X is the RMS value of the sinusoid. Phasors are generally calculated from samples taken from a sinusoid over a time span known as data window, which is usually of the order of one period of the sinusoid.

The GPS satellite system transmits (among other data) a 1-pulse-per-second (1 pps) which can be received by GPS receivers. A characteristic of the GPS system is that a 1 pps received by any receiver placed anywhere on earth is within 1 μs of the pulse received by another GPS receiver. Consider a power system shown in Fig. 5.2 in which different power facilities (substations) are separated by large distances. The sinusoids of voltages and currents in the two substations would in general be different from each other in magnitudes and phase angles of the sinusoids. A sinusoid at the substation shown in red in Fig. 5.2 is measured from the instant shown as t = 0, which is identified with the 1 pps received from the satellite, while the measurement at the substation shown in green has the t = 0 time marker at the same instant, and measures the phasor at that location. The two synchrophasors can now be placed on the same phasor diagram and show correctly the relative magnitudes and phase angles of the two signals as they exist at that instant. Synchrophasors can be measured at all network buses and assembled at the system control center to form a coherent picture of the state of the power system. Such a picture can be refreshed as frequently as once per cycle of the power system frequency and is thus able to track the behavior of the power system as it goes through normal or abnormal changes brought about by daily load variations or major disturbance. This ability to monitor the power system continuously with precise simultaneous measurements is made possible by the technology of the synchrophasors.

Importance of Positive Sequence Measurements

The entire AC power system is made up of three-phase sources and loads. (Three-phase system makes the most economical use of the capability of large generators and motors.) The three phases are considered to be balanced in most normal operating conditions. When faults or unusual disturbances occur, the system may

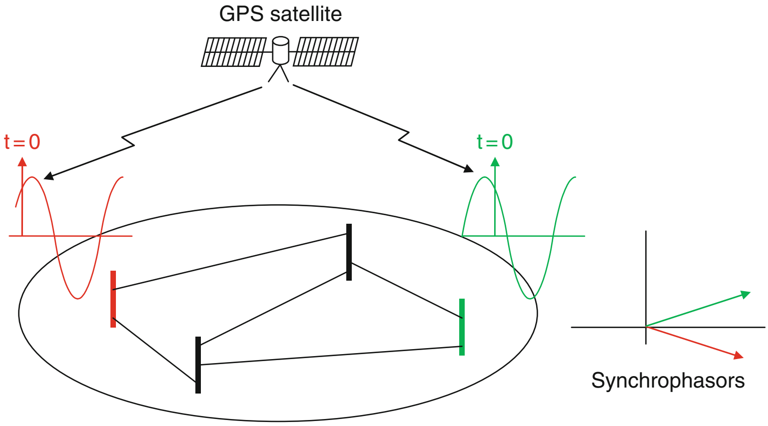


Fig. 5.2 Voltages and currents in substation at different locations

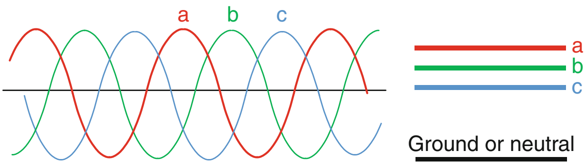


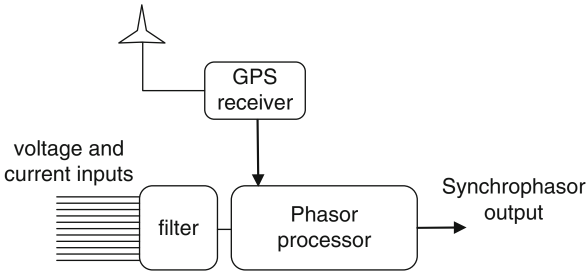
Fig. 5.3 Balanced voltages and currents in a three-phase power system

become severely unbalanced, but such unbalances last only for a short time, and the system soon returns to a balanced state. It is well to provide a more precise definition of balanced operation.

When the voltages and currents in a three-phase AC system are of equal magnitude and differ in phase from each other by equal amounts (360°/3 = 120°), the system is said to be balanced. This is illustrated in Fig. 5.3, where the three signals (voltages or currents) of the three phases are illustrated by red, green, and blue colors. The three phases are usually labeled.

"a," "b," and "c" in most power systems, although in some countries, they are referred to by three different colors (red, yellow, and blue). If the power system is balanced, it turns out that it is not necessary to consider it to be a three-phase system in most computational tasks; all analyses can be performed in a single-phase mode, and from the single-phase results, the conditions in the three phases can be inferred. This leads to much simpler computational procedures for all power system problems. Technically, this single-phase representation is known as the *"positive sequence"* representation. In general, a three-phase parameter (voltage, current, or impedance) can be represented by three "sequence" components: positive, negative, and zero. Under balanced conditions, only the positive sequence component exists, and the negative and zero sequences are zero. When severe unbalances occur (e.g., when there is a line to ground fault), negative and zero sequence components become significant. Even in normal operation, there may be a small amount of

Fig. 5.4 A simplified block diagram of a generic PMU



unbalance present in the power system; thus, small amounts of negative and zero sequence components may exist on the power system during normal operating conditions. However, for most analyses, it is assumed that the unbalance can be neglected, and the power system may be assumed to be balanced; hence, only a single-phase representation using positive sequence voltages, currents, and impedances is appropriate.

Since most power system problems are handled with positive sequence quantities, it is most advantageous to measure synchrophasors of positive sequence voltages and currents. This is accomplished by measuring synchrophasors of individual phase voltages and currents (X_a, X_b, and X_c) and calculating positive sequence synchrophasors (X_1) from them:

$$X_1 = 1/3\left[X_a + \left(-1/2 + j\,\sqrt{3/2}\right)X_b + \left(-1/2 - j\,\sqrt{3/2}\right)X_c\right]$$

Phasor Measurement Unit (PMU)

Synchrophasors are measured by Phasor Measurement Units (PMU) installed in power system substations. A simplified schematic diagram of the PMU is shown in Fig. 5.4.

Currents and voltages from the power system are transformed to measurement levels by instrument transformers, which are then supplied to the filter stage of the PMU which removes destructive induced voltages and currents as well as higher frequencies in order to avoid aliasing errors in the sampled data. The GPS receiver provides the 1 pps from the GPS satellites and is divided into desired sampling rates by a phase-locked clock. Typical sampling rates may vary between 12 samples per cycle of the power frequency to higher sampling rates measured in kilohertz. The phasor processor converts samples of each phase into a synchrophasor and finally into a positive sequence synchrophasor measurement which is assigned a time stamp before the measurements are transmitted over a suitable communication network to provide a stream of synchrophasor measurements. Typical reporting rates for the synchrophasors are of the order of once every cycle to once every few cycles depending upon the user's requirements.

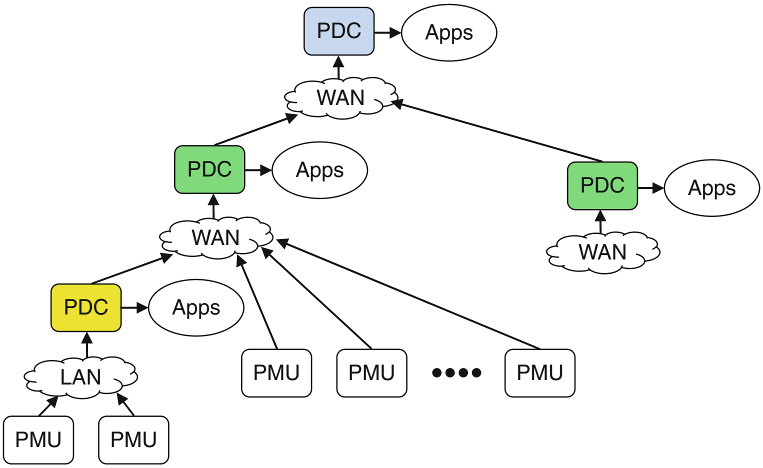


Fig. 5.5 Wide area measurement system architecture

WAMS Architecture Overview

WAMS (Wide Area Measurement System) consists of Phasor Measurement Units (PMU) installed in power system substations and connected to one or more layers of Phasor Data Concentrators (PDC) so that system-wide phasor data can be made available at various regional or central locations for engineering applications (see Fig. 5.5). The PMUs are placed in substations, where they collect voltage and current data. If multiple PMUs exist within one substation, their outputs are streamed to a PDC within the substation – shown in yellow color – over a local area network (LAN). Where there is one PMU per substation, the data from those PMUs and the substation PDC is connected to a regional PDC – shown in green color – over a wide area network (WAN). Regional PDCs in turn can be connected to a central PDC – shown in blue color – over another WAN. Each PDC basically collates data from the lower-level devices and by matching their time stamps creates a data stream as though it was a PMU with many inputs. The PDC may also remove faulty data, deselect some data, or alter the phasor reporting rate as required by specific applications.

The LAN and WAN are likely to be private wired or fiber-optic communication networks on which high communication rates can be achieved. It is not expected that public WAN would be used for this purpose, as the questions of security and communication delays may rule this option out. In many cases where fiber-optic options are not available, digital microwave, leased phone lines, or any other available communication channels may be utilized by the WAMS system. Of course, the throughput rate as well as data latency of communication media dictates which of the WAMS applications can be successfully implemented in such systems.

Suitable application tasks may be implemented at each PDC. Clearly, the data available at each PDC covers differing regions of the power system. Applications of

WAMS for power system monitoring, protection, and control will be described in the following sections, where the amount of data needed by a specific application and the region of the power system which must be visible to the application will be discussed. As a general rule, the applications at lower levels of PDC require lesser amounts of data and respond more quickly than those at higher-level PDCs. In general, it has been found that the fast-responding applications can tolerate measurement latencies in the order of 50–100 ms.

Power System Monitoring

Reconstruction of Events

The job of reconstructing the events involved in a major disturbance is a daunting one. Months and immense effort is involved. It is typically difficult even to determine the sequence of events. Phasor measurements with precise time tags were not numerous in 2003, but the few that did exist stood out among the unsynchronized data. From the simple function of fault recorders to complicated reconstructions involving thousands of buses, time-synchronized measurements are vital.

State Estimation

One of the conclusions of the report on the 1965 Northeast blackout was that, at that point, power system operators had insufficient information about the system they were controlling. State estimation and the modern energy management system were created to deal with these problems. Early state estimation "polled" SCADA systems connected to Remote Terminal Units in substation by moving systematically from substation to substation covering the entire system is the total scan. The measurements were power flows on lines, power inputs (injections) into buses, and occasional voltage magnitudes. It was necessary to assume that the system was *static* during the scan, i.e., the system did not change during the scan. Another view of the resulting estimate of the state is that it is the state of a hypothetical system which could support the complete set of measurements. Depending on how long the scan takes and the changes in the system that took place during the scan, the hypothetical system may not exist or may be quite different from the real system. The state of the power system was taken as the positive sequence voltages at the buses which could not be measured directly. The measurements and the estimated state were all complex numbers, magnitudes and angles, or real and imaginary parts. The calculation had to solve large numbers of nonlinear equations and was iterative. That combined with the data scan made the process slow with new estimates available every few minutes [1]. The result was a picture of the state of the system presented to operators and to the software that did the energy management (contingency analysis, for example). Faster computers and improved communication have reduced minutes to seconds over the decades.

The complex voltage at bus k with angle θ_k and magnitude V_k is given by

$$E_k = V_k e^{j\theta_k}$$

The measurements are complex flows and injections. The real power flow from bus r to bus r with a series impedance z_{rs} between r and s and a shunt admittance at bus r of y_r is

$$\begin{aligned} P_{rs} = V_r^2[|Y_{rs}|\cos(\beta_{rs}) + |y_r|\cos(\alpha_r)] \\ -V_r V_s \cos(\theta_r - \theta_s - \beta_{rs}) \end{aligned}$$

where α_r and β_{rs} are the angles of the admittance of the series and shunt branch respectively:

$$\frac{1}{z_{rs}} = |Y_{rs}|e^{-j\beta_{rs}} \quad y_r = |y_r|e^{j\alpha_r}$$

In general, the measurements depend on the states which are complex voltages $\mathbf{V}$ at angle $\boldsymbol{\theta}$.

$$\mathbf{z} = \mathbf{g}(\mathbf{V}, \boldsymbol{\theta}) + \boldsymbol{\epsilon}$$

Usually, the measurement errors are assumed to have zero mean and are independent, with a diagonal covariance matrix $\mathbf{W}$:

$$\mathrm{E}\{\epsilon\} = 0, \quad \mathrm{E}\{\boldsymbol{\epsilon}\boldsymbol{\epsilon}^{\mathbf{T}}\} = \mathbf{W}, \quad \mathrm{w_{ij}} = 0, \quad \mathrm{w_{ii}} = \sigma_{\mathrm{i}}^2$$

The estimate is formed by minimizing the weighted differences between the actual measurements and the computed measurement as a function of **V** and **θ.** The weights are the inverse of the covariances giving more weight to better measurements and less to low-quality measurements:

$$\begin{aligned} J(\mathbf{V}, \boldsymbol{\theta}) &= [\mathbf{z} - \mathbf{g}(\mathbf{V}, \boldsymbol{\theta})]^{\mathbf{T}} \mathbf{W}^{-1} [\mathbf{z} - \mathbf{g}(\mathbf{V}, \boldsymbol{\theta})] \\ &= \sum_{i=1}^{m} \frac{(z_i - g_i(V, \theta))^2}{\sigma_i^2} \end{aligned}$$

Writing a Taylor expansion about the last iterate $\mathbf{V^k}$, $\boldsymbol{\theta}^{\mathbf{k}}$:

$$\mathbf{g}(\mathbf{V}, \boldsymbol{\theta}) = \mathbf{g}(\mathbf{V^k}, \boldsymbol{\theta}^{\mathbf{k}}) + \mathbf{G} \begin{bmatrix} \mathbf{V} - \mathbf{V^k} \\ \boldsymbol{\theta} - \boldsymbol{\theta}^{\mathbf{k}} \end{bmatrix}$$

where $\mathbf{G}$ is a matrix of first partial derivatives of the elements of $\mathbf{g}$ with respect to the components of $\mathbf{x}$ evaluated at x^k. If

$$\begin{bmatrix} \Delta\mathbf{V} \\ \Delta\boldsymbol{\theta} \end{bmatrix} = \begin{bmatrix} \mathbf{V} - \mathbf{V}^{\mathbf{k}} \\ \boldsymbol{\theta} - \boldsymbol{\theta}^{\mathbf{k}} \end{bmatrix}, \quad \Delta\mathbf{z} = \mathbf{z} - \mathbf{g}(\mathbf{V}^{\mathbf{k}}, \boldsymbol{\theta}^{\mathbf{k}})$$

then one step in the iteration is given by

$$\mathbf{G}^{\mathbf{T}}\mathbf{W}^{-\mathbf{1}}\mathbf{G} \begin{bmatrix} \Delta\mathbf{V} \\ \Delta\boldsymbol{\theta} \end{bmatrix} = \mathbf{G}^{\mathbf{T}}\mathbf{W}^{-\mathbf{1}}\Delta\mathbf{z}$$
$$\mathbf{H} \begin{bmatrix} \Delta\mathbf{V} \\ \Delta\boldsymbol{\theta} \end{bmatrix} = \mathbf{G}^{\mathbf{T}}\mathbf{W}^{-\mathbf{1}}\Delta\mathbf{z}$$

The gain matrix $\mathbf{H}$ is large and sparse, and the equation is usually solved with Gaussian elimination. The matrix $\mathbf{G}$ is sparse much like the load flow Jacobian. By organizing the measurements into active and reactive power, the equivalent of the fast decoupled load flow can be used to simplify the expression further. With real or active power measurements (sub A) first followed by reactive power (sub R):

$$\mathbf{z} = \begin{bmatrix} \mathbf{z_A} \\ \mathbf{z_R} \end{bmatrix}, \quad \mathbf{z_A} = \begin{bmatrix} \mathbf{P_{km}} \\ \mathbf{P_k} \end{bmatrix}, \quad \mathbf{z_R} = \begin{bmatrix} \mathbf{Q_{km}} \\ \mathbf{Q_k} \\ \mathbf{V_k} \end{bmatrix}$$

and states as angles followed by voltage magnitudes to form

$$\begin{bmatrix} \mathbf{H_{AA}} & \mathbf{0} \\ \mathbf{0} & \mathbf{H_{RR}} \end{bmatrix} \begin{bmatrix} \Delta\boldsymbol{\theta} \\ \Delta\mathbf{v} \end{bmatrix} = \mathbf{G}^{\mathbf{T}}\mathbf{W}^{-\mathbf{1}} \begin{bmatrix} \Delta\mathbf{z_A} \\ \Delta\mathbf{z_R} \end{bmatrix}$$

Using the assumptions from the fast decoupled load flow (small angle difference, voltage magnitudes near 1, and large X/R for the lines), the off diagonal blocks of $\mathbf{H}$ are zero. An approximate $\mathbf{H}$ can even be computed with angles set equal to zero and voltage magnitudes set equal to one at the cost of more iterations.

The addition of even a few direct measurements of angle to the previous formulation has a number of advantages and creates symmetry in the problem statement. When angle measurements are included, z_A and z_R both have three entries [2, 3]:

$$\mathbf{z} = \begin{bmatrix} \mathbf{z_A} \\ \mathbf{z_R} \end{bmatrix}, \quad \mathbf{z_A} = \begin{bmatrix} \mathbf{P_{km}} \\ \mathbf{P_k} \\ \boldsymbol{\theta}_\mathbf{k} \end{bmatrix}, \quad \mathbf{z_R} = \begin{bmatrix} \mathbf{Q_{km}} \\ \mathbf{Q_k} \\ \mathbf{V_k} \end{bmatrix}$$

The matrix $\mathbf{G}$ is modified in an obvious manner, but otherwise, the previous development applies. In order to use the PMU measurements in the conventional

SCADA-based system, it is also necessary to put those measurements on the same reference as the convention estimate which has a reference bus. This generally requires the addition of a PMU at the reference bus.

PMUs can also measure the currents in lines connected to the bus. The addition of line currents measurements can be used to compute the bus voltages on adjacent buses if the line model is known. The PMU measurements of both voltage and current have time tags and are different in nature from the SCADA measurements but can improve the conventional estimates even if the time tag is not used and the PMU data is simply treated as additional SCADA data.

PMU-Only Estimators

A modest number of PMUs will permit a PMU-only measurement system for selected parts of the system. For example, a PMU-only estimator for the 500-kV portion of a utility is quite possible. Phasor measurements of the bus voltages and line currents at some 500-kV buses can form the basis of a linear estimate for the 500-kV system that can be updated as often as once a cycle. There have been studies of the number of PMUs required, their location, the phasing in of such systems, and their reliability [4–6]. While the results of these papers are interesting, the actual sequence of installation of PMUs and the locations of the PMUs are frequently far from optimal. Many other issues influence these decisions in the real world.

Even recognizing the practical side of the problem, the theoretical results are that fewer PMU are required than might have been imagined. If we assume that any PMU can measure the bus voltage and all of the line currents at that bus (for a large number of lines, this may not be true for some PMUs, and more than one PMU must be installed in a substation), then the problem of the minimum number of substations required to measure the state of the system can be solved. The most direct solution technique uses the node-node incidence matrix for the system. The matrix A has only 0s and 1s with $A_{ii} = 1$ and $A_{ij} = 1$ if there is a line from bus i to bus j. Using a vector x which has a one in position j if substation j is equipped with PMUs, then for any x the product y = Ax can be formed. Then, y_k is the number of times the voltage at bus k is seen by the various PMUs. If x = [1 0 0 1 0 0 1 0 0 1 0 0 1 0]' indicating PMUs at bus 1, 4, 7, 10, and 13 in the IEEE 14 bus system with A matrix below, then y = [1 2 1 2 2 1 2 1 3 1 1 1 1 1]', indicating that monitoring these five buses can completely observe the system. Nine of the buses are seen by only one PMU, however.

Assuming that only some PMU measurements of bus voltages and line currents are used in the estimate, consider the pi equivalent for a transmission line in Fig. 5.6. The state of the system is the set of complex bus voltages. The measured currents are linear function of the state, assuming the line parameters are known.

The measurements at both ends of the line are

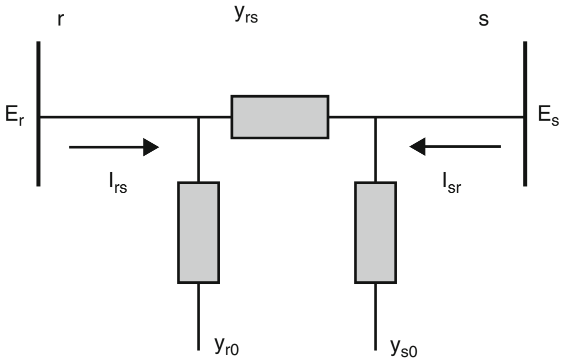


Fig. 5.6 Pi equivalent of a transmission line

$$\begin{bmatrix} Ep \\ Eq \\ Ipq \\ Iqp \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ 0 & 1 \\ y_{pq} + y_{p0} & -y_{pq} \\ -y_{pq} & y_{pq} + y_{q0} \end{bmatrix} \begin{bmatrix} Ep \\ Eq \end{bmatrix}$$

For a more complex network, the measurements can be written as

$$\mathbf{z} = \begin{bmatrix} \mathbf{II} \\ \mathbf{YA} + \mathbf{Y_s} \end{bmatrix} [\mathbf{E_b}] = \mathbf{BE_B}$$

where **II** is related to a unit matrix with diagonal entries equal to one where a voltages is measured and zero otherwise. The second set of measurements are the currents expressed as flows in the shunt elements through y_s and in the series branches. **A** is an incidence matrix, and y is a matrix of series impedances. The matrices **Y** and $\mathbf{Y_s}$ are complex while the entries in **II** and **A** are only zeros and 1. With **Y = G + jB** and **Ys = Gs + jBs**, both the measurements and states can be written as real and imaginary, and the real products are (real*real-imag*imag) and the imaginary product as (real*imag + imag*real) to form

$$\begin{bmatrix} \mathbf{z_r} \\ \mathbf{z_x} \end{bmatrix} = \begin{bmatrix} \begin{bmatrix} \mathbf{II} \\ \mathbf{GA} + \mathbf{G_s} \end{bmatrix} & \begin{bmatrix} \mathbf{0} \\ -\mathbf{BA} - \mathbf{B_s} \end{bmatrix} \\ \begin{bmatrix} \mathbf{0} \\ \mathbf{BA} + \mathbf{B_s} \end{bmatrix} & \begin{bmatrix} \mathbf{II} \\ \mathbf{GA} + \mathbf{G_s} \end{bmatrix} \end{bmatrix} \begin{bmatrix} \mathbf{E_r} \\ \mathbf{E_x} \end{bmatrix} + \boldsymbol{\epsilon}$$

$$\hat{\mathbf{x}} = (\mathbf{B^T W^{-1} B})^{-1} \mathbf{B^T W^{-1} z} = \mathbf{Mz}$$

The estimate is then given by the least squares solution where **W** is the covariance of the measurement errors. Note that the matrix **M** is constant, can be computed off-line, and only changes when there is a change in topology (a breaker opening). The resulting estimate is free of the static assumptions and truly dynamic.

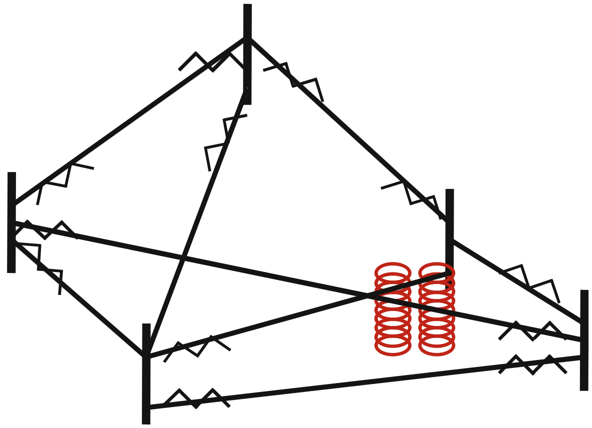


Fig. 5.7 Three-phase CTs and CVTs with a precision PT

Instrument Transformer Calibration for All-PMU Estimators

The network in Fig. 5.7 shows CTs and CVTs. A precision PT is shown in red. All CTs and CVTs are assumed to have a ratio correction factor: k_i. The true voltages and currents satisfy network equation: $E_t = ZI_t$. The actual measurements are related to true values by the ratio correction factors: $I_m = k_i I_t$. and $E_m = k_e E_t$. A set of E_m and I_m is obtained over several points during daily load variation. With sufficient number of such measurements, a WLS solution for the ratio correction factors can be formed [7]. Large numbers of simulations have shown that the k's can be determined with high accuracy (equal to that of the good PT).

With the notation of the PMU-only estimator, the calibration problem can be written as

$$\mathbf{z} = \mathbf{KBx}$$

where K is a diagonal matrix of ratio correction factors, and x is the set of complex bus voltages. Both the k's and the x's are to be estimated. It is clear that with a k for every measurement that there are too many unknowns in that if **K** and **x** are solutions the $\alpha\mathbf{K}$ and $\mathbf{x}/\alpha$ are also solutions. For this reason, one ratio correction factor is taken as 1 (the voltage measurement is taken as being correct); the k is removed from the set of unknowns. A precision PT or a new high-quality CVT can be used for this purpose.

The estimation of all the k's and all the x's from one set of measurements is not possible. It is also necessary for the states to be sufficiently different to estimate all the ratio correction factors. A possible approach is to perform the calibration place over a 12-h period with measurements at a 1-h interval used for the calibration. The calibration is a batch solution for all the states (12^* the dimension of the state) and the ratio correction factors. It is also assumed that:

1. The transformer ratio correction factors are constant over the simulation period.

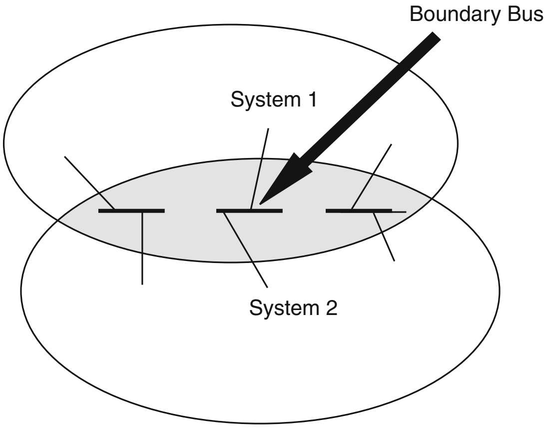


Fig. 5.8 Boundary buses between two systems

2. At least one PT is perfect, which can be used as reference to calibrate other current and voltage transformers.
3. The system model (network impedance matrix) is accurate.
4. The 12 cases are used to get 12 different operating conditions which are sufficiently redundant to estimate the ratio correction factors of transformers.

Each PTs and CTs have a ratio error of the form:

$$\text{Measurement} = \text{M}^{*}\ \text{True}$$

where M is the ratio correction factor $\text{M} = |\text{M}|\ \angle\theta$, where both M and θ are randomly distributed with zero mean. If the precision PT is not perfect but has a known accuracy η, then all the CTs and PTs will have essentially that accuracy.

Seams

Creating a single state estimator for the connection of two large independent systems each with large state estimators is a challenging task. The individual estimators may each involve tens of thousands of buses and represent many years of effort. The estimators may be of different types, come from different vendors, involve different rates, etc. The proposal that two 30,000 bus estimators be merged into one 60,000 estimator is liable to fall on deaf ears. At the simplest level, the problem can be solved by recognizing that the only problem is that the estimators have different references and place two PMUs to measure the difference in the references. A PMU at the reference bus for system 1 and a PMU at the reference bus for system 2 would be sufficient.

A slightly more elaborate solution is to include some buses near the boundary in both systems. This could be done by considering tie lines to be in both systems as shown in Fig. 5.8.

If ϕ is the angle between the references for the two systems and there are nb boundary buses, a more refined estimate of V can be obtained by averaging over the boundary buses as

$$\hat{\varphi} = \frac{1}{\mathrm{nb}} \sum_{\mathrm{i}}^{\mathrm{nb}} (\hat{\theta}_{1\mathrm{i}} - \hat{\theta}_{2\mathrm{i}})$$

where the terms in the sum are the difference between the estimated angles at bus I in the two systems. A further refinement, [8], can be made by forming a performance index including the differences between the measured and calculated real and reactive flows in the tie lines that can be minimized by choice of the angle difference ϕ.

Protection

Several areas of application of synchrophasors to protection are "adaptive" (sections "Adaptive Security/Dependability," "Adaptive Out-of-Step," and "Adaptive Loss-of-Field"). Traditionally, relays were set, and the setting could only be changed by a visit to the substation. Microprocessor relays allowed the relay engineer to change setting remotely, and the concept of adaptive protection introduced the possibility of automatic response to system conditions. "Adaptive protection is a protection philosophy which permits and seeks to make adjustments automatically in various protection functions in order to make them more attuned to prevailing system conditions" [9]. PMUs have made adaptive protection possible. There is an extensive literature on a variety of adaptive protection applications [9–15].

Adaptive Security/Dependability

Traditionally, relays have been biased toward dependability where dependability is defined as the "degree of certainty that a relay or relay system will operate correctly." There is an inevitable trade-off between dependability and security, "the degree of certainty that a relay or relay system will not operate incorrectly," that is, incorrect relay operations are either failure to trip in situations in which they should trip or trips in situations when they should not trip. With multiple primary relays (as many as three) and multiple backup relays (both zone 2 and zone 3), the existing system is heavily biased toward dependability. Examination of NERC data indicates that incorrect relay operations are involved in two third of major disturbances, not necessarily as the initiating event but as a contributing factor to cascading outages. The mechanism of "hidden failures" in relays underlies relay

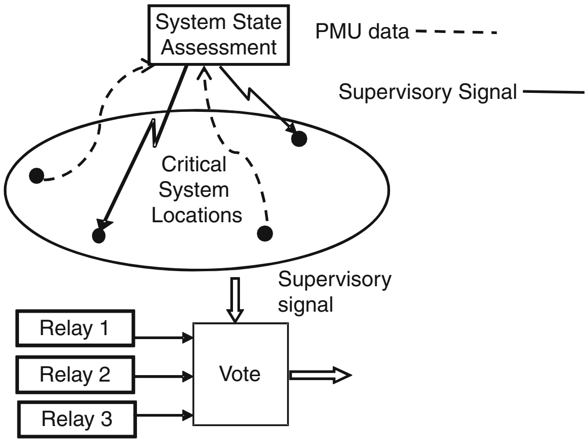


Fig. 5.9 An adaptive security/dependability protection scheme

involvement in major disturbances. A hidden failure is "a defect or error in relay that does not manifest itself immediately but which can cause a miss-operation when the system is stressed." The largest cause of hidden failures is thought to be maintenance. The Internet and Chemical plants also have maintenance-related hidden failures.

The solution to at least some relay involvement in cascading outages is to adjust the security/dependability balance when the system is stressed. One simple way to accomplish this is to require that two of the three relays see the fault before tripping the breaker. This voting procedure only requires altering the way the outputs of the primary relays are combined. The relay logic itself is left unchanged. The PMU contribution to process is to determine if the system is in a stressed condition. Figure 5.9 shows a voting scheme.

In a specific application, the location of the relays that will vote has to be identified. Important paths or tie lines whose loss would have a serious impact are obvious choices. Then, the location of the phasor measurement and the logic of translating measurements into a decision to vote have to be determined. One successful approach to these two problems is the use of decision trees. The tree is trained with a selection of a large number of scenarios where it can be determined that a vote would be beneficial combined with a similar set of scenarios in which voting is not necessary. For example, if the path included parallel lines, the loss of an additional line due to a hidden failure can have serious consequences. Many transient stability simulations have to be performed to determine conditions where voting is indicated. The tree is selected with data mining software from an array which has a row for each events and a column for every measurement that might possibly be used. All bus voltages and line currents in the area could be included in the matrix, for example. The last column has a 1 for voting and a 0 for not voting. The data mining software selects the measurements to be used to form a tree.

A tree is shown in Fig. 5.10. The grey boxes are splitting nodes while the white and textured boxes are terminal nodes. The first splitting node selects one

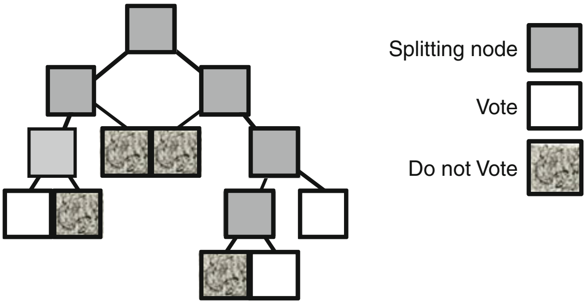


Fig. 5.10 A decision tree with five splitting nodes

measurement and tests that measurement value against a threshold. The remaining splitting nodes also use only one variable, and it is possible that the same variable can be reused in other splitting nodes with different γ's. The tree finds both the measurement m_k and the threshold γ. Typically, the initial splitting nodes for these power system problems are quite effective, and the splitting nodes lower in the tree are making fine corrections: $m_k \leq \gamma$ *or* $m_k > \gamma$ splitting logic.

Monitoring Approach of Apparent Impedances Toward Relay Characteristics

Relay settings are made at the time of commissioning of the substation and the protection system. Once made, these settings are generally not subjected to periodical review. Although this is not a universal practice, more and more power companies have limited manpower available for such tasks, and it is usually the case that the relay settings are seldom if ever revisited.

It is a fact that many of the relay settings are based upon certain assumptions made about the power system configuration and load levels. This is particularly true about the slower protection functions such as backup zones of distance relays, loss-of-field relays, etc. As years go by, the relay settings which depend upon system conditions may no longer be appropriate for the prevailing power system conditions because of the natural evolution of the power system. As the relay settings become inappropriate, the possibility of false trip of such relays becomes likely. One of the watershed blackout events is the 1965 blackout in North Eastern United States. The settings of some relays involved in this event were made 9 years before the event and had become inappropriate for the system conditions existing in 1965. Misoperation of these relays was a main contributing factor of this blackout.

PMUs employed for WAMS can be programmed to track the behavior of apparent impedance continuously and provide an alarm to the relay engineers that the apparent impedance trajectory recently (on recorded date and time) came within a prescribed distance of the trip characteristic. This is particularly effective when distance relays are used for the protection function. The concept is illustrated in Fig. 5.11.

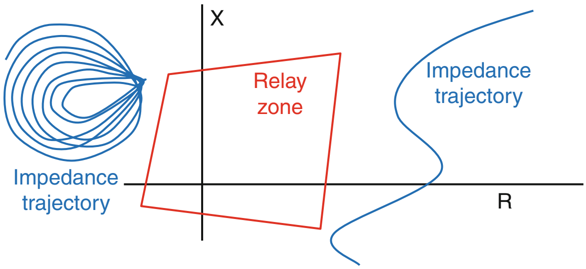


Fig. 5.11 Zone setting of the relay in question is shown in *red*. Impedance trajectories are shown in *blue*, and two types of trajectories – one corresponding to stability swing and the other to load changes – are shown

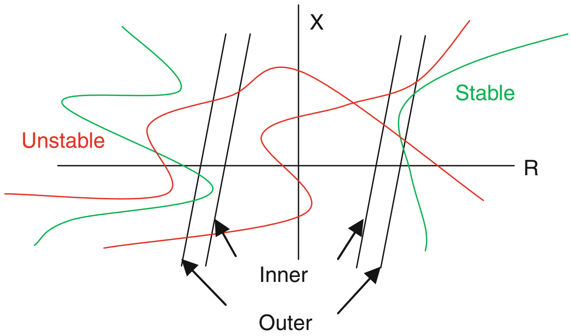


Fig. 5.12 Traditional out-of-step relay characteristic. All stable swings remain outside the inner zone while the unstable swings cross the outer and the inner zones in time which is shorter than the timer setting of the relay. Stable swings are shown in *green*, while unstable swings are shown in *red*

The figure shows that load changes as well as stability swings did indeed come close to the relay zone, and a message to this effect is sent to the relay engineer responsible for this setting. After reviewing the incident, the relay engineer may decide to review and modify the relay setting, or ignore the alarm confirming that the setting is in fact appropriate for the prevailing power system state.

Adaptive Out-of-Step

Out-of-step (OOS) relaying is used to determine if a major power system disturbance is likely to result in loss of synchronization between groups of generators in the system and lead to island formation of portions of the power system. The present practice is to use distance relays at the terminals of generators or on transmission lines which lie at the electrical center of expected system disturbances. The traditional OOS has a characteristic as shown in Fig. 5.12 with an inner zone and an outer zone in the relay impedance plane. Using large number of transient simulations performed on the power system, the settings of these relay zones are determined. The inner zone is such that no stable power swing crosses into it, while unstable swings are expected to cross the outer and inner zones in sequence. A timer is set somewhat greater than the largest dwell time of the unstable impedance trajectory between the two zones. The zone boundaries and the timer are then used to detect whether or not a prevailing disturbance will lead to instability.

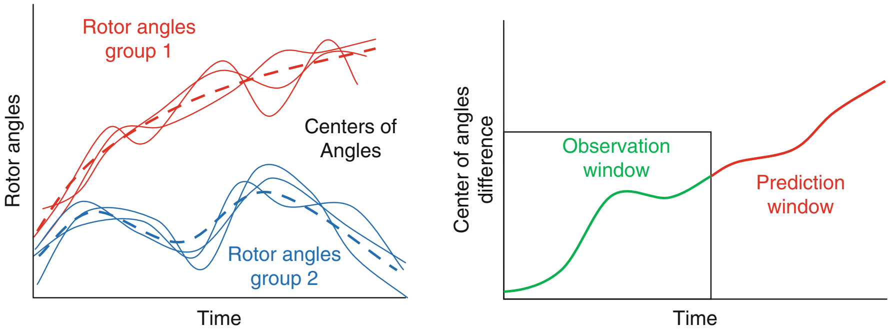


Fig. 5.13 Adaptive out-of-step relaying principle. Generator rotor angles are monitored to determine whether coherent groups are being formed. Once the coherent groups are formed, a prediction regarding the outcome of the swing can be made

The traditional out-of-step relays are often inadequate when the power system changes or when unanticipated outages occur. In such cases, the relay settings may not be appropriate to the prevailing system conditions, and the OOS relay is likely to misoperate.

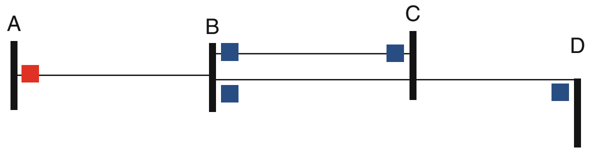
Adaptive out-of-step relaying principle proposes to use real-time measurements to determine whether or not an evolving disturbance is going to lead to instability. The most promising real-time measurements to achieve this goal are the phasor measurements provided by the PMUs. In this approach, the first step is to detect the formation of coherent groups of generators and, once the coherent groups have been determined, to predict the likely outcome of power swings between the coherent groups. In order to determine coherency between generators, it is necessary to track the rotor angles of generators in time as the disturbance evolves. The rotor angles are determined from phasor measurements performed at the terminals of the generators and then using the generator equivalent circuit to determine rotor angles. In many cases, it is sufficient to track the behavior of the positive sequence voltage angle at the generator terminals. Figure 5.13 illustrates the concept of this type of adaptive out-of-step relaying.

It is of course possible that there are some unusual disturbances whereby it is not possible to identify the coherent groups or make a successful prediction based upon an observation window. However, a success rate of around 90% seems to be possible in most power systems and should be considered to be a good outcome of the adaptive out-of-step relaying principle.

Supervision of Backup Zones

Distance relays are used to protect transmission lines. It is common practice to use three zones of distance relays to cover the complete transmission line (with zones 1 and 2) and provide a backup protection for neighboring transmission lines with

Fig. 5.14 Supervising zone 3 of the distance relay at station A. It is assumed that PMUs exist at stations B, C, and D



zone 3. The three zones are given different operating times – zone 1 being the fastest, zone 2 having an operating time of about 300 ms, and zone 3 operating in about 1 s, thus giving enough time for relays of the neighboring lines to operate if there is a fault on those lines. Backup zones of protective relays – in particular the third zone of distance relays – are known to be encroached upon by load swings during system disturbances. As load excursions in the relay protective zones lead to incorrect trips, this usually leads to a worsening situation and accelerates the approach to cascading system failures. Some engineers have recommended getting rid of these overreaching zones completely in order to avoid false trips of this type. However, there are documented cases [16] where it is found to be essential to have zone-3 protections in order to back up neighboring circuits when their primary protection fails for some reason [16]. It then becomes necessary to consider ways in which the overreaching zones of distance relays can be made secure against false trips due to load excursions.

Consider a portion of a power system shown in Fig. 5.14. Zone 3 of the distance relay at station A (shown in red) is assumed to be picked up because of load excursion during a power system contingency. The decision to be made is whether the zone-3 pickup is due to a fault on lines BC or BD or is in fact caused by a load excursion. If it is a fault on lines BC or BD, at least one of the PMUs located at stations B, C, or D (shown in blue) will indicate a zone-1 fault. If none of the PMUs confirm the existence of such a fault, then zone 3 of the relay at A must be blocked. As zone-3 operating times are of the order of 1 s, there is ample time to get the information from stations B, C, and D to the relay at station A. It should be noted that if an unbalanced condition is detected at station A, an unbalanced zone-3 fault is indicated, and the blocking of its operation is not appropriate. As load excursions are balanced phenomena, the blocking logic based upon inputs from B, C, or D is appropriate only under balanced network flow conditions.

Adaptive Loss-of-Field

Large generators in power systems are generally protected against operating with reduced field current. The problem faced by these generators is instability when

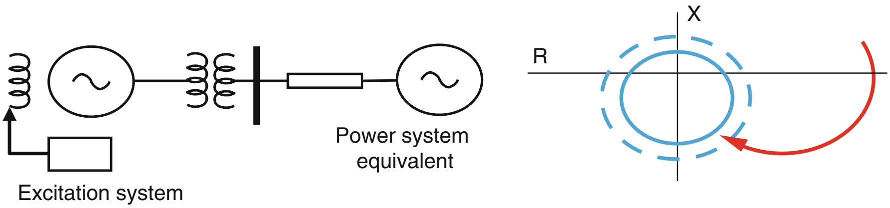


Fig. 5.15 Generator with its excitation system connected to power system. Characteristic of the LOF relay connected to generator terminal is shown on the right

the field current is suddenly reduced due to some problem in the excitation circuit. The traditional protection against loss-of-field (LOF) uses offset impedance relays connected at the terminals of the generator. The relay settings are determined by the impedance of the generator and the equivalent impedance (Thévénin impedance) of the power system to which the generator is connected. A typical loss-of-field characteristic is shown in Fig. 5.15.

The LOF relay setting consists of two concentric offset impedance circles as shown in the figure in blue color. The inner circle is the actual stability limit, whereas the outer circle shown by dotted line provides an alarm to the operator to take some corrective action before stability limit is reached. The center and radius of the circles are determined by the machine impedance (including the step-up transformer impedance) and the Thévénin impedance of the power system equivalent. A typical impedance trajectory indicating a loss-of-field condition is shown in red: the start of the trajectory is in the first quadrant where the pre-disturbance load is assumed to exist, and as the field current decreases, the impedance trajectory moves in the fourth quadrant and may enter one of the zones of the relay.

During a major disturbance on the power system as transmission lines are lost due to faults or other contingencies, the power system Thévénin impedance may undergo significant changes. These changes should be taken into account and the relay characteristics modified accordingly. If this is not done, it is likely that instability of the generator could result even though the impedance trajectory has not entered the zones set according to "system normal" conditions. An adaptive LOF relay would track the behavior of the power system as it undergoes changes during system disturbances and correct the relay settings automatically to reflect the prevailing state of the Thévénin impedance. In general, the network changes remote from the generator do not affect the Thévénin impedance significantly, and there may be just a few network configurations for which the relay characteristic needs to be changed. The possible contingencies and their corresponding relay settings could be pre-stored as various setting groups in the LOF relay, and when one of these contingencies actually occurs on the system, the relay setting changes to the appropriate group.

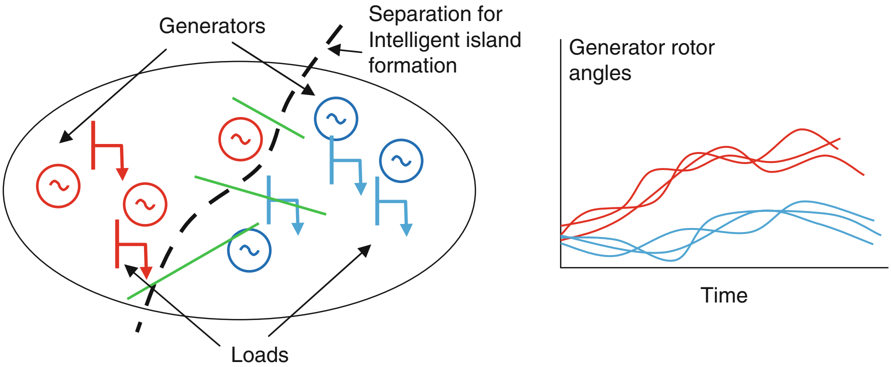


Fig. 5.16 Intelligent islanding principle. Coherency of groups of generators is established, and then possible island with those generators is identified

Intelligent Islanding

When subjected to catastrophic events, generators in the power system may lose synchronism with each other so that they can no longer continue to operate as components of a single power system. Usually, generators tend to maintain synchronism within individual groups, which could get separated from the rest of the power system. Several islands may be formed in this fashion, each island stabilizing as a separate power system with its own generation, transmission system, and load. If the formation of islands is allowed to happen in an uncontrolled fashion, it is possible that unsustainable islands would be formed, and some islands or the entire power system may be subjected to a blackout. This is the motivation for implementing an intelligent islanding scheme.

The first step in such a scheme is to identify groups of generators which remain coherent as a precursor to forming an island. This concept is illustrated in Fig. 5.16.

Consider the power system in Fig. 5.16, which has been subjected to a significant contingency, and as a result, groups of generators shown in red and blue develop rotor movements as illustrated in the swing curves shown on the right. Based upon this movement of rotors, it can be concluded that the group of blue generators is a coherent group, and the red generators form another coherent group. The next step is to match the capacity of blue generators with loads shown in blue, thus making up the structure of the proposed island. The red loads are then teamed with red generators, which are also approximately matched in generated power and load. Having identified load and generation match, the next step is to identify the least number of lines (shown in green) which when opened will create two islands which have the potential to survive as two independent power systems, which can be re-synchronized into a single power system at a later stage.

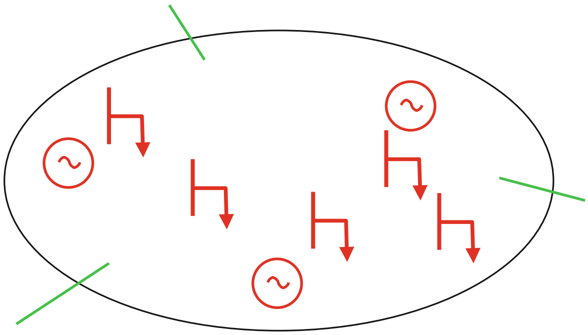


Fig. 5.17 Intelligent load shedding principle. Changes in tie line flows are used to determine load shedding requirements to balance load and generation within the system

Intelligent Load Shedding

Most modern power systems are equipped with an underfrequency load shedding scheme by which certain amount of load is shed in order to match available generation with load it can serve. This may become necessary when a block of generation is lost due to faults or other causes, or when the power system has broken up into islands with unequal generation and load. In this scheme, the load shedding is accomplished only after the frequency of the system changes because of the load-generation mismatch. A more intelligent approach to load shedding would be to anticipate the possibility of a load-generation mismatch developing, which may (if unchecked) lead to system islanding. Such an approach requires that an estimate of the load-generation mismatch be formed as soon as it takes place and then shed an appropriate amount of load without waiting for the system to break up into islands and the island frequency to change.

Consider a generic power system shown in Fig. 5.17. It is a part of an interconnected power system, and it has several tie lines (shown in green) connecting it to the rest of the grid. As the system undergoes a change – such as a loss of some generation – a potential for load-generation imbalance within the boundary of the power system occurs. If changes in the tie line flows are monitored by the Wide Area Monitoring System, it reflects the contributions made by the rest of the grid to aid the power system in riding through this disturbance. From the changes in the tie line flows, an estimate of the impending load-generation imbalance in the system can be made. If it is determined that the potential imbalance is significant, and that if not corrected immediately may lead to islanding of the power system, load shedding could be initiated by supervisory control without waiting for the frequency to decay.

A number of simulation studies need to be performed on the complete grid with various scenarios of generation loss. For the cases which lead to islanding in the simulation studies, different amounts of loads to be shed to prevent the formation of island can be established. The results of these studies can then be used as an aid in determining the load shedding required in actual cases of generation loss.

Power System Control

Prior to synchrophasor measurements, essentially all control in the interconnected power system was based on local measurements. Control that responded to the power system frequency was a possible exception since frequency is a global quantity viewed on a long time scale. Many techniques were developed to deal with the limitation of local measurements. A variety of equivalents, coherent groups, and reduced order models were use to develop control strategies. The existence of wide area measurements with time tags opened up the possibility of control based on some remote measurements. Full state feedback as employed in smaller systems is still impossible, but feedback of important variables can be considered. The choice of the control strategy and placement of remote measurements are problem dependent and are current research topics. Concerns with latency in the signals, the performance of data concentrators, and the design of communication networks have delayed control applications more than some other areas.

Control of Sustained Oscillations

Very low frequency lightly damped low-frequency oscillation has been observed in large power systems for decades. The interactions between groups of machines displaced by large distances tend to be at frequencies less than 1 Hz. The analysis of such modes is based on small signal linear models found by linearizing about an operating point. Such Inter-area oscillations are tolerated when they have sufficient damping but can become a serious threat when the damping starts decreasing. The evolution of a 0.27-Hz mode in the WECC disturbance in 1996 is representative. The oscillation began as 0.27 Hz with 7% damping. The tripping of a significant line altered the mode to 0.254 Hz with 3.46% damping which over the course of about 200 s became 0.252 Hz with 1.2% damping. Shortly thereafter, another line tripped, a generator was dropped, and the mode became unstable [17]. In China, in 2008, two system-wide low-frequency-oscillation events occurred respectively in the South China and Central China grids [18]. A 0.4-Hz oscillation was a precursor to the 2003 Eastern China disturbance [18, 19]. The conventional approach to damping such oscillations is to employ a power system stabilizer (PSS). PSSs use local information such as accelerating power, the generator rotor speed deviation, or frequency deviation as input to the regulator to damp oscillations.

Modern digital power system stabilizers [20] still use local measurements of power and frequency and are aimed at single inter-area oscillations. There have also been studies including remote measurements in a coordinated multi-input environment [21, 22]. The number of remote measurements considered in these studies has been small compared to the number of such measurements that are possible. In rapidly growing systems such as the Chinese power system, the limitation of PSSs that are designed for specific modes is more apparent. The need to retune PSSs has prompted investigation of techniques to adapt PSS operation to changing system conditions [23, 24]. The most ambitious approach is to coordinate PSSs, FACTS devices, and DC lines in stabilizing inter-area oscillations [25–28]. Linear feedback based on various robust control techniques have been employed to deal with power system nonlinearity and uncertainty. Time delays have been modeled as uncertain parameters [25], unmeasured portion of the system was represented by unmodeled dynamics [27], and LMI techniques used to design robust H_2/H_∞ controllers [28–33].

Control of Large Oscillations

Faults that remain on the system longer than a "critical fault clearing time" can cause oscillations large enough that the nonlinear nature of the system is exposed. The oscillations are described by a coupled set of nonlinear differential equations. Depending on the complexity of the representation of the generators, each machine can be described from 2 to 20 or more state variables. At the simplest level, the "classical" machine model involves the rotor angle and speed (the derivative of the angle). If the rotor angle is denoted by δ, the "swing" equation for a single machine in a per-unit system takes the form:

$$M\ddot{\delta} + D\dot{\delta} = P_m - P_e$$

where M is the inertia of the machine, D is the damping, P_m is the mechanical input power, and P_e is the electrical output power. The equation is nonlinear since the electrical power is a function of angle differences, i.e., P_e depends trigonometrically on δ. In equilibrium, $P_m = P_e$, and δ is constant. The equal area criterion in section "Adaptive Out-of-Step" is developed from examination of the swing equation for a single machine. Even in using reduced order modeling in large systems, there are hundreds of coupled nonlinear differential equations to be solved in order to study the transient stability problem. The equations are coupled by the P_e term because every machine connected to machine n has an electrical power contribution to P_e. If the fault duration is too long, the system is moved away from equilibrium on the "fault on trajectory" and begins to oscillate or swings when the fault is cleared. In large systems, the time for one period of a transient swing is a second or more, suggesting that time is available for PMU measurements to be used in control of these oscillations. The means available for control are somewhat limited. Fast valving of steam turbines; insertion of a dynamic brake; generator, reactor, and line switching; control of DC line flow; and FACTS devices are possible. Specific applications of PMU inputs to some of these controls have been reported [34–40]. The use of PMU measurements in these control schemes should improve their performance.

In one study, the control involved the DC lines and was discrete in nature. The PMU measurements were mapped into regions where specific discrete control actions were taken [41]. Many off-line simulations were used to generate the mapping, but no time was involved in real-time computing a control action.

Remedial Action Schemes

Remedial Action Schemes (also known as Special Protection Schemes or System Integrity Protection Schemes – SIPS) are designed to address a problem caused by a relaying action. For example, the loss of one of three parallel lines could overload the remaining two lines. The scheme might not always be enabled but could be armed based on system conditions. If the flow in the lines was large enough, the control scheme could drop load and/or generation when a relaying action removed any of the parallel lines. In some cases, operators arm the RAS scheme. All SIPS are essentially specially designed control and protection systems and can be enhanced with PMU input [42]. The addition of PMU information for SIPS could be managed using the decision tree approach used for adaptive security/dependability in section "Adaptive Security/Dependability" The proper coordination of large numbers of these schemes is an even more challenging problem.

System Restoration

Synch check relays are used to ensure that two AC systems are synchronized. For a system to be synchronized, the frequency, phase angle, and voltage must be within preset limits. Wide area measurements could be used to perform these same functions across breakers used to close tie lines between islands reclosing when the angle differences are within acceptable bounds. If the angles exceed acceptable limits, a generation-load rescheduling within the islands could bring the quantities within limits. The large number of unsuccessful attempts to reclose in Europe in November 2006 gives testimony to the need for real-time angle measurements in restoration [33]. Restoration could only be achieved after the phase angles of separated areas become acceptable.

Artificial Neural Networks (ANN) have been proposed to aid in system restoration [45]. The ANNs can be trained to determine island boundaries for restoration and to determine a sequence of switching operations which would lead to restoration, taking into account overvoltages due to light load conditions and problem caused by cold-load pickup.

Future Directions

Wide Area Measurement Systems utilizing Phasor Measurement Units have become the power system sensors of choice. These systems deliver precise simultaneous measurements of key power system variables from which reliable real-time models of power systems can be created and intelligent monitoring, protection, and control decisions could be implemented. These measurements also offer one of the most reliable tools for postmortem analyses of catastrophic events taking place on the power systems. From such analyses follows an understanding of realistic models of power system elements and more realistic simulation tools.

The future of this technology holds the promise that power systems of the future will be made more secure – that is, they will be less immune to catastrophic failures – and in rare cases when such failures do occur, their impact will be considerably reduced in its physical extent and duration. This will be made possible through protection and control tasks which take into account precise knowledge of the current state of the system and take actions which are best suited to the prevailing power system conditions.

It is already clear that the technology is making an impact on all major power producers throughout the world. As the world brings into the mainstream of electric power establishment greater number of alternative energy sources, dependence on this technology is going to be even greater as engineers face the challenge of integrating these newer-generation systems which behave in unpredictable and intermittent fashion. Application of this technology in coming years will usher in an era of cleaner, abundant, and reliable supply of electricity to future generations.

Bibliography

Primary Literature

1. Dopazo JF et al (1975) Implementation of the AEP real-time monitoring system. IEEE Trans Power Apparatus Syst 95:1618–1629
2. Thorp JS, Phadke AG, Karimi KJ (1985) Real-time voltage phasor measurements for static state estimation. IEEE Trans Power Apparatus Syst 104:3098–3107

3. Phadke AG, Thorp JS, Karimi KJ (1986) State estimation with phasor measurements. IEEE Trans Power Syst 1:233–241
4. Nuki RF, Phadke AG (2005) Phasor measurement placement techniques for complete and incomplete observability. IEEE Trans Power Deliv 20:2381–2388
5. Gou B, Abur A (2001) An improved measurement placement algorithm for network observability. IEEE Trans Power Syst 16:819–824
6. Abur A (2005) Optimal placement of phasor measurements units for state estimation. PSERC Publication 06–58, Oct 2005
7. Zhou M (2008) Phasor measurement unit calibration and applications in state estimation. Ph. D. dissertation, Virginia Tech
8. Jeffers R (2007) Wide area state estimation techniques using phasor measurement data. Virginia Tech Report prepared for Tennessee Valley Authority
9. Centeno V, De La Ree J, Phadke AG, Michel G, Murphy RJ, Burnett R (1993) Adaptive out-of-step relaying using phasor measurement techniques. IEEE Comput Appl Power 6:2–17
10. Horowitz SH, Phadke AG, Thorp JS (1988) Adaptive transmission system relaying. IEEE Trans Power Deliv 3:1436–1445
11. Rockefeller GD, Wagner CL, Linders JR, Hicks KL, Rizi DT (1988) Adaptive transmission relaying concepts for improved performance. IEEE Trans Power Deliv 3:1446–1458
12. Hedding RA, Mekic F (2007) Advanced multi-terminal line current differential relaying and applications. In: Protective Relay Engineers, 60th annual conference, College Station, 27–29 Mar 2007, pp 102–109
13. Lien K-P, Liu C-W, Jiang J-A, Chen C, Yu C-S (2005) A novel fault location algorithm for multi-terminal lines using phasor measurement units. In: Proceedings of the 37th annual North American power symposium, Ames, lowa, 23–25 Oct 2005, pp 576–581
14. Lin Y-H, Liu C-W, Jiang J-A (2000) An adaptive fault locator for transmission lines tapped with a source of generation-using synchronized voltage and current phasors, pp 1379–1383
15. Yu C-S, Liu C-W, Yu S-L, Jiang J-A (2002) A novel adaptive PMU-based transmission-line relay-design and EMTP simulation results. IEEE Trans Power Deliv 17:33–46
16. Horowitz SH, Phadke AG (2006) Third zone revisited. IEEE Tran Power Deliv 21:23–29
17. Hauer AJF, Trudnowski DJ, DeSteese JG (2007) A perspective on WAMS analysis tools for tracking of oscillatory dynamics. In: IEEE Power Engineering General meeting, Tampa, 24–28 June 2007, pp 1–10
18. Dong M, Yang D, Huang Y (2008) Analysis on the low frequency oscillation incidents measured by WAMS of central China power grid during the 2008 ice hazard. Cen China Electr Power 21:22–25
19. Zhu F, Liu ZH, Chu L (2004) Achievement and experience of improving power system stability by PSS/excitation control in China. In: IEEE Power Engineering Society general meeting, Denver, 10 June 2004, pp 1767–1771
20. Kamwa I, Grondin R, Trudel G (2005) IEEE PSS 2B versus PSS4B: the limits of performance of modern power system stabilizers. IEEE Trans Power Syst 20:903–915
21. Kamwa I, Gerin-Lajoie L (2000) State-space system identification-towards MIMO models for modal analysis and optimization of bulk power systems. IEEE Trans Power Syst 15:326–335
22. Zhang Y, Bose A (2008) Design of wide–area damping controls for interarea oscillations. IEEE Trans Power Syst 23:1136–1143
23. Yu GL, Zhang H, Xie H, Wang CG (2007) Wide-area measurement-based robust control of power system considering signal's delay and incompleteness. In: Power Engineering Society general meeting, Tampa, 24–28 June 2007
24. Hu G, He R, Yang H, Wang P, Ma R (2005) Iterative Prony method based power system low frequency oscillation mode analysis and PSS design. In: Transmission and distribution conference and exhibition: Asia and Pacific, Dalian, 2005, pp 1–6
25. Gibbard MJ, Vowles DJ, Pourbeik P (2000) Interactions between, and effectiveness of, power system stabilizers, and FACTs device stabilizers in multimachine systems. IEEE Trans Power Syst 15:748–755

26. Yu Gl, Zhang BH, Xie H, Wang GC (2007) Wide-area measurement-based nonlinear robust control of power system considering signal's delay and incompleteness. In: Power Engineering Society general meeting, Tampa, 24–28 June 2007
27. Li X, Yan Q, Hu Y (2008) Decentralized coordinated robust adaptive control for AC/DC interconnected power system based on WAMS. IEEE Asia-Pacific Conf Circuits Syst 2008: 1896–1899
28. Dou C, Jin S, Bo Z, Jia Q, Xue H (2007) Decentralized stabilizer design for model-based uncertain large interconnected power systems based on WAMS. In: IPES, Singapore, 3–6 Dec 2007, pp 799–806
29. Rao PS, Sen I (2000) Robust pole placement stablizer design using linear matrix inequalities. IEEE Trans Power Syst 15:313–319
30. Soliman M, Emara H, Elshafei A, Bahga, A, Malik OP (2008) Robust output feedback power system stabilizer design: an LMI approach. In: IEEE Power and Energy Society general meeting conversion and delivery of electrical energy in the 21st century, Pittsburgh, 20–24 Jul 2008, pp 1–8
31. De Campos VAF, Da Cruz JJ, Zanetta LC (2006) Pole placement and robust adjustment of power systems stabilizers through linear matrix inequalities. In: Power systems conference and exposition, Atlanta, 29 Oct–1 Nov 2006, pp 2180–2187
32. Bensenouci A, Abdel Ghamy AM (2007) Mixed H∞/H2 with pole placement design of robust LMI-based put feedback controllers for multi-area load frequency control. In: EUROCON, Warsaw, 9–12 Sept 2007, pp 1561–1566
33. Jabr RA, Pal BC, Martin N (2010) A sequential conic programming approach for the coordinated and robust design of power system stabilizers. IEEE Trans Power Syst 25:1627–1636
34. Rostamkolai N (1986) Adaptive optimal control of AC/DC systems. Ph.D. dissertation, Virginia Tech
35. Manansala EC (1989) Adaptive power system control. Ph.D. dissertation, Virginia Tech, Aug 1989
36. Rostamkolai N, Phadke AG, Thorp JS, Long WF (1988) Measurement based optimal control of high voltage AC/DC systems. IEEE Trans Power Syst 3:1139–1145
37. Manansala EC, Phadke AG (1991) An optimal centralized controller with nonlinear voltage control. Electr Mach Power Syst 19:139–156
38. Mili L, Baldwin T, Phadke AG (1991) Phasor measurements for voltage and transient stability monitoring and control. Workshop on application of advanced mathematics to power systems, San Francisco, 4–6 Sept 1991
39. Snyder AF et al (1988) Inter-area oscillation damping with power system stabilizers and synchronized phasor measurements. In: PowerCon 1988, China
40. Smith MA (1994) Improved dynamic stability using FACTS devices with phasor measurement feedback. MS thesis, Virginia Tech
41. Rovnyak S, Taylor CW, Thorp JS (1995) Real-time transient stability prediction–possibilities for on-line automatic database generation and classifier training. In: 2nd IFAC symposium on control of power plants and power systems, Cancun
42. Madani V, Taylor E, Erwin D, Meklin A, Adamik M (2007) High speed control scheme to prevent instability of a large multi-unit power plant. In: Protective Relay Engineers, 2007: 60th annual conference, Clemson power system conference, pp 271–282
43. Sattinger W (2005) Developments in UCTE and Switzerland WAMC course at ETH Zürich, 30 Aug–1 Sept 2005
44. ENTSOE (2003) European network of transmission system operators for electricity. Final Report of the Investigation Committee, 28 Sept 2003 Blackout in Italy. https://www.entsoe.eu/index.php?id=59
45. Bretas AS, Phadke AG (2003) Artificial neural networks in power system restoration. IEEE Trans Power Deliv 18:1181–1186

Books and Reviews

Horowitz SH, Phadke AG (2008) Power system relaying, 3rd edn. Wiley, Chichester/Hoboken

IEEE Standard C37.118-2005 (Revision of IEEE Std 1344–1995) IEEE standard for synchrophasors for power systems

Kundur P (1994) Power system stability and control. McGraw-Hill, New York

Phadke AG, Thorp JS (2008) Synchronized phasor measurements and their applications. Springer, New York

Phadke AG, Thorp JS (2009) Computer relaying for power systems, 2nd edn. Wiley, Chichester

Rogers G (2000) Power system oscillations. Kluwer, Norwell

Chapter 6
Smart Grids, Distributed Control for

Frank Kreikebaum and Deepak Divan

Glossary

Flexible AC transmission system (FACTS)	A system deployed on the electrical network to control one or more parameters of the network. FACTS is typically realized with solid-state or mechanical switches.
Optimal power flow (OPF)	A method to control generation and transmission assets to minimize cost of operation, operate assets at or below rated values, and meet reliability requirements.
Reactive power	One of the two forms of power in AC power transmission, reactive power is the energy stored in magnetic and capacitive devices that is returned to the system every cycle. Reactive power is required to maintain grid functionality and is measured in (volt-ampere reactive) VARs. By definition, capacitors generate reactive power, and inductors consume reactive power.

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3

F. Kreikebaum
Georgia Institute of Technology, Atlanta, GA, USA
e-mail: frankkreikebaum@yahoo.com

D. Divan (✉)
School of Electrical and Computer Engineering, Georgia Institute of Technology,
Atlanta, GA, USA
e-mail: deepak.divan@ece.gatech.edu

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*,
DOI 10.1007/978-1-4614-5830-2_6,

Definition of Distributed Control for Smart Grids

Distributed control for smart grids is the use of distributed grid assets to achieve desired outcomes such as increased utilization of transmission assets, reduced cost of energy, and increased reliability. Distributed control is a key enabler to meet emerging challenges such as load growth and renewable generation mandates.

Introduction

The utility grid is a massive system with tens of thousands of generators, hundreds of thousands of miles of high-voltage transmission lines and millions of assets such as transformers and capacitors, all working with split-second precision to deliver reliable electrical energy to hundreds of millions of customers. The grid was designed at a time when electromechanical controls and generator excitation control were the only available control handles to keep the system operating. In addition, the inability to guide electricity flows and to store electricity inexpensively forced the adoption of rules that distorted market operation, and created inefficient use of assets. The decision of the US government to make electricity a universal right of the people and a regulated industry, further removed drivers that moved the industry toward effective and competitive operation. The result of these technology limitations and policy structures that were created, with the best of intentions, is that the electricity markets work ineffectively at best.

The electricity industry asset base in the USA is worth an estimated $2.2 trillion in terms of replacement value. Global and US electrical demands are expected to rise 80% and 24%, respectively over the next 20–25 years. In the USA, if grid-enabled vehicles (GEVs) are widely adopted, total electrical demand could be 45% higher in 2035 than 2008. Mandates for renewable energy are expected to require a doubling in annual transmission investment yet will lower utilization of the transmission system. A ubiquitous roll-out of smart grid functionality would provide better utilization of the transmission and distribution system, reduce the investment required to meet renewable mandates, and raise reliability. However, there is no economic basis for implementing such a far-reaching transformation. It is however possible, with correctly defined priorities, to implement an upgrade of selected portions of the grid, to achieve a large part of the important gains. Selective introduction of newer technologies that allow dynamic granular control (DGC) of voltage and power flows on the grid can enable a much more efficient use of grid assets, minimizing the need to build new transmission lines to accommodate variable generation resources such as wind and solar.

Such control capability will transform the electricity market, allowing transactions between willing generators and users, along pathways that have the capacity to handle more power. It will directly mitigate problems of cost allocation that have plagued transmission-line building. It will reduce the cost of absorbing more wind and solar energy, and of adopting GEVs to improve energy security and to reduce carbon emissions. This control cannot be implemented at the traditional generation excitation controls, but has to be implemented at various points on the grid, so that the utilization of diverse grid assets can be improved substantially. Such control will necessarily be distributed in nature, and points to a future vision of grid control.

Distributed control is a key enabler to meet emerging challenges in the electric power sector. This entry begins by surveying the emerging challenges. It then discusses general methods for two types of distributed control, namely VAR control and power flow control. Next, the technologies currently available to realize VAR control and power flow control are discussed. It then surveys emerging technologies and methods before concluding.

Emerging Challenges

Load Growth

Globally, electrical energy demand is expected to grow 2.5% per year from 2006 to 2030 with total demand rising from 15,665 TWh in 2006 to 28,141 TWh in 2030 [1]. Worldwide generation capacity is expected to grow 2.3% per year from 2006 to 2030, rising from 4,344 to 7,484 GW [1]. The DOE Energy Information Agency (EIA) expects US electrical load to increase 1% annually to 2035, a 24% increase in annual demand relative to 2010 demand [2]. These projections include negligible amounts of GEVs with electricity supplying less than 3% of global transport energy and 0.2% of US light-duty transit sector energy in 2030 and 2035, respectively [1, 3]. Historically, load growth has required investment in generation as well as the transmission and distribution systems. Utilities are facing pressure to meet this load growth at low cost to consumers, a challenge given high costs for fuel and materials.

Challenges Permitting Urban Generation and Transmission

The need for distributed control can be mitigated through the installation of generation in load centers or new transmission connecting distant generation with load centers. Siting generation in load centers is difficult due to noise, emissions, viewshed concerns, land acquisition cost, and the limited capacity of the urban fuel delivery system. In addition, generator cooling water availability is projected to be limited in many load centers [4]. A study in the USA shows that 19 of the 22 counties identified as most at risk for water shortage due to electricity generation are located in the 20 fastest growing metropolitan statistical areas.

Construction of new transmission to supply load centers is also difficult. Concerns include viewshed, land acquisition cost, and electromagnetic radiation. High-voltage transmission lines require more than a decade to build. Also, the allocation of cost is problematic, especially for lines that cross state and utility boundaries. Finally, the construction of new lines increases the MW-miles of line serving a given amount of load, decreasing rather than increasing utilization of the existing system, leading to cost increases and inefficiencies.

Policy Drivers for Renewable Generation

Policies are driving the adoption of renewable generation around the world. China aims to increase renewable energy from 7.1% of total electrical energy in 2005 to 20% in 2020 with the installed wind capacity rising from 1,260 MW in 2005 to 30,000 MW in 2020 [5]. Grid operators in China are required to accommodate renewable energy, with prices for wind decided in an auction in which only wind plants participate [5]. In the USA, 29 states plus the District of Columbia have enacted binding renewable portfolio standards (RPSs), and 7 states have voluntary goals [6]. RPSs require a certain percentage of annual electrical energy demand to be met with renewable generation by a specified year. In addition, the US federal government incents the development of renewable generation through the Production Tax Credit (PTC) and the US Treasury Section 1603 Investment Tax Credit.

The renewable mandates stress the transmission system and require additional investment. One metric of this stress is the ratio of peak generation capacity to average power demanded. In 2008, the US ratio was 2.18. In the EIA 2035 reference scenario, which sources 5% of national electricity from nonhydro renewables resources, the ratio improves to 2.03. All things being equal, this reduction shows increased utilization of the generation fleet in 2035 relative to 2008 and lower unit cost of energy. If a 20% RPS is mandated, the ratio rises to 2.29, a degradation resulting in lower utilization in 2035 relative to 2008. So, while the 2035 nonrenewable case shows a 7% increase in utilization, the RPS case shows a 5% degradation. To avoid curtailment of renewables, transmission must be built to accommodate the peak power output of the renewable fleet.

Globally, both wind and solar photovoltaic generation have grown exponentially over the last fifteen years, as seen in Fig. 6.1. As seen in Fig. 6.2, the highest quality wind and solar resources in the USA are remote from load centers. Siting generation at these high-quality resources maximizes the plant owner's return on investment if the transmission network can accommodate the generated energy. A number of integration studies have been performed around the globe to assess the transmission and system operation impacts of wind and solar energy on the system [7–22]. Two studies covering large, multistate regions of the USA are the Eastern Wind Integration and Transmission Study (EWITS) and the Western Wind and Solar Integration Study (WWSIS). In EWITS, the design of the transmission build-out was iterated using a committee of stakeholders. Undiscounted transmission costs were $33–59

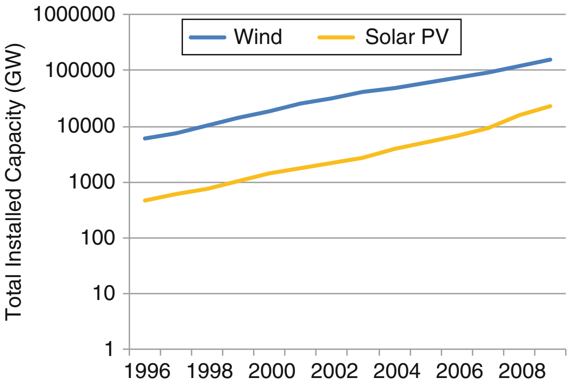


Fig. 6.1 Logarithmic plot of global cumulative wind and solar PV capacity installed [23]

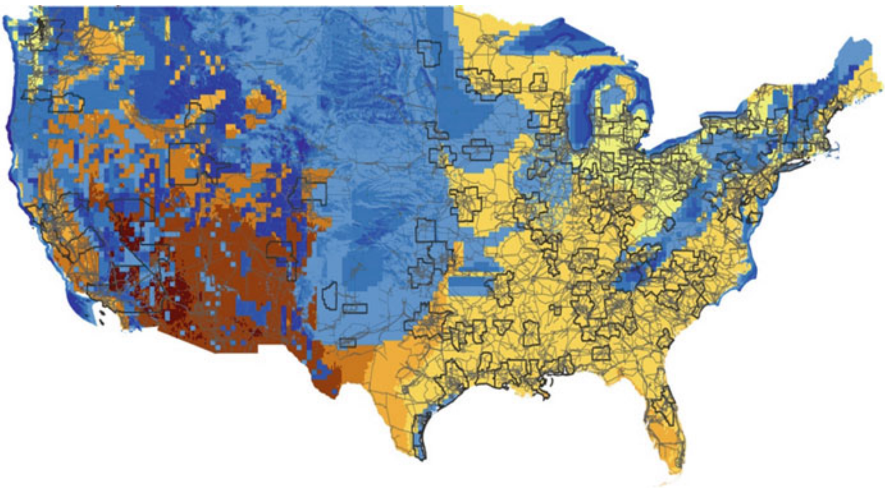


Fig. 6.2 Map of US wind and solar resources and major metropolitan areas. Solar resources are shown from *light yellow* to *brown*, with the highest resource sites in *brown*. Wind resources are shown from *light blue* to *dark blue*, with darker being more attractive. Only wind sites viable with current technology are shown. Major metropolitan areas are outlined in *black*. *Gray lines* in the background show the high-voltage transmission system

billion (2009$) higher than the reference case, which had minimal additional wind capacity. This amounted to $300–447 of added cost per kW of installed wind capacity. With the transmission build-out, wind curtailment averaged 7–11%, higher than current levels in the USA. In the WWSIS, Wyoming, Colorado, Montana, Arizona, and Nevada were supplied with up to 35% renewables. A simplified transmission build-out was developed to trade renewable energy among these states. The cost was $11B with a benefit-to-cost ratio of 0.9.

For a scenario in which 20% of US demand is met with renewable energy, the estimated transmission cost is $360 billion over 25 years, or $14 billion per year. This assumes the average distance between renewable generation and load is 1,000 miles, a reasonable scenario if renewable generation is installed in high resource areas in the Midwest and Southwest. Currently, total transmission investment, including long-distance and local transmission, is $9 billion per year. If renewable energy transmission investment substitutes for 50% of the current investment, total annual investment would be $18.5 billion per year, a 105% increase over current investment levels. This increased level of investment would need to be sustained for 25 years to supply 20% of projected US demand with renewable energy.

Policy Drivers for GEVs

Grid-enabled vehicles (GEVs) are experiencing a renaissance following their last resurgence in the 1990s. Mainstream manufacturers and new entrants offer or plan to offer GEVs spanning a broad price range. In the USA, GEVs are currently supported through federal and state tax credits. Proposals have been developed to electrify 75% of the miles traveled by the light-duty fleet by 2040 [24]. In Europe, high fuel taxes and a requirement that fleet average emissions drop from 160 to 95 g CO_2/km are likely to foster GEV development [24]. The Chinese government recognizes the ability of GEVs to improve energy security and has implemented a program to build charging infrastructure in the 13 largest cities. It also offers a tax incentive program for vehicles and buses on the order of $8,000 and $70,000 per vehicle, respectively [24]. The impact of GEVs on the power system is dependent on the level of GEV adoption, the charging model, and the level of coordination between the time of charging and the power system state. If 80% of the miles traveled by the US light-duty fleet are electrified by 2035, annual electrical demand is projected to increase 45% relative to 2008, compared to a 24% increase without GEVs. Uncoordinated charging will lead to overloading and accelerated aging of distribution assets [64]. The monitoring system for distribution assets is less developed than for transmission assets, making it difficult to proactively upgrade strained distribution assets. Without coordination of vehicle charging, significant new transmission and distribution investment will likely be required.

Differences Between the Electrical Network and Other Commodity Delivery Networks

In the USA, natural gas and petroleum pipelines have become less regulated over the last two decades. Before the 1990s, pipeline developers submitted plans for new pipelines to FERC. FERC selected which pipelines would be built based on its assessment of societal needs. It was assumed that FERC could not allow competition among pipelines. Following PUC CA v. CA 1990, FERC allowed more competition in the pipeline industry. Different rates could be charged to anchor customers, who supported pipeline construction at an early stage, and other customers who requested pipeline access after construction.

In petroleum pipelines, product differentiation is possible by separating shipments via a marker liquid called transmix. As of 2005, most shipment of oil was regulated by FERC, but refined products based on petroleum used market-based rates [25, 26]. However, market-based rates are the fastest growing rate type [25]. FERC permits the use of market rates on a case by case basis after ensuring that the pipeline does not have an unreasonable level of market power.

Due to deregulation, by 2000, the natural gas pipelines were no longer guaranteed a rate of return [27]. Users who reserved capacity were given firm transmission rights. Tariffs for firm capacity were regulated [28]. Remaining capacity was sold in bulletin boards at market rates. Owners of capacity can resell their capacity to realize arbitrage opportunities.

The electric network is considered a natural monopoly due to the inability of transmission line owners to control the flow of power through their lines. This lack of control means owners cannot take bids for the use of their lines, as is done in natural gas pipelines. The lack of control creates free-rider effects whereby entities benefit from investments made by others. Collectively, this creates a disincentive for transmission owners to upgrade their assets.

Reliability Challenges in Emerging Economies

A country-wide overview of reliability statistics was not identified for the emerging economies. Statistics for 1997–2008 were found for five utilities in Brazil, serving a combined electrified population of 389 million [29]. Statistics were also found for two power companies in India, the North Delhi Power Limited (NDPL) and the Bangalore Electricity Supply Company (BESCOM) [30]. Compared to the USA, the Brazilian utilities had eight times the annual outage duration and 14 times the annual outage frequency. The BESCOM system had 20 times the US outage duration. It is anticipated that continued economic growth will require more reliable supply of electricity, necessitating investment in emerging economies.

Distributed Control Techniques

Distributed control has been used to operate the electrical system since its inception. The initial subsection of this section will describe optimal power flow (OPF), which traces its history back to the earliest days of power system operation. Today's power system relies primarily on OPF to realize control. As discussed in the previous section, numerous challenges are emerging for power system investment and operation. Accommodating renewable energy and GEVs will likely require a response time not possible with traditional control techniques such as OPF. This section will introduce VAR control and power flow control. Realized with appropriate technologies, VAR control and power flow control can provide fast-responding control, called dynamic granular control (DGC), to meet the emerging challenges.

The techniques described in this section can be applied to both the transmission and distribution systems. Controllability of the distribution system has lagged behind that of the transmission system. This is in part due to the large number of distribution assets, relative to transmission assets. The number of assets increases the complexity and cost of controlling the distribution system. Unlike the transmission system, the distribution system has traditionally been operated as a radial network rather than a meshed network. This simplifies control but leads to lower reliability. Smart grid activities to date have been largely aimed at improving control of the distribution system to improve efficiency, increase capacity without new asset construction, and accommodate distributed generation.

Optimal Power Flow

Optimal power flow (OPF) is used by system operators and planners to minimize the total cost of system operation. OPF is the primary control technique in today's grid. The main control handles, or control actions, are adjustments of the real and reactive power injections of the generators. However, OPF can include other control handles, such as the settings of a phase-shifting transformer (PST). Although control decisions are typically made centrally, OPF is considered distributed control because the control actuators, such as generators and PSTs, are distributed throughout the system. OPF set points are not typically changed more frequently than every 5 min. OPF is configured to provide sufficient safety margins to accommodate unexpected events such as load forecast error, renewable generation forecast error, and contingencies. A contingency is when any one or more grid assets, such as a power line or transformer, suddenly go offline.

The realization of OPF is different in vertically integrated and market environments. In both, power flows are changed by directly changing the output power of the generators. In the absence of other power flow control technologies, OPF does not allow the control of flow in individual lines.

In a vertically integrated environment, a single utility is responsible for generation, transmission, and distribution in a given region. This utility owns all of the assets in the region and knows the costs and technical limitations of its assets. The inputs to the OPF are as follows:

- Generator parameters – For each generator, the maximum power output, minimum power output, bus to which the generator is connected, and a cost curve are provided to the OPF. Each cost curve describes the variable cost of operating the

unit at each potential operating point between minimum power and maximum power. Variable cost includes fuel and variable O&M costs.
- Transmission line parameters – For each transmission line, the line impedance values, nominal voltage, current rating, and terminal locations are specified.
- Transformer parameters – For each transformer, the transformer impedance values, nominal voltages, current rating, and terminal locations are specified.
- Load data – The expected demand at each bus is forecasted for each time step over which the OPF will be run.
- Contingency list – Normally, the OPF is run for a set of potential contingencies rather than all possible contingencies to reduce the solution time.
- Stability limits – The OPF does not typically compute the stability of the network endogenously. Rather, rules are provided to the OPF in the form of a nomogram or lookup table to ensure that unstable solutions are avoided.
- Reserve margin – The amount of surplus generation capacity that must be available to meet uncertainties in load and renewable forecasts as well as generator outages.

In a market area, an independent system operator (ISO) or regional transmission operator (RTO) runs the OPF to decide which generators will be used and at what level. The transmission network is typically owned by regulated entities, which may also own the distribution networks. Generators are independent of the owners of the transmission and distribution networks. Rather than cost curves, the generator owners submit bid curves to the ISO or RTO. The bid curves designate the minimum price generation owners are willing to accept to generate energy over the whole range of the generator output. In the simplest scheme, owners of the distribution network designate how much power their customers will require, and consumers are price takers. The other inputs to the OPF are the same as those used by the vertically integrated utility. Using the generator bids and forecasted demand, the ISO or RTO runs the OPF to compute the least cost dispatch of generators to serve the load and meet security requirements.

The economic impact of the lack of power flow control is visible in Fig. 6.3. In the figure, generators, each indicated by a circle with the letter "G" inside, are connected to bus 1 and bus 3. Load is connected at bus 3. Three transmission lines connect the three buses. Each line has a thermal rating of 1,000 MW. All transmission lines have the same impedance X. G1 is the cheapest generator. To minimize cost, G1 should serve the entire load at bus 3. However, due to transmission network constraints, G1 can only supply 1,500 MW. One thousand megawatts flows from bus 1 to bus 3 through line 1–3, and 500 MW flows from bus 1 to bus 3 via line 1–2 and line 2–3. The flow is less in line 1–2 and line 2–3 compared to line 1–3 because of the increased impedance. Because of this impedance difference, the flow through line 1–2 reaches the limit of 1,000 MW when the total power transfer is 1,500 MW. This sets the maximum amount of power G1 can supply to bus 3 even though 500 MW of unused capacity exists on line 1–2 and line 2–3.

OPF alone is limited to adjustments of generator output and is not able to resolve numerous challenges, including those described above. While the following

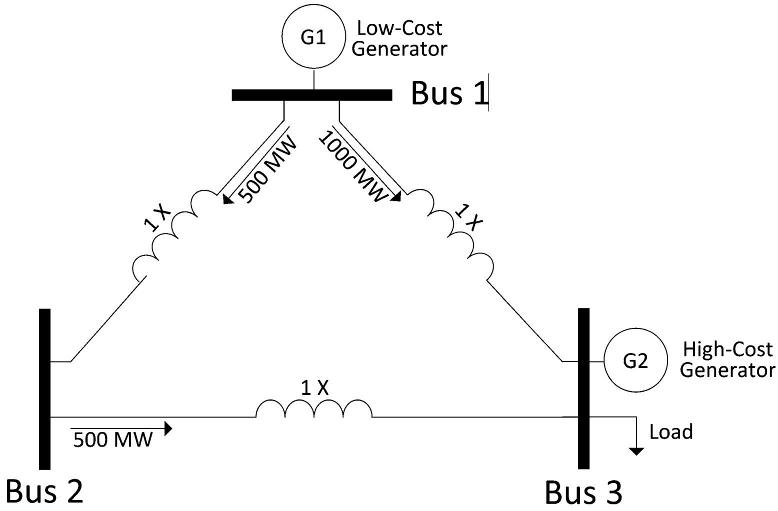


Fig. 6.3 Three-bus system showing power flows resulting from OPF control of generation

sections will describe some power flow control capabilities beyond generation control that are currently implemented, the majority of power today is controlled, inefficiently, through OPF control of generator set points.

VAR Control

VAR control provides a number of benefits to the system. First, it can be used to control the voltage profile along a transmission line, thereby increasing the maximum amount of power which can be transmitted in the line. It can also be used to decrease the reactive power which must be sourced at the endpoints of a line and reduce line losses. VAR control can also be used to improve voltage stability if the end of a power line does not have sufficient generation. VAR control, if appropriately fast, can improve transient stability. Improvement of transient stability also increases the power which can be transferred on the line. Finally, VAR control can be used to damp power system oscillations, averting damage to rotating machinery, increasing power transfer capability, and potentially improving stability.

Power Flow Control

Under certain simplifying assumption, the power flow between two buses of an electrical network is determined by Eq. 6.1. The power flow can be modified by modifying any of the parameters of the equation:

- V_1 and V_2 are the voltage magnitudes of the endpoints of the transmission line.
- δ is the angle difference between the voltage phasors at the endpoints of the transmission line.
- X is the reactance of the transmission line.
- P is the power transmitted over the transmission line.

Voltage changes alone cannot impact power flow in a large way, since the voltage is typically maintained within ±5% of a nominal value to avoid damaging generators, the transmission network, the distribution network, or customer equipment.

The following sections will detail the methods used to change power flows:

Power flow between two AC buses.

$$P = \frac{V_1 V_2 sin\delta}{X}. \tag{6.1}$$

Impedance Control

Impedance control of power flow aims to directly change the impedance, represented by the value X, as seen in Eq. 6.1. Technologies able to change impedance include the series mechanically switched capacitor (series MSC), the series mechanically switched reactor (series MSR), the thyristor-controlled series capacitor (TCSC), the static synchronous series compensator (SSSC), and the unified power flow controller (UPFC). These technologies will be discussed in more detail in section "Existing Distributed Control Technologies."

The benefit of impedance control is shown in Fig. 6.4, a modification of the three-bus system previously shown in Fig. 6.3. Here, a power flow controller able to change line impedance has been installed on line 2–3. Through an appropriate modification of the impedance, the power flow in all lines can be equalized, allowing up to 2,000 MW to be transferred between bus 1 and bus 3, compared to the 1,500 MW using generator control alone. This allows the entire load at bus 3 to be served by the low-cost generator, resulting in a reduction in the cost of energy.

Angle Control

Angle control aims to change power flows through the parameter δ as seen in Eq. 6.1. Technologies able to control the angle include the phase-shifting transformer (PST), also known as phase angle regulator (PAR), the variable frequency transformer™ (VFT), and the solid-state transformer. The power flow control of Fig. 6.4 can also be realized using angle control. The PST and VFT will be discussed in more detail in section "Existing Distributed Control Technologies." The solid-state transformer will not be discussed as it is not commercially available and is expected to have high cost.

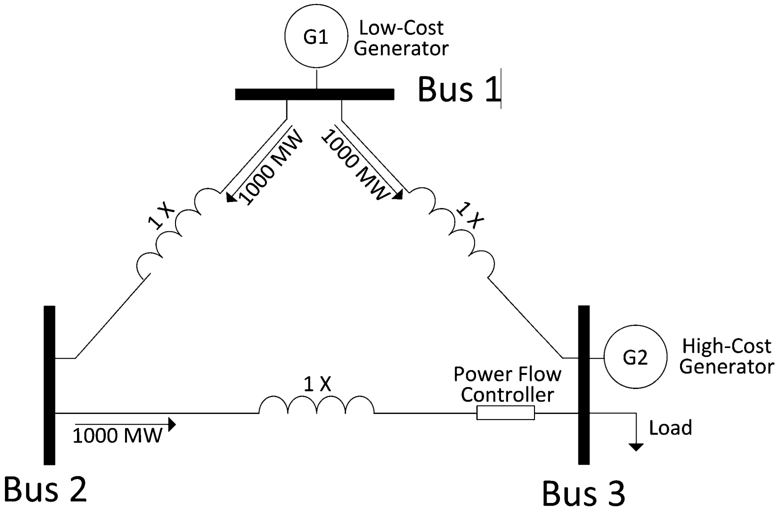


Fig. 6.4 Three-bus system with power flow controller installed on line 2–3. The OPF determines the optimal settings for the generator and power flow controller

Voltage Control

Angle control aims to change power flows through the parameter V_1 or V_2 as seen in Eq. 6.1. Technologies able to control voltage include the static VAR compensator (SVC) and the static synchronous compensator (STATCOM). The power flow control of Fig. 6.4 cannot be realized via voltage control although voltage control can be used for limited power flow control in more complicated networks.

DC Control

It is also possible to control AC power flows by converting from AC to DC and then back to DC. Two technologies include the high-voltage DC transmission (HVDC) and the back-to-back converter (B2B). Both will be discussed in more detail in section "Existing Distributed Control Technologies."

Existing Distributed Control Technologies

This section will discuss existing distributed control technologies for VAR control and power flow control. These technologies provide various levels of dynamic granular control (DGC). These technologies can be actuated through OPF for response times on the order of minutes or through separate control algorithms for response times on the order of microseconds.

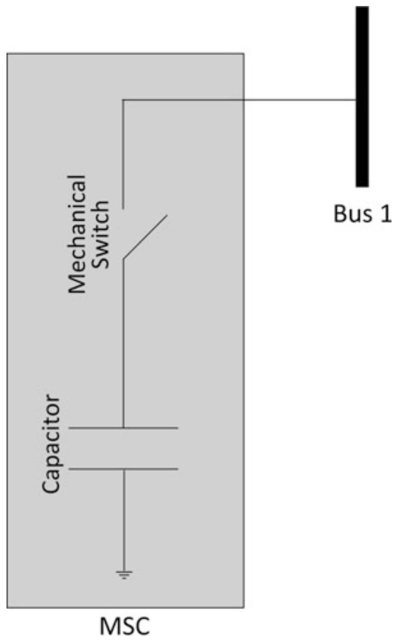


Fig. 6.5 Shunt mechanically switched capacitor (MSC) connected to bus 1

VAR Control

Shunt Mechanically Switched Capacitor (shunt MSC)

A mechanically switched capacitor (MSC), when connected in shunt at a bus, can provide VAR control by delivering capacitive VARs. A typical installation is shown in Fig. 6.5. Switching causes deterioration of the mechanical switch. Thus, MSCs are typically not actuated frequently. MSCs are ubiquitous. The cost for an MSC was $8–10/kVAR in the mid-1990s [31].

Shunt Mechanically Switched Reactor (shunt MSR)

A mechanically switched reactor (MSR), when connected in shunt at a bus, can provide VAR control by delivering inductive VARs. A typical installation is shown in Fig. 6.6. A circuit breaker is typically used to connect and disconnect the MSR due to the inductive load. As with MSCs, frequent actuation deteriorates the mechanical switching element. MSRs are widely used.

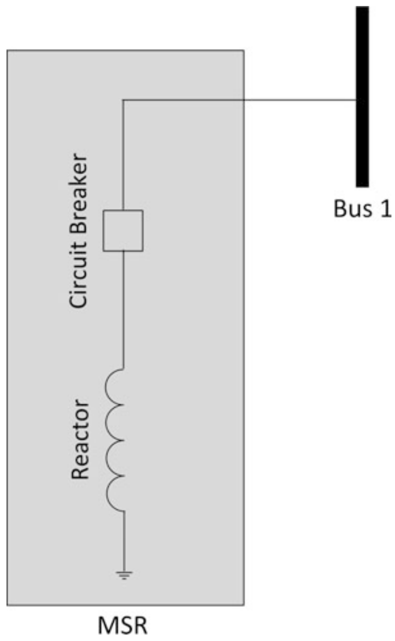


Fig. 6.6 Shunt mechanically switched reactor (MSR) connected to bus 1

Thyristor-Switched Capacitor (TSC)

A thyristor-switched capacitor (TSC), shown in Fig. 6.7, is a shunt capacitor which is switched in and out using a thyristor pair. The use of a thyristor pair, rather than a mechanical switch as in the MSC, allows for longer life. Also, a TSC can respond faster than an MSC, allowing for an injection of VARs following a system transient.

Static VAR Compensator (SVC)

The static VAR compensator (SVC) is comprised of a combination of shunt MSCs, TSCs, and thyristor-controlled reactors (TCRs) to control grid parameters by changing the reactive admittance of the SVC. A typical SVC configuration is shown in Fig. 6.8. The maximum level of reactive current changes linearly with the bus voltage, and maximum VAR output varies as the square of the bus voltage. An SVC cannot increase VAR generation during a transient. However, since an SVC is typically implemented in a single-phase, line-to-ground manner, it can provide support during unbalanced faults. Mechanically switched capacitors are preferred for applications consistently requiring capacitive injection, as they have lower losses than TSCs. However, an MSC is limited to 2,000–5,000 switching cycles before the switch must be replaced, limiting the use of the MSC unless the required level of VAR compensation changes slowly [32]. In addition, an MSC has a slower response time than a TSC. The configuration in Fig. 6.8 combines an MSC

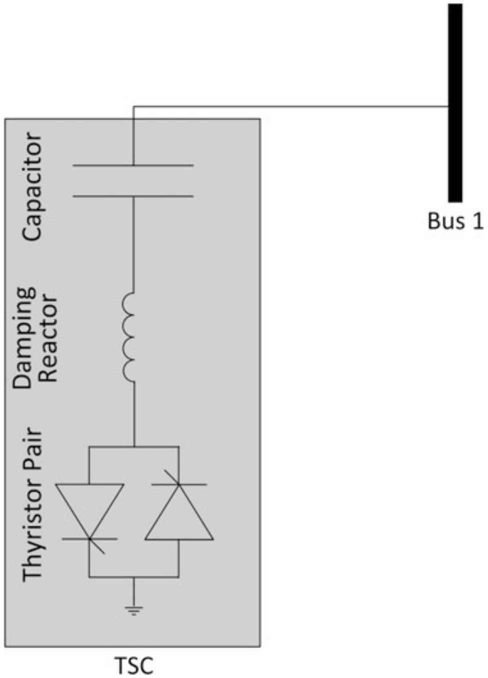


Fig. 6.7 Thyristor-switched capacitor (TSC) connected to bus 1

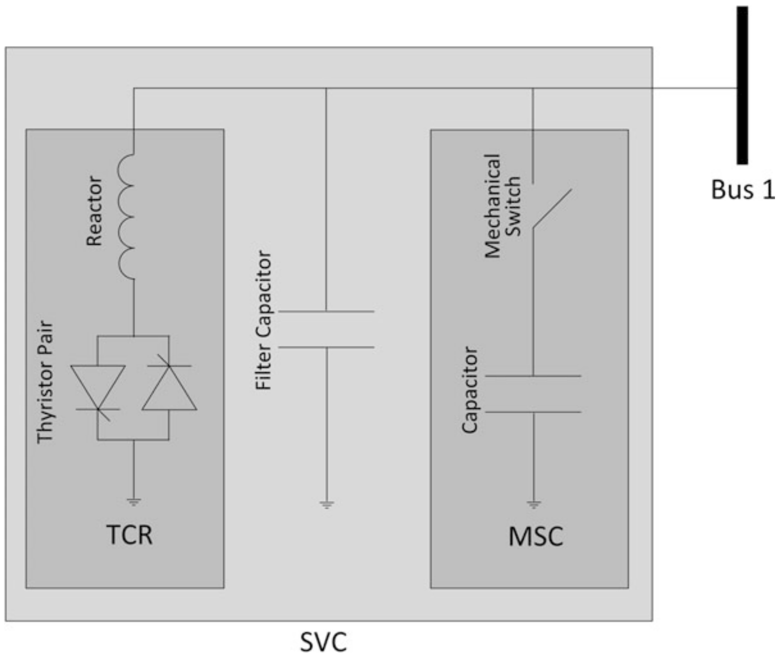


Fig. 6.8 Static VAR compensator (SVC) connected to bus 1

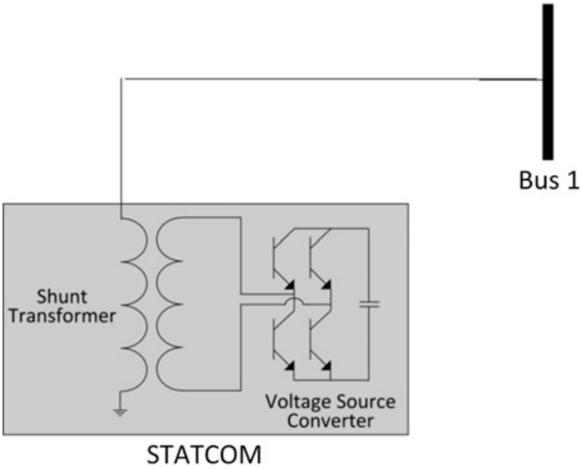


Fig. 6.9 One-line diagram of a static synchronous compensator installed at bus 1

for steady-state capacitive injection with a TCR for transient performance. The TCR generates harmonics which are removed with the shunt filters.

Worldwide, ABB has installed 499 SVCs totaling 73.3 GVAR, 54% of the global total [33]. Of these, 228 units, with a total capacity of 49 GVAR, are for utility customers. The remaining units are for industrial customers. Siemens has installed at least 45 utility SVCs representing almost 10 GVAR of capacity [34]. AMSC, formerly known as American Superconductor, has installed 130 SVCs and STATCOMs, although the breakdown between the two types is unknown [35]. An SVC cost $50/KVAR in the mid-1990s and is expected to cost roughly $80/KVAR now [31].

Static Synchronous Compensator (STATCOM)

A STATCOM uses solid-state gate turnoff devices to mimic the operation of a synchronous condenser, an electrical machine configured to only produce reactive power. The most common type of STATCOM, shown in Fig. 6.9, uses a single three-phase voltage source converter. The STATCOM maximum reactive output current is nearly constant over a wide voltage range, so reactive power output is nearly linear over a wide bus voltage range. Bus voltages are typically depressed during faults and portions of transients, allowing the STATCOM to provide additional VARs during periods with depressed bus voltages compared to an SVC of the same rating. The STATCOM response is an order of magnitude faster than an SVC, and its footprint is 30–40% smaller than an SVC [32].

A STATCOM can also be configured to provide a temporary increase in reactive current during transients. Use of a STATCOM for three-phase fault and transient mitigation allows the use of a lower rating for the STATCOM than the SVC. However, the three-phase converter implementation limits the STATCOM's ability

Table 6.1 Comparison of salient elements of VAR controllers

Technology	Cost ($/kVAR)	Dependency of VARs on bus voltage	Temporary overload capability	Support during unbalanced faults	Response time
MSC	<50	Quadratic	No	Yes	Slow
MSR	<50	Quadratic	No	Yes	Slow
TSC	<50	Quadratic	No	Yes	Medium
SVC	80	Quadratic	No	Yes	Medium
STATCOM – Three phase	150	Linear	Yes	Limited without additional cost	Fast
STATCOM – Single phase	200	Linear	Yes	Yes	Fast
Hybrid	Depends	Depends	Yes	Depends	Depends

to provide VARs during unbalanced faults unless the DC capacitor is significantly overrated relative to steady-state operation. This is a significant disadvantage compared to an SVC since an SVC can typically support unbalanced faults. However, AREVA has implemented a STATCOM able to support unbalanced faults through the use of separate converters for each phase.

A single, three-phase STATCOM was estimated to cost $55/kVAR in the 1990s [31] and $150/kVAR now. A system comprised of three single-phase STATCOMs is estimated to cost $200/kVAR.

Siemens has installed at least 14 STATCOMs [46], and ABB has installed an unspecified number of STATCOMs. AMSC has installed 130 SVCs and STATCOMs, although the breakdown between the two types is unknown [35].

Hybrid VAR Systems

Some installations use an SVC-STATCOM configuration, replacing the TCR of the SVC with a STATCOM. This allows for the use of an MSC, offering lower losses than a TSC, while retaining the quick response of the STATCOM. This also allows for smaller filters since TCRs generate harmonics [32]. The cost and performance characteristics lie between the SVC and STATCOM and depend on the relative rating of the components.

Comparison of Technologies

Table 6.1 provides a comparison of the VAR controllers discussed above.

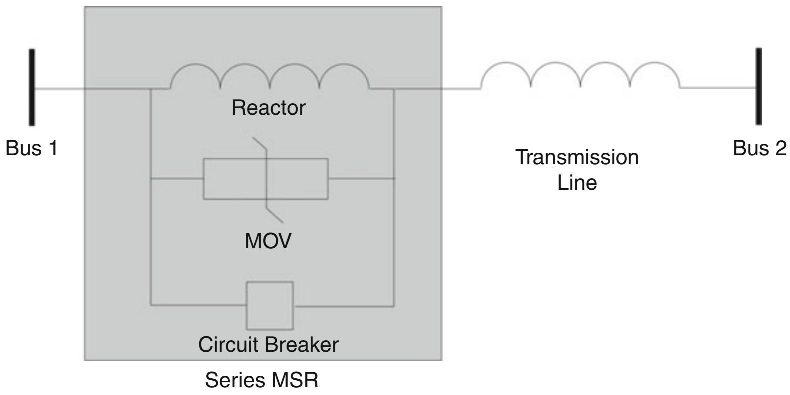


Fig. 6.10 Series mechanically switched reactor (MSR) installed on a transmission line between bus 1 and bus 2

Power Flow Control

Series Mechanically Switched Reactor (series MSR)

A mechanically switched reactor (MSR) can modify line impedance if installed in series with the line as shown in Fig. 6.10 [36, 37]. Appropriately designed, a series MSR can be installed on an overloaded, low-impedance line within a meshed system to push power flow onto less utilized paths, to prevent frequent tripping of the line under system transients and contingencies, and to limit fault currents. It is possible to design the series MSR to be switched out, although that is not frequently done. Further, the speed at which the reactors are switched out is slow, designed mainly for a planned change in system/line impedances, and is not sufficient for the rapid response required to mitigate transients.

A series MSR has a number of advantages and disadvantages relative to other methods to control or increase power flow. It is quicker to install than a new transmission line, with historical projects requiring 6–8 months for construction [38]. In addition, given that the MSR does not require new right of way, it requires significantly less time to plan and permit. However, it imposes an additional footprint requirement somewhere along the line, typically at one of the substations, which may require permitting and add cost. A 230 kV MSR solution in California required an additional 5,000 ft^2 of substation area [37]. To reduce cost, manage mechanical stresses, and avoid core saturation during faults, air core reactors are typically used which leads to increased noise and magnetic fields. The magnetic fields are sufficiently high that care must be taken to mitigate unintentional heating of metallic equipment in the substation and hazards to workers in the substation. Finally, a series MSR is heavy and cannot be supported by the line. This requires that they be ground mounted with the requisite, and costly, isolation between ground and line potential. In the early 2000s, a series MSR cost $11–22/KVAR, although these figures are dated and the current cost is expected to be closer to $50/KVAR [36, 39].

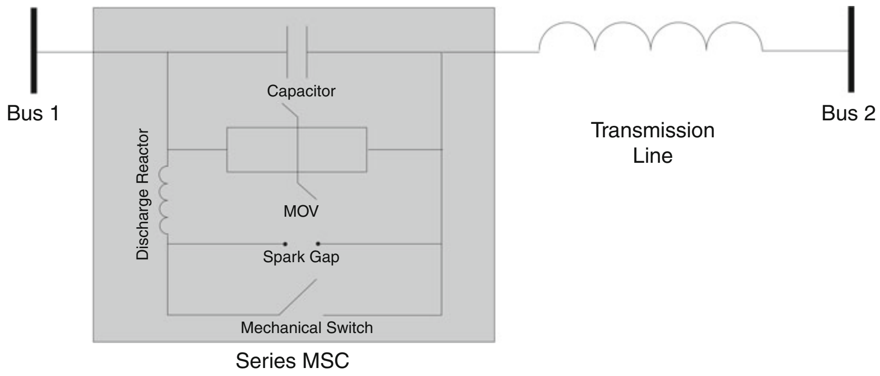


Fig. 6.11 Series mechanically switched capacitor (MSC) installed on a transmission line between bus 1 and bus 2 [45]

Series Mechanically Switched Capacitor (series MSC)

A mechanically switched capacitor (MSC), when inserted in series with a transmission line, can control power flow by lowering the impedance of lightly loaded lines, thereby drawing power away from heavily loaded lines. A typical installation is shown in Fig. 6.11. Like a series MSR, a series MSC is not designed to be switched in or out rapidly and can thus not be used to mitigate transients. Since an MSC is not typically built to endure the high currents of a fault, protection methods are used to bypass the MSC during the fault and reengage it soon thereafter to increase system stability [40]. While early series capacitors were protected from fault currents using a maintenance intensive spark gap, more recent designs utilize an MOV or thyristor protection [41]. Like a series MSR, a series MSC imposes a footprint requirement along the line. As with a series MSR, a series MSC is sufficiently heavy that it cannot be supported by the line and requires an isolated, elevated platform. Finally, an MSC can lead to subsynchronous resonance with the rotating elements of a generator which can cause generator failure and power system instability [42]. This results in siting limitations. The cost for an MSC is $30–50/KVAR [43, 44].

Thyristor-Controlled Series Capacitor (TCSC)

A TCSC, shown in Fig. 6.12, is a series capacitor augmented with an additional shunt path comprised of an inductor and thyristor pair. A TCSC is able to inject a capacitance higher than the nameplate capacitance of the capacitor. However, like the series MSC, this solution is plagued by the need for an isolation platform, which increases cost and requires additional space at the substation. Unlike a series MSC, a TCSC can avert subsynchronous resonance challenges and is fast enough to improve transient stability.

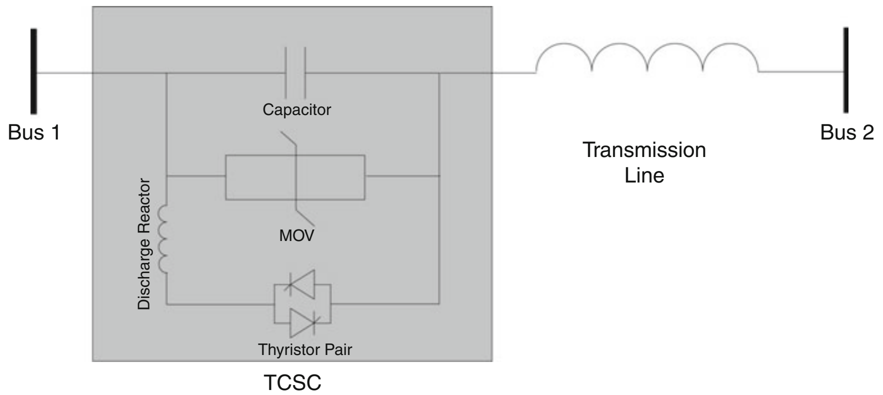


Fig. 6.12 Thyristor-controlled series capacitor (TCSC) installed on a transmission line between bus 1 and bus 2

Multiple manufacturers produce TCSCs. Siemens alone has installed five TCSCs as of late 2009 [46], with the first installation conducted for WAPA in 1992. BPA's 500 kV TCSC project was commissioned in 1993 [47]. Typically, the TCSC solution requires a construction period of 12–18 months. The typical cost for a TCSC is $150/kVAR [48].

Phase-Shifting Transformer (PST)

A phase-shifting transformer (PST), also known as phase angle regulator (PAR), controls power flow between two electrical buses by changing the δ term of Eq. 6.1. Numerous PST topologies exist. The simplest type has a fixed phase angle. In more complicated topologies, mechanical load tap-changers (LTCs) or solid-state switches are used to vary the phase angle. The most common type of PST uses a single core as seen in Fig. 6.13. While previous figures have been one-line diagrams, the PST figures show all three phases due to the cross-coupled nature of the PST. Winding 1 induces a voltage on windings $1'$ and $1''$, which are connected in series with phase A of the transmission line. Since winding 1 is connected between phase B and phase C, the voltages injected into phase A by windings $1'$ and $1''$ are in quadrature to the phase A voltage. The tap changers connected to windings $1'$ and $1''$ allow for the level of the injected quadrature voltage to be varied, regulating the phase shift. A symmetric structure allows a variable quadrature voltage to be injected into phases B and C as well.

This single-core design requires the full line current to pass through the LTCs, exacerbating fault current management and increasing the cost of the LTCs [49]. A more expensive PST relieves some of the drawbacks of a single-core PST through the use of shunt and series transformers, as shown in Fig. 6.14. This version couples a series connected transformer and a delta-connected exciting transformer.

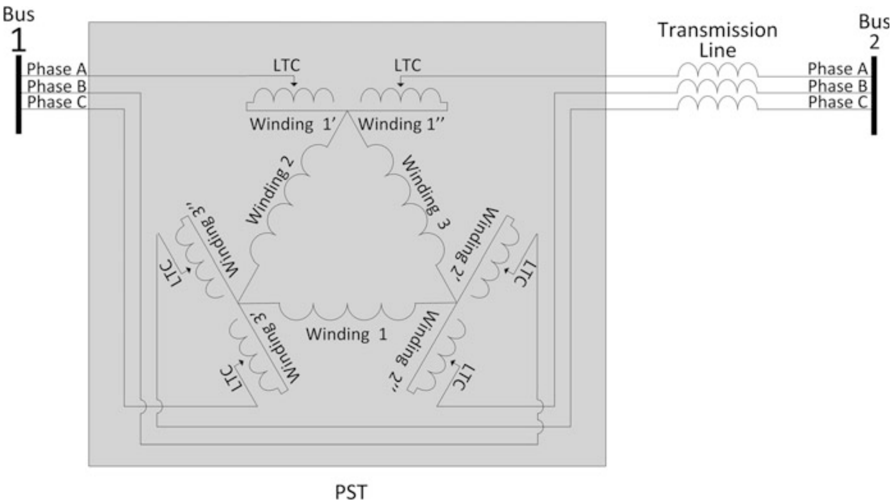


Fig. 6.13 Three-phase diagram of a single-core phase-shifting transformer (PST) installed on a transmission line between bus 1 and bus 2, inspired by [52]

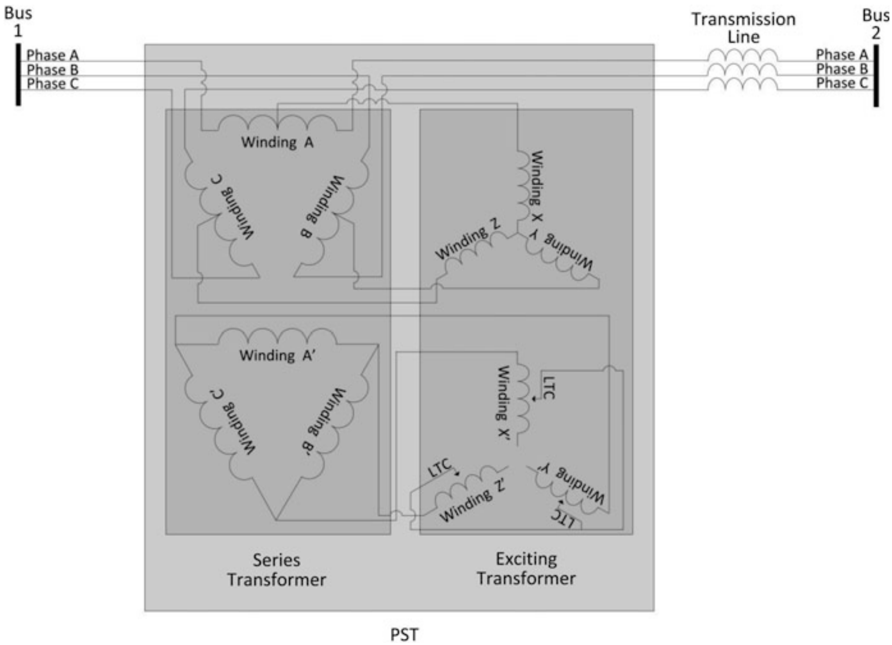


Fig. 6.14 Three-phase diagram of a two-core phase-shifting transformer (PST) installed on a transmission line between bus 1 and bus 2, inspired by [52]

The voltages of windings Y′ and Z′ drive winding A′. The resulting winding A′ voltage is in quadrature to the phase A voltage. Winding A′ impresses a voltage upon phase A of the line, changing the angle. Like the single-core PST, LTCs are used to vary the level of quadrature injection. Another type of PST replaces the mechanical LTCs with pairs of thyristors. Finally, a fifth type of PST uses voltage source converters to synthesize the quadrature injection voltages. Although the PST is frequently used to alter power flows, only the versions using thyristors or voltage source converters are sufficiently fast to mitigate transients. Minimum cost for the single-core PST is estimated to be $150/kVA. Only a fraction of a PST's rating will be controllable, so the actual cost per controlled kVA will be much higher.

PSTs have been identified with ratings up to 500 MW and 230 kV [50]. PSTs have been used in WECC for at least 35 years [51]. Most PSTs deployed in the USA can respond to operator commands or take automatic action to maintain preset power flows in a matter of minutes [50]. The Montana Alberta Tie Limited (MATL), believed to be the first AC merchant project in the USA, is slated to have a PST. In the USA, there are at least 20 PSTs in WECC, at least 36 PSTs in the Eastern Interconnection, and at least 3 in ERCOT.

High-Voltage DC Transmission (HVDC) and Back-to-Back Converter (B2B)

The high-voltage DC transmission system (HVDC) and the back-to-back converter (B2B) transform power from AC to DC and then back to AC. Both can be used to interconnect synchronous or asynchronous networks.

HVDC transports the power in DC form over a distance of up to thousands of miles between the two terminals of the line. HVDC provides full control of the line power. If HVDC is used to connect distant generation to a load pocket, the generation is assigned the same capacity benefits as if it was located in the load pocket [53]. Controllability and capacity benefits have incented the use of HVDC for merchant transmission projects in the USA. In addition, the HVDC line can be configured to limit maximum system fault current levels, an advantage over new AC lines which tend to increase fault current. The most popular type of HVDC system is the bipole, as shown in Fig. 6.15. In the figure, bus 1 and bus 2 are AC, and conversion from DC to AC occurs in the HVDC terminals. Each HVDC terminal includes a converter, a power factor correction system, and a harmonic filter. Power factor correction is required due to the reactive power requirements of the converter. Harmonic filtration is required due to the harmonics generated by the converter. A bipole uses two conductors and does not use the earth return under balanced operation. If one of the poles or conductors is offline, the system can continue to operate at a fraction of rated power. When a pole or conductor is offline, current is returned through the earth. A two-terminal, 3,000 MW bipole HVDC system costs $70/kW for each terminal and $1 M/km [54].

A B2B is an HVDC system with the two terminals directly connected, as shown in Fig. 6.16. The B2B consists of the same components of an HVDC, less the DC transmission line. Like a PST, the B2B allows for the control of the power flow. Unlike

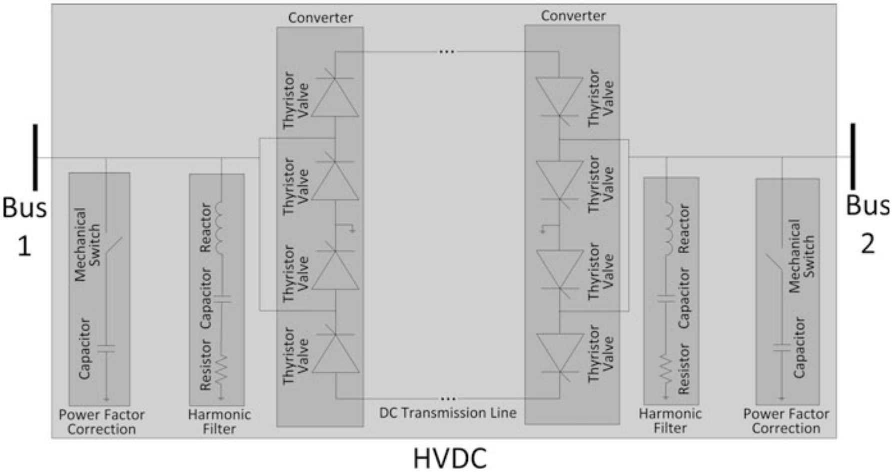


Fig. 6.15 Bipole high-voltage DC transmission system (HVDC) installed between bus 1 and bus 2

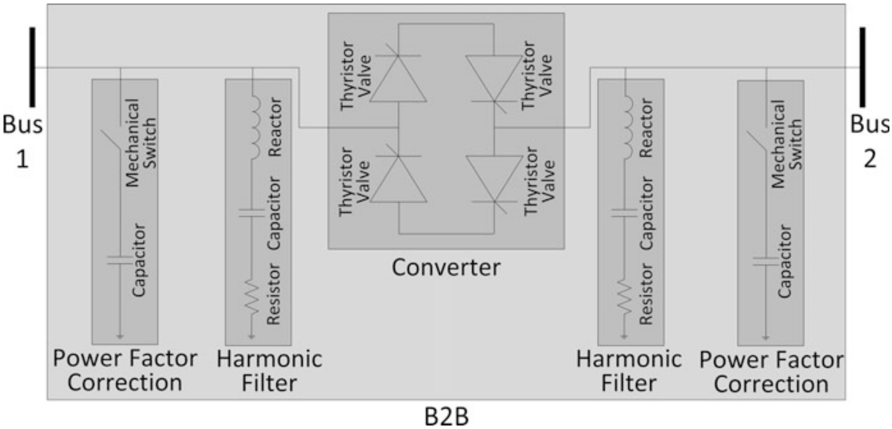


Fig. 6.16 Back-to-back converter (B2B) placed between two AC buses

a PST, it is not limited by the phase shift and fault current limitations of the PST. Also, while a B2B can be used to interconnect asynchronous systems, a PST cannot. However, the B2B cost of $100–300/kW is higher than the PST [55]. Also, the availability of the B2B is around 97%, lower than the 99.9% availability of a transformer [56]. For additional cost, B2B can be used to support black start after a blackout.

HVDC and B2B systems are realized using thyristors or gate turnoff devices. Gate turnoff devices are used for smaller power/voltage levels, but the power/voltage capability of HVDC and B2B systems using gate turnoff devices are increasing. Currently, thyristor-based systems dominate the HVDC and B2B markets.

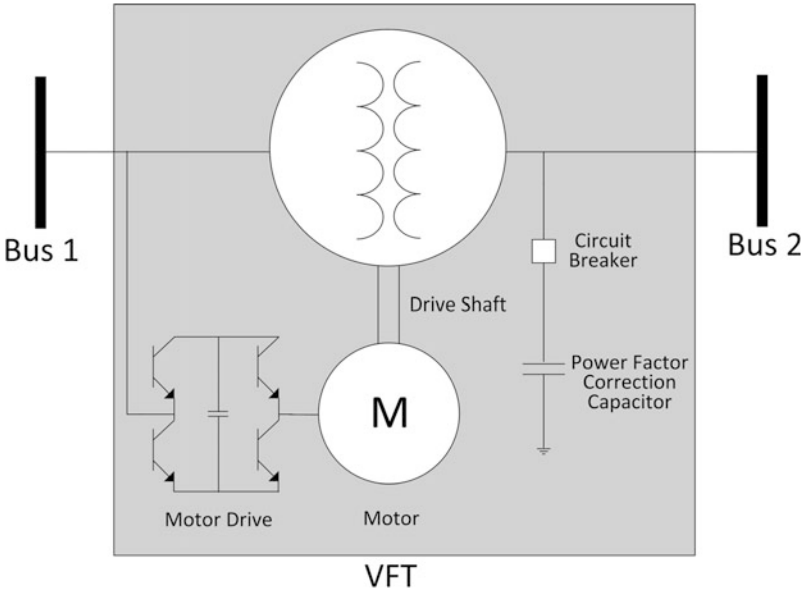


Fig. 6.17 Variable frequency transformer (VFT) connected between two AC buses

In total, nearly 140 GW of HVDC and B2B capacity is installed or planned worldwide. There are numerous B2B systems installed globally. B2Bs are installed at the seams of the three US interconnections as well as interfaces between the US eastern interconnection and the Hydro-Quebec system. ABB alone has completed 30 HVDC projects and 13 B2B projects using thyristors [57] as well as 13 HVDC projects and 1 B2B project using gate turnoff devices. Siemens has installed 13 HVDC projects and 8 B2B projects using thyristor technology [58] as well as one HVDC system with gate turnoff devices [59].

Variable Frequency Transformer™ (VFT)

A variable frequency transformer™ (VFT), as shown in Fig. 6.17, provides functionality similar to a B2B without conversion to DC. The VFT is a large doubly fed induction motor developed by GE for power flow control applications. Power flow from the rotor to stator is varied by changing the torque on the rotor. Torque is applied using a drive motor and variable speed drive. The VFT is able to change power flow from full-rated output in one direction to full-rated output in the other direction in roughly half a second [60]. Each VFT is rated for steady state of 100 MW, but short-term overload power can exceed 150 MW [61]. GE specifies an efficiency of 99% [62] at full power. GE also claims that the area required for a 200 MW VFT station is 47% less than a 200 MW HVDC station [62]. The VFT cost is unknown.

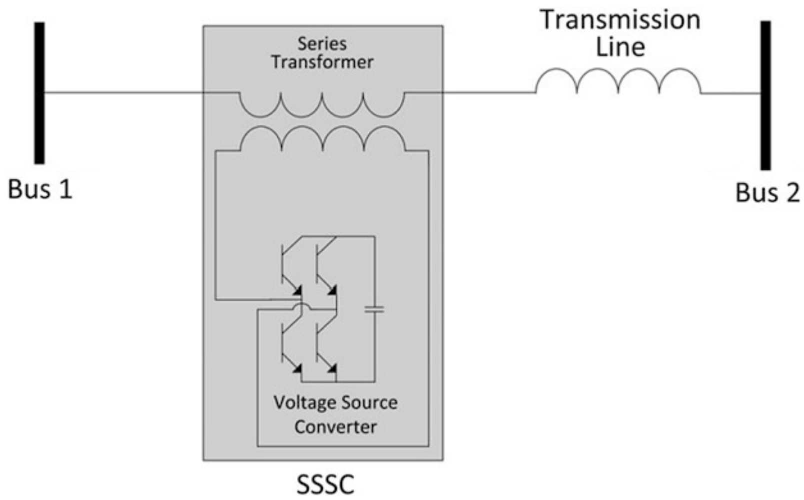


Fig. 6.18 Static synchronous series compensator (SSSC) installed on a transmission line between bus 1 and bus 2

GE has installed 5 VFTs at three locations. The first VFT was used to interconnect the Hydro-Quebec and New York networks. The next three were installed in parallel in Laredo, Texas. The most recent is the Linden VFT, between New York City and New Jersey.

Static Synchronous Series Compensator (SSSC)

The SSSC, shown in Fig. 6.18, improves upon the functionality of a combined series MSR and series MSC through the use of inverters using gate turnoff power electronic devices. Unlike the MSR/MSC combo, the SSSC can provide subcycle response times and actively mitigate transients. Using a voltage source inverter, a voltage is injected into the line in quadrature with the line voltage. Whether this voltage leads or lags the line current determines if the injected VARs are inductive or capacitive. The risk of subsynchronous resonance is mitigated. While no evidence of SSSC installations could be found, it seems the SSSC is designed to be ground mounted and connected to the line via a series transformer. This eliminates the need for the elevated platform used in the MSR, MSC, and TCSC. However, it still requires additional substation space. Also, the series transformer is expensive as it has to be designed to handle high basic insulation levels and high fault currents. The SSSC solution is also plagued by very high costs which are further exacerbated by series protection requirements and customizations. No evidence of global standalone SSSC installations was found. The Marcy convertible static compensator (CSC) can be configured to provide SSSC functionality on two lines simultaneously. Cost is unknown but expected to exceed $200/kVAR [63].

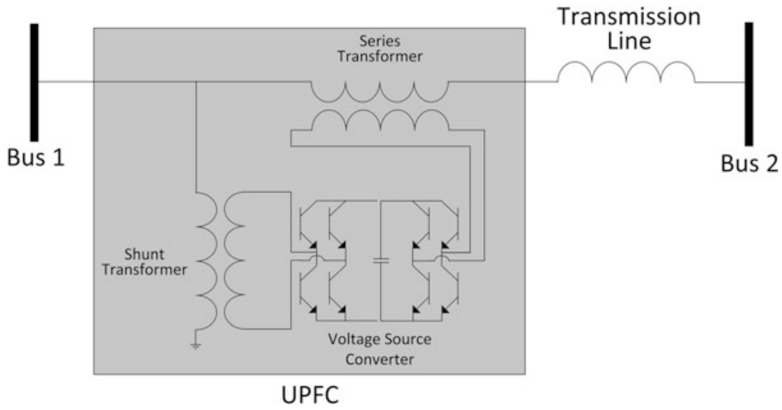


Fig. 6.19 Unified power flow controller (UPFC) with shunt element installed at bus 1 and series element installed between bus 1 and bus 2

Unified Power Flow Controller (UPFC)

A UPFC, as shown in Fig. 6.19, combines a STATCOM and SSSC. The STATCOM and SSSC share a common DC bus, allowing for the injection of real and reactive power into the line. UPFC devices are able to regulate line voltage using shunt VAR control and real and reactive power flow control using series voltage injection. UPFC devices are able to meet the technical performance requirements for power flow control, but are expensive. Cost estimates range from $190/kVA up to $300/kVA [48].

There is at least one dedicated UPFC in the USA, located in Inez, Kentucky. It has a 40 MVA series converter and a 40 MVA shunt converter. There is also a UPFC in Kanjin, Korea. The Marcy convertible static compensator (CSC) can be configured to provide UPFC functionality.

Comparison of Technologies

Table 6.2 provides a brief comparison of the technologies. It is important to recognize that the cost of some technologies is priced in terms of $/kVAR and others in $/kVA. The PST is priced in terms of total throughput power, and the price per KVA controlled will be significantly higher than the value listed. The B2B is also priced in terms of throughput power, but the full-rated power of the B2B is controllable. The UPFC cost is given in terms of dollars per unit control effort.

Table 6.2 Comparison of salient elements of power flow controllers

Technology	Cost	Level of usage	Response time
Series MSR	$50/kVAR	Unknown	Slow, multiple cycles
Series MSC	$30–50/kVAR	Unknown	Slow, multiple cycles
TCSC	$150/kVAR	Minimal	Medium, able to improve transient stability
PST	$150/kVA (single core) Unknown (double core)	Moderate	Depends on design, the most widely deployed version is very slow with a response in seconds to minutes
HVDC	Depends on distance	Moderate	Medium
B2B	$150/kVA (thyristor based)	Moderate	Medium (thyristor) Fast (gate turnoff)
VFT	Unknown	Minimal	Slow, multiple cycles
SSSC	Unknown, likely > $200/kVAr	Assumed to be nonexistent as a stand-alone technology	Fast
UPFC	$190–300/kVA	Minimal	Fast

Emerging Technologies

The following section reviews three emerging technologies which may resolve the limitations of the power flow and VAR controllers described above. All three are thin AC converters (TACC).

Thin AC Converters

To increase the cost effectiveness and reliability of power electronic-based control technologies, the concept of a thin AC converter (TACCs) has been proposed. The TACC augments a passive grid asset, like a power line, shunt capacitor, or transformer, with a fractionally rated converter. In the process, the asset is transformed into a dynamically controllable asset that performs similarly to traditional FACTS devices. In addition, reliability is improved relative to traditional FACTS because the TACC can be bypassed if it fails, leaving the passive asset in service. This is called fail-normal operation. Three TACCs are presented below: smart wires, the controllable network transformer (CNT), and the dynamic capacitor (D-CAP). The technologies have been demonstrated in the lab and are currently being scaled to utility voltage and power levels.

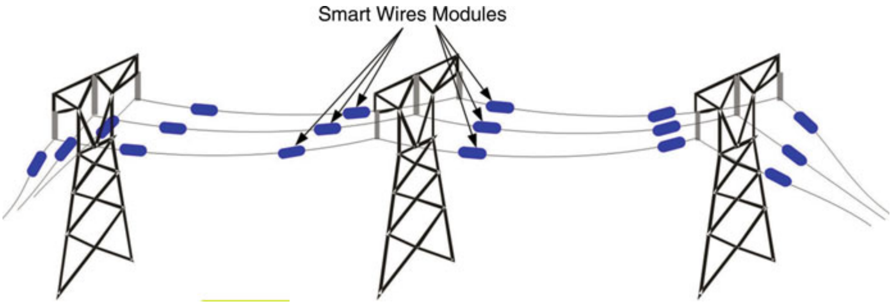


Fig. 6.20 Overview of how smart wires modules will be installed in a transmission line

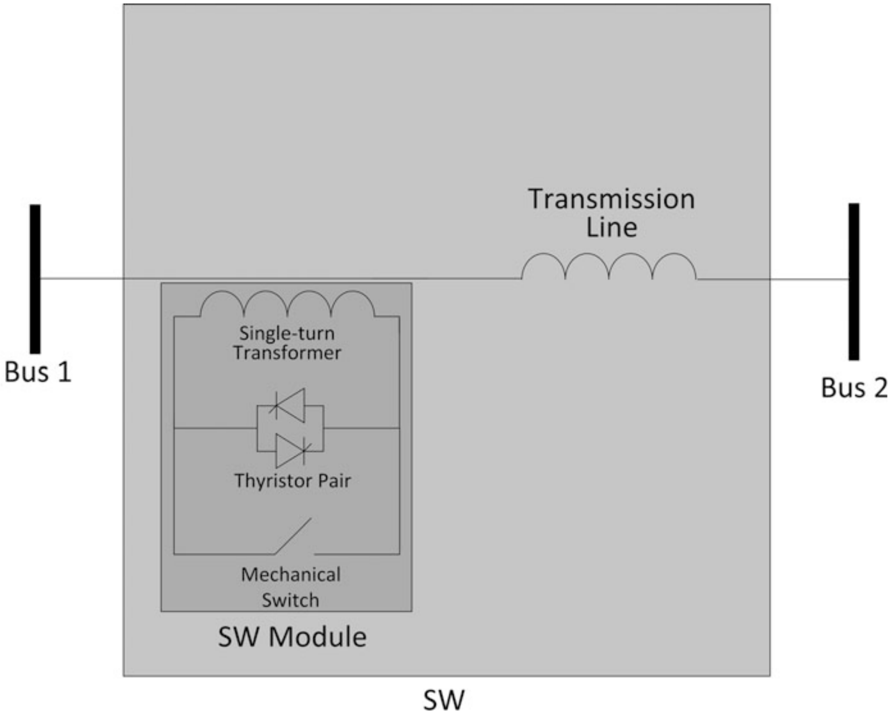


Fig. 6.21 A smart wire (SW) module, installed on a transmission line between bus 1 and bus 2, converts a traditional transmission line into a smart wire (SW)

Smart Wires (SW)

A family of distributed impedance control technologies has been proposed to control power flow. The simplest version of the technology, SW, is comprised of modules hung on the individual conductors of the transmission line as seen in Fig. 6.20. Each module monitors the line current. If line current crosses a preset threshold, the module

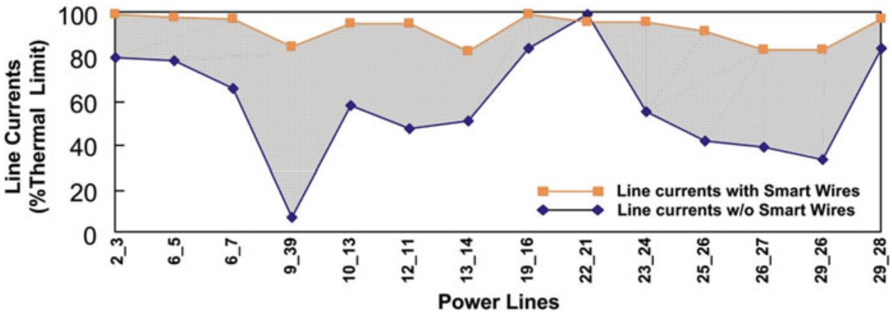


Fig. 6.22 Line utilization of a test system with and without installation of smart wires

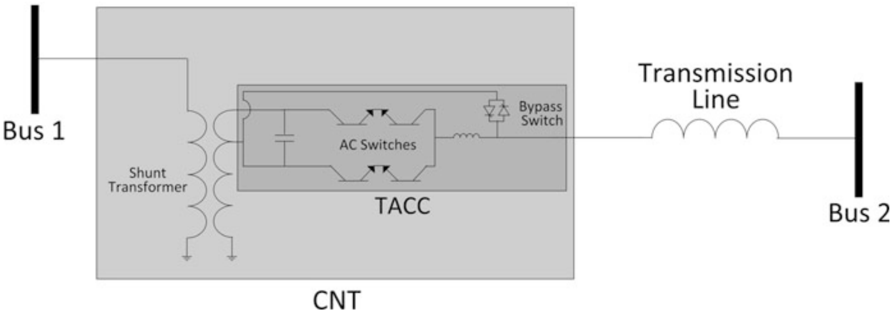


Fig. 6.23 Controllable network transformer (CNT) installed on transmission line between bus 1 and bus 2

autonomously takes action by injecting inductive impedance into the line. Other modules inject impedance at different current levels. The heart of each module, as shown in Fig. 6.21, is a single-turn transformer which when operated with the secondary open injects inductive impedance. The SW modules are self-powered using the line current and do not require communications among the modules or with a central control center. The modules operate at line potential and do not connect to the ground, eliminating the cost of isolation and substation footprint requirements. The target retail price for smart wires is $100/kVAR injected. Figure 6.22 shows the line utilization levels for a system with and without smart wires.

Controllable Network Transformer (CNT)

The CNT provides simultaneous control of bus voltage magnitudes and phase angles by augmenting an existing multitap transformer with a fractionally rated converter, as shown in Fig. 6.23. Since power flow control typically requires small changes to system parameters, the converter can be fractionally rated with respect to the transformer and achieve meaningful, independent control of real and reactive power through the transformer. Any real and reactive power combination within the control

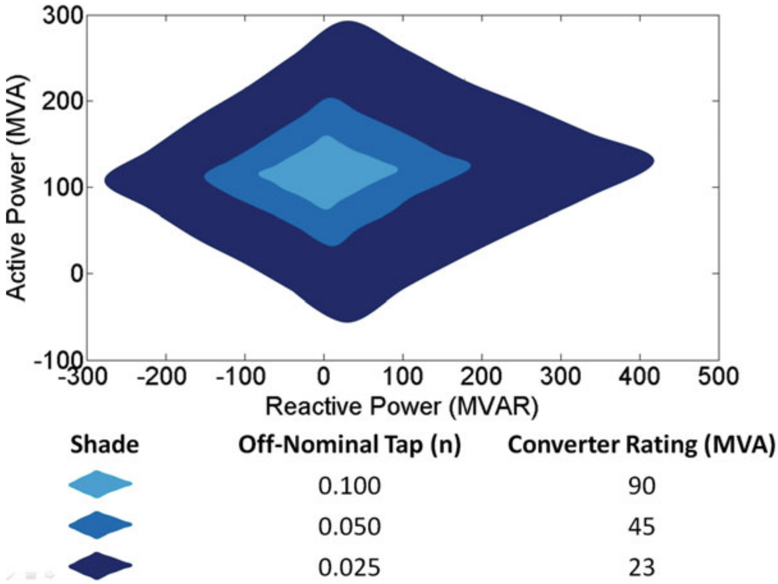


Fig. 6.24 CNT control range as a function of the transformer tap range. 0.10 means up to 10% of the transformer voltage is connected to the converter

range of the CNT, shown in Fig. 6.24, is possible. The CNT provides the functionality of both a PST and an LTC transformer. An LTC transformer is often used to adjust output voltage or VARs, but it cannot adjust phase angle. The CNT response is significantly faster than the typical LTC or PST, allowing it to help mitigate transients.

Dynamic Capacitor (D-CAP)

The D-CAP, shown in Fig. 6.25, combines a traditional shunt capacitor with a pair of AC switches and small filtering elements. The switches operate with a duty cycle to effectively change the total capacitance seen by at the bus. Like an SVC, the D-CAP is able to dynamically vary the amount of capacitance. However, unlike an SVC, the D-CAP can react within a fraction of a cycle. The D-CAP configured in a "boost" configuration as shown, also can maintain the VARs delivered to the line, even as the voltage sags under a grid fault. An SVC is unable to deliver this level of grid voltage support. In addition, the D-CAP is able to remove unwanted harmonics caused by other loads connected to the power system, as seen in Fig. 6.26. The ability to remove harmonics is in sharp contrast to the SVC, which creates harmonics. Costly and space-intensive filters must be used to remove the harmonic content generated by the SVC.

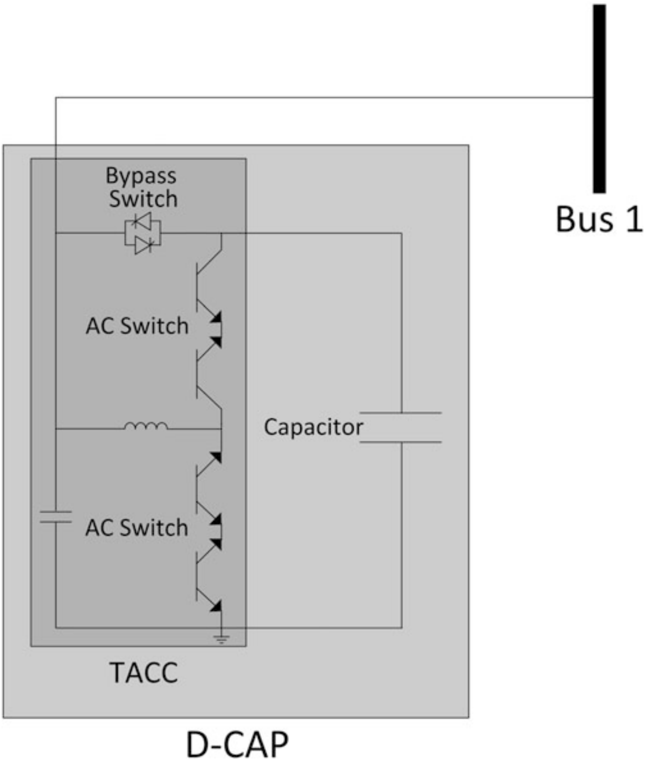


Fig. 6.25 Dynamic capacitor (D-CAP) connected to bus 1

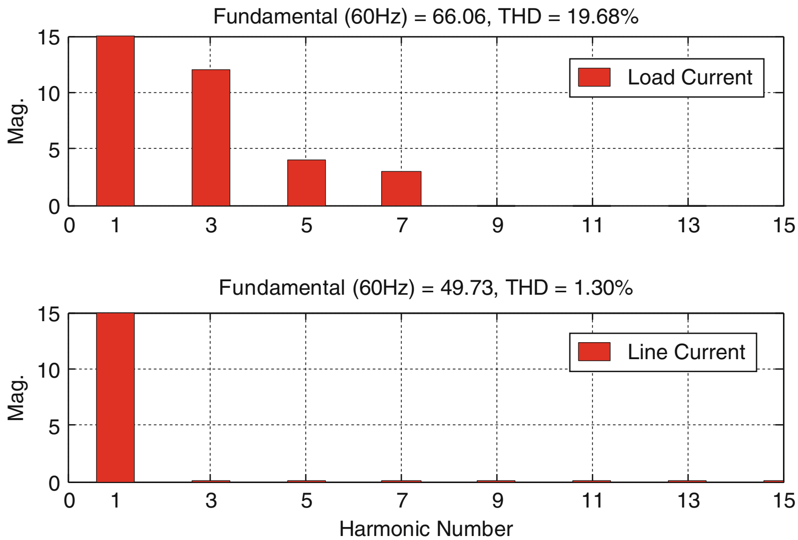


Fig. 6.26 Plot of fundamental and harmonic magnitudes in load current (*top*) and line current (*bottom*) with D-CAP installed. Without the D-CAP, the load current harmonics would appear in the line current

Power Flow Control as an Enabler for Improved Energy Markets

Due to the lack of power flow control, contentious cost allocation methods have been developed to ensure transmission owners recover their costs. Because transmission owners have little incentive to invest in new lines, RTOs/ISOs mandate the construction of transmission lines deemed necessary to relieve pending reliability problems or severe economic congestion. The thresholds to judge proposed transmission projects to relieve economic congestion are conservative, resulting in less investment than would occur if the power flow was more controllable. This leads to higher cost of energy for consumers.

Every merchant transmission project built in the USA thus far has included some form of power flow control. Widespread power flow control would allow the types of market transactions seen in the petroleum and natural gas pipeline industries. Examples include bidding, bilateral transactions, and bulletin boards to match transmission owners with prospective transmission users. With control, a transmission user urgently needing to use a line to deliver to market, such as a wind generator which cannot cheaply store its energy, can pay a premium during windy periods to outbid other would-be users of the line. In this case, a user willing to defer generation, such as coal plant able to store energy by leaving coal unburned, would benefit from lower transmission costs when the renewable resource is unavailable. In contrast, under current transmission operation rules, transmission users of all types are often backed down pro rata based on the amount of long-term transmission capacity reserved. This leads to economic inefficiencies and higher costs.

The ability to inexpensively control power flows along specific paths can lead to significant benefits at the system and market level. The need for new transmission line build to accommodate renewable portfolio standards can be dramatically reduced. Loop flows, that reduce the capacity of the line available for use by the line owner, can be controlled. Improved interarea support during contingencies can improve the reliability and stability of the network. Costs associated with grid build-out and operation can be allocated more fairly. Owners of generation assets can sell energy to interested customers, finding uncongested pathways for power delivery. Overall, the smart and controllable grid is a critical element in realizing a greener and more economically efficient energy market.

Conclusions and Future Directions

This entry has discussed the emerging challenges which will place additional stress on the transmission system and some of the potential methods to relieve these stresses. A number of methods already exist to provide VAR control and power flow control. All of these methods are expensive and have disadvantages, which have limited their adoption. Emerging technologies that use fractionally rated control elements, and are inherently more distributed in nature, may overcome the significant disadvantages, allowing widespread adoption of VAR control and power flow control. These capabilities could transform the operation of the transmission system, enabling the delivery of low cost and renewable energy, and allowing efficient operation of a competitive energy market.

Bibliography

1. IEA (2008) World energy outlook 2008. http://www.iea.org/textbase/nppdf/free/2008/weo2008.pdf. Accessed 30 Mar 2011
2. EIA (2010) Table 8: electricity supply, disposition, prices, and emissions. Annual energy outlook 2011. http://www.eia.doe.gov/forecasts/aeo/excel/aeotab_8.xls. Accessed 16 Mar 2011
3. EIA (2010) Table 46: transportation sector energy use by fuel type within mode. Annual energy outlook 2011. http://www.eia.gov/oiaf/aeo/supplement/suptab_46.xls. Accessed 24 Apr 2011
4. Sovacool B, Sovacool K (2009) Identifying future electricity–water tradeoffs in the United States. Energy Policy 37(7):2763–2773
5. Wang F, Yin H, Li S (2010) China's renewable energy policy: commitments and challenges. Energy Policy 38(4):1872–1878
6. DOE (2011) RPS data spreadsheet. http://www.dsireusa.org/rpsdata/RPSspread010211.xlsx. Accessed 30 Mar 2011
7. NYSERDA (2004) The effects of integrating wind power on transmission system planning, reliability, and operations: report on phase I
8. Xcel Energy, Minnesota Department of Commerce (2004) Wind integration study – Final report
9. NYSERDA (2005) The effects of integrating wind power on transmission system planning, reliability, and operations, report on phase 2: system performance evaluation
10. Minnesota Public Utilities Commission (2006) Final report – 2006 Minnesota Wind Integration Study, vol I
11. CEC (2007) Intermittency analysis project: final report, CEC-500-2007-081
12. Arizona Public Service Company (2007) Final report: Arizona Public Service wind integration cost impact study
13. CA ISO (2007) Integration of renewable resources. http://www.caiso.com/1ca5/1ca5a7a026270.pdf. Accessed 27 Oct 2010
14. ERCOT (2008) Analysis of wind generation impact on ERCOT Ancillary Services requirements – final report
15. Xcel Energy (2008) Final report: wind integration study for Public Service of Colorado
16. SPP (2010) SPP WITF wind integration study
17. NREL (2010) Eastern wind integration and transmission study. Subcontract report NREL/SR-550-47078
18. NREL (2010) Nebraska statewide wind integration study, Apr 2008–Jan 2010. NREL/SR-550-47519
19. NREL (2010) Western wind and solar integration study. Subcontract No. AAM-8-77557-01
20. NYISO (2010) Growing wind: final report of the NYISO 2010 wind generation study
21. NREL (2010) Oahu wind integration and transmission study: summary report. TP-5500-48632
22. GE Energy (2010) Final report: new england wind integration study – executive summary. Prepared for ISO New England

23. BP (2010) BP statistical review of world energy. http://www.bp.com/liveassets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statistical_energy_review_2008/STAGING/local_assets/2010_downloads/Statistical_Review_of_World_Energy_2010.xls. Accessed 24 Apr 2011
24. Electrification Coalition (2009) Electrification roadmap, Revolutionizing Transportation and Achieving Energy Security. http://www.electrificationcoalition.org/reports/EC-Roadmap-screen.pdf. Accessed 7 Mar 2011
25. Allegro Energy (2001) How pipelines make the oil market work their networks, operation and regulation – a memorandum prepared for the association of oil pipe lines and the American Petroleum Institute's Pipeline Committee. http://www.pipeline101.com/reports/Notes.pdf. Accessed 25 May 2009
26. Hull B (2005) Oil pipeline markets and operations. J Transp Res Forum 44(2):111–125
27. Brown S, Yücel M (2008) Deliverability and regional pricing in U.S. Natural Gas Markets. Energy Econ 30(5):2441–2453
28. Cremer H, Gasmi F, Laffont J (2003) Access to pipelines in competitive gas markets. J Regul Econ 24(1):5–33
29. Silvestre B, Hall J, Matos S, Figueira L (2010) Privatization of electricity distribution in the Northeast of Brazil: the good, the bad, the ugly or the naïve? Energy Policy 38(11):7001–7013
30. Balijepalli V, Khaparde S, Gupta R (2009) Towards Indian smart grids. In: IEEE region 10 TENCON, pp 1–7
31. ORNL (1997) Ancillary service details: voltage control. ORNL/CON-453
32. Hingorani N, Gyugyi L (1999) Understanding FACTS: concepts and technology of flexible AC transmission systems. IEEE Press, New York
33. ABB (2010) ABB SVC and SVC light projects worldwide. http://search-ext.abb.com/library/Download.aspx?DocumentID=SVC_U%20Ref&LanguageCode=en&DocumentPartID=&Action=Launch. Accessed 1 Apr 2011
34. Siemens (2010) FACTS – flexible AC transmission systems: static VAR compensators. http://www.energy.siemens.com/hq/pool/hq/power-transmission/FACTS/FACTS_References_SVC.pdf. Accessed 1 Apr 2011
35. American Superconductor (2010) AMSC™ SVC static VAR compensator. http://www.amsc.com/pdf/PESSVC_BRO_0810_lores.pdf. Accessed 2 Apr 2011
36. Wolf G, Skliutas J et al. (2003) Alternative method of power flow control: using air core series reactors. In: Proceedings of the IEEE Power Engineering Society General Meeting, Vol. 2
37. Bonheimer D, Lim E, Dudley R, Castanheira A (1991) A modern alternative for power flow control. In: Proceedings of the IEEE Power Engineering Society transmission and distribution conference, Dallas, 22–27 Sep 1991, pp 586–591
38. Papp K, Christiner G, Popelka H, Schwan M (2004) High voltage series reactors for load flow control. e&i Elektrotechnik und Informationstechnik 121:455–460
39. Surapongpun L, Phuyodying P, Pimjaipong W (2002) New alternative of power control for transmission line investment in Thailand. In: Proceedings of the IEEE PES transmission and distribution conference and exhibition, Yokohama, pp 1596–1600
40. Courts A, Hingorani N, Stemler G (1978) A new series capacitor protection scheme using nonlinear resistors. IEEE Trans Power Appar Syst 97:1042–1052
41. Bhargava B, Haas R (2002) Thyristor protected series capacitors project at Southern California Edison Co. IEEE Power Eng Soc Summer Meet 1:241–246
42. Elfayoumy M, Moran C (2003) A comprehensive approach for subsynchronous resonance screening analysis using frequency scanning technique. In: IEEE power tech conference proceedings, Bologna
43. Agrawal B (2009) Reactors, capacitors, SVC, PSS: long term transmission planning seminar. Arizona Public Service Co, Long term transmission planning seminar
44. Acharya N (2004) Facts and figures about FACTS. Presented at: AIT training workshop on FACTS application, Asian Institute of Technology, December 16, 2004

45. Altuve H, Mooney J, Alexander G (2009) Advances in series-compensated line protection. In: Proceedings of the 62nd Annual Conference for Protective Relay Engineers, pp 263–275
46. Retzmann D (2009) Tutorial on VSC in transmission systems HVDC & FACTS. http://www.ptd.siemens.de/Siemens2_VS_Application_Prospects_V1.pdf. Accessed 1 Apr 2011
47. Urbanek J, Piwko R, Larsen E, Damnsky B, Furumasu B, Mittlestadt W, Eden J (1993) Thyristor controlled series compensation prototype installation at the slatt 500 kV substation. IEEE Trans Power Deliv 8(3):1460–1469
48. Cai L, Erlich I, Stamtsis G (2004) Optimal choice and allocation of FACTS devices in deregulated electricity market using genetic algorithms. In: Proceedings of the 2004 IEEE PES Power Systems Conference and Exposition, pp 201–207
49. IEEE (2010) IEEE draft guide for the application, specification and testing of phase shifting transformers. IEEE PC57.135, Draft revision 8, Nov 2010, pp 1–53
50. Bladow J, Montoya A (1991) Experiences with parallel EHV phase shifting transformers. IEEE Trans Power Deliv 6(3):1096–1100
51. WECC (2009) Unscheduled Flow (USF) FAQ. http://www.wecc.biz/committees/Standing-Committees/OC/UFAS/Shared%20Documents/USF%20FAQ.doc. Accessed 20 Mar 2011
52. IEEE (2010) IEEE draft guide for the application, specification and testing of phase shifting transformers. IEEE PC57.135_D8, pp 1–53
53. O'Neill R (2010) Merchant transmission: a new approach to transmission expansion. In: Proceedings of the 2010 IEEE Power and Energy Society general meeting, pp 1–5
54. Bahrman M, Johnson B (2007) The ABCs of HVDC transmission technologies. IEEE Power Energ Mag 5(2):32–44
55. Hingorani N (1996) High-voltage DC transmission: a power electronics workhorse. IEEE Spectr 33(4):63–72
56. ABB (2011) HVDC classic reliability and availability. http://www.abb.com/industries/ap/db0003db004333/eb8b4075fb412
52ec12574aa00409424.aspx. Accessed 5 May 2011
57. ABB (2010) HVDC classic – reference list. http://www05.abb.com/global/scot/scot221.nsf/veritydisplay/a0f3c70bc17b846fc
12577a8004da670/$file/pow-0013%20rev10%20lr.pdf. Accessed 1 Apr 2011
58. Siemens (2011) References. http://www.energy.siemens.com/hq/en/power-transmission/hvdc/hvdc-classic/references.htm. Accessed 1 Apr 2011
59. Siemens (2011) HVDC plus (VSC Technology). http://www.energy.siemens.com/hq/en/power-transmission/hvdc/hvdc-plus/#content=References. Accessed 1 Apr 2011
60. Larsen E, Piwko R, McLaren D, McNabb D, Granger M, Dusseault M, Rollin L, Primeau J (2004) Variable frequency transformer – a new alternative for asynchronous power transfer. http://www.gepower.com/prod_serv/products/transformers_vft/en/downloads/overview_vftmarketing.pdf. Accessed 6 Apr 2011
61. Miller N, Clark K, Piwko R, Larsen E (2006) Variable frequency transformer: applications for secure inter-regional power exchange. Presented at PowerGen Middle East 2006. http://www.gepower.com/prod_serv/products/transformers_vft/en/ downloads/vftfor_pgmev9.pdf. Accessed 4 Apr 2011
62. GE (2004) Variable frequency transformer™: fact sheet. http://www.gepower.com/prod_serv/products/transformers_vft/en/ downloads/vft_factsheet.pdf. Accessed 1 Apr 2011
63. Song W, Bhattacharya S, Huang A (2008) Fault-tolerant transformerless power flow controller based on ETO light converter. In: Proceedings of the 2008 IEEE Industry Applications Society annual meeting, pp 1–5
64. Moghe R, Kreikebaum F, Hernandez J, Kandula R, Divan D (2011) Mitigating distribution transformer lifetime degradation caused by grid-enabled vehicle (GEV) charging. In: Proceedings of the IEEE Energy Conversion Congress & Expo, Phoenix, 17–22 Sep 2011, pp 835–842

Chapter 7
Underground Cable Systems

Yamille Del Valle, Nigel Hampton, Josh Perkel, and Caryn Riley

Glossary

Breakdown	Permanent failure through insulation.
Cable system	Cable with installed accessories.
CCV	Catenary continuous vulcanization extrusion line for extruded dielectrics.
Cross-linked polyethylene (XLPE)	A thermoset unfilled polymer used as electrical insulation in cables.
Diagnostic test	A field test made during the operating life of a cable system. It is intended to determine the presence, likelihood of future failure and, for some tests, locate degraded regions that may cause future cable and accessory failure.
Dielectric loss	An assessment of the electric energy lost per cycle. A poorly performing cable system tends to lose more energy per AC cycle. Measurements can be made for selected voltages or over a period of time at a fixed voltage. The stability of the loss, the variation with voltage and absolute loss are used to estimate the condition. Data can be derived from time-based (if sufficient time is taken) or frequency-based test methods.
Electrical trees	Permanent dendritic growths, consisting of nonsolid or carbonized micro-channels, that can occur at stress enhancements such as protrusions, contaminants, voids,

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3

Y.D. Valle (✉) • N. Hampton • J. Perkel • C. Riley
National Electric Energy Test Research and Application Centre (NEETRAC),
NEETRAC Campus, 5351 Kennedy Road, Forest Park, GA 30297, USA
e-mail: nigel.hampton@neetrac.gatech.edu

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*, DOI 10.1007/978-1-4614-5830-2_7,

	or water trees subjected to electrical stress. The insulation is damaged irreversibly at the site of an electrical tree.
Ethylene propylene rubber (EPR)	A type of thermoset-filled polymer used as electrical insulation in cables and accessories. There are several different formulations of EPR and they have different characteristics. For purposes here, the term also encompasses ethylene propylene diene monomer rubber (EPDM).
Extra high voltage (EHV)	Cable systems within the voltage range 161–500 kV, though more often between 220 kV and 345 kV. Also referred to as transmission class, though usually has higher design stress levels than HV.
Extruded dielectrics	Insulation such as EPR, HMWPE, PE, WTRXLPE, XLPE, etc., applied using an extrusion process.
Filled insulation	Extruded insulations where a filler (carbon black or clay) has been incorporated to modify the inherent properties of the base polymer. This class includes all types of EPR, Vulkene, etc.
High pressure fluid filled (pipe type or HPOF)	paper insulated and installed in trefoil in steel pressure pipes and impregnated with high-pressure nondegradable fluid which is maintained at high pressures by pumping plants – common in USA at HV & EHV.
High voltage (HV)	Cable systems within the voltage range from 46–161 kV, though more often between 66 kV and 138 kV. Also referred to as transmission class, though usually has lower design stress levels than EHV.
Jacket	An extruded outer polymeric covering for cables designed to protect the cable core and the metallic shielding (wires, tapes, or foils).
Joint	A device to join two or more sections of power cable together. A joint includes a connector to secure the cable conductor and a stress controlling/insulating body to manage the electrical stress.
Laminated dielectrics	Insulation formed in layers typically from tapes of either cellulose paper or polypropylene or a combination of the two. Examples are the PILC (paper-insulated lead-covered) and MIND (mass-impregnated non-draining) cable designs.
Mass impregnated non-draining Cable (MIND)	A cable design using paper insulation impregnated with a thick compound such that the compound does not leak out when the lead is breached.
Maximum electrical stress	The highest level of stress also corresponds to the highest probability of instantaneous failure or, equivalently, the highest rate of electrical aging.
MDCV	Mitsubishi Dainichi continuous vulcanization, often called long land die, extrusion line for XLPE, typically for HV & EHV.

Mean or average electrical stress	This is most important if the most serious defects are uniformly located throughout the bulk of the insulation.
Medium voltage (MV)	Cable systems within the voltage range from 6 kV to 46 kV, though more frequently between 15 kV and 35 kV. Also referred to as distribution class.
Metallic shield	A concentric neutral surrounding the cable core. The shield provides (to some degree) mechanical protection, a current return path, and, in some cases, a hermetic seal (essential for impregnated cables).
Minimum electrical stress	This is most important if cable system reliability is determined by the performance of accessories or if the electrical design or installation method of accessories degrades cable performance.
Paper insulated lead covered (PILC)	A cable design using paper insulation impregnated with a fluid and encased in lead to prevent the fluid from leaking out of the insulation.
Partial discharge	A low voltage (mV or μV) signal resulting from the breakdown of gas enclosed in a dielectric cavity. The signals travel down the cable system and may be detected at the end, thereby enabling location.
PE-based	Extruded insulations that do not have an incorporated filler (carbon black or clay). This class includes all types of HMWPE, PE, WTRXLPE, XLPE, etc.
Polyethylene (PE)	A polymer used as electrical insulation in cables.
Power frequency	A substantially sinusoidal waveform of constant amplitude with an alternating frequency in the range of 49–61 Hz.
Self-contained fluid filled (FF or LPOF or PILC)	Paper or paper polypropylene laminated (PPL) insulated with individual metal sheaths and impregnated with a dielectric fluid. Where used these are common in land cable applications. This type of cable is one of the first to be installed in the 1890s.
Shielded cable	A cable in which an insulated conductor is encapsulated in a conducting "cylinder" that is connected to ground.
Space charge	Quasi-permanent injected charge that is trapped within the insulation of a cable system. This charge is sufficient to modify the applied AC and impulse voltage stresses.
Splice	A joint.
Tan δ (TD)	The tangent of the phase angle between the voltage waveform and the resulting current waveform.
Termination	A device that manages the electric stress at the end of a cable circuit, while sealing the cable from the external environment and providing a means to access the cable

	conductor. Devices referred to as elbows or potheads are types of terminations.
VCV	Vertical continuous vulcanization extrusion line for XLPE, typically for HV & EHV
Water tree retardant cross-linked polyethylene (WTRXLPE)	A thermoset polymer used as electrical insulation in cables that is designed to retard water tree growth.
Water trees	Dendritic pattern of electro-oxidation that can occur at stress enhancements such as protrusions, contaminants, or voids in polymeric materials subjected to electrical stress and moisture. Within the water tree the insulation is degraded due to chemical modification in the presence of moisture.

Definition of the Subject

Underground cables have been used from the earliest time as integral parts of the power distribution and transmission system. Compared to their overhead analogues, they have been long regarded as the most critical of components due in part to their high total installed cost, their unique ampacity requirements, and the complexity of their installation. Thus, even from the very first technical papers, the sustainability, through reliability and longevity, has been of paramount importance. This contribution addresses the focus on sustainability today while maintaining a linkage to the lessons that have been already learned.

Introduction

Almost all electric power utilities distribute a portion of the electric energy they sell via underground cable systems. Collectively, these systems form a vast, interlinked, and valuable infrastructure. Estimates for the USA indicate that underground cables represent 15–20% of installed distribution system capacity. This percentage is much closer to 50% in Europe. These cable systems consist of many thousands of miles of cable and hundreds of thousands of accessories installed under city streets, suburban developments, and the countryside. Utilities have a long history of using underground system with some of these cable systems installed as early as the 1890s. Very large quantities of cable circuits were installed in the 1950s–1980s. Today, the size of that infrastructure continues to increase rapidly as the majority of

Table 7.1 Factors encouraging and discouraging the installation of underground cable systems

Encouraging installation of underground cable systems	Discouraging installation of underground cable systems
Public perception of risk	Capital cost – higher for cable systems
Reliability (frequency of outages) – frequency is lower for underground cable systems	Return to service after failure (repair time) – longer repair time
Total operating cost – lower electrical losses & lower repair and maintenance costs	Need for reactive compensation on long lengths AC systems
Public perception of visual impact – lower impact	

newly installed electric distribution lines are placed underground. There are a number of drivers and brakes that control this process and they are shown in Table 7.1.

Cable systems are designed to have a long life with high reliability. However, the useful life is not infinite. These systems age and ultimately reach the end of their reliable service lives. Estimates set the design life of underground cable systems to be in the range of 30–40 years. Today, a large portion of this cable system infrastructure is reaching the end of its design life, and there is evidence that some of this infrastructure is reaching the end of its reliable service life. This is a result of natural aging phenomena as well as the fact that the immature technology used in some early cable systems is decidedly inferior compared to technologies used today. Increasing failure rates of these older systems are now adversely impacting system reliability, and it is readily apparent that action is necessary to manage the consequences of this trend.

Cable System Structure

The name "cables" is given to long current-carrying devices that carry their own insulation and present an earthed outer surface [1]. In this context, overhead lines, for example, are not considered as cables. Power cables have a coaxial structure: Essentially, they comprise a central current-carrying conductor at line voltage, an insulation surrounding the conductor, and an outer conductor at earth potential. AC cables are generally installed as a 3-phase system, and hence, the outer conductor should only carry fault and loss currents. In practice, a more sophisticated construction is adopted. The interfaces between the metal conductors and the insulation (laminated or polymeric) would tend to include contaminants, protrusions, and voids, features that would lead to electrical stress enhancement, accelerated aging, and premature failure [2, 3]. To overcome this, a "semicon" layer, a conductive paper or polymeric composite, is placed at both interfaces. The inner semicon, the insulation, and the outer semicon ensure the interfaces are smooth and contaminant-free. Surrounding this cable are layers to protect the cable during installation/operation and carry the loss/fault currents. These layers also serve to keep out

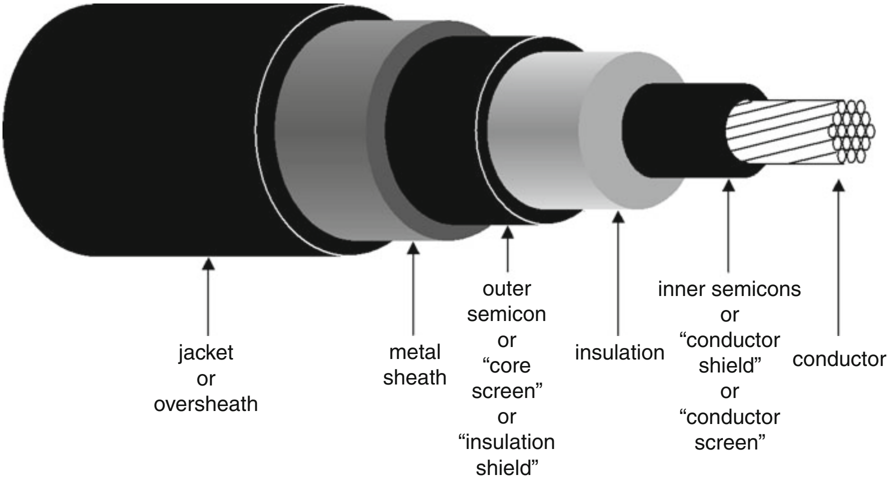


Fig. 7.1 Cut-away section of a typical power cable

Table 7.2 Voltage classes for AC cable systems in selected regions

	MV	HV	EHV
Asia	6.6, 10, 15, 22, 33	66, 90, 110, 132, 154, 161	187, 220, 275, 345, 400, 500, 525
Europe	11, 20, 33	63, 66, 90, 110, 132, 145, 150	220, 275, 380, 400
North America	15, 25, 35, 46	69, 115, 138	220, 230, 345, 500
	Distribution	Transmission	
Nordic	20	90, 132, 145	220, 400

water, which may lead to water treeing in polymer insulations or elevated losses in laminated insulations. A schematic diagram of a power cable is shown in Fig. 7.1.

MV, HV, and EHV Cable Systems

Cable systems that are used for distribution and transmission purposes are generally categorized according to the voltage rating:

- Medium voltage (MV): 6–36 kV
- High voltage (HV): 36–161 kV
- Extra high voltage (EHV): 161–500 kV (or more)

There is no international consistency on the distinction between "distribution" and "transmission." Which means that although clear in the bulk of the ranges, the edges/transitions get somewhat blurred. Table 7.2 shows the relationship between the voltages and voltage classes of cable systems for selected regions of the world.

Electrical Stresses

The operation of a cable system is very dependent upon the electrical stresses (E) to which it is subjected, for example:

- Dielectric heating $\propto E^2$
- Probability of failure $\propto 1-\exp(E/\alpha)^{\beta}$
- Insulation aging $\propto E^n$

Thus, to understand the many issues associated with sustainability, it requires a firm understanding of the electric stresses in the whole system.

Alternating Current (AC)

The electrical stress within a cable is given by [1].

$$E = \frac{V}{x \ln\left(\frac{R}{r}\right)} \tag{7.1}$$

where V is the applied voltage, r is the radius over the inner semiconductive screen, R is the diameter over the insulation, and x is the intermediate radius (between r and R) at which the electric stress is to be determined.

The probability of failure depends upon the electrical stress and increases with stress. The effect of an increased stress is most commonly estimated using the Weibull probability function [4]:

$$P_f = 1 - \exp\left\{-\left(\frac{E}{\alpha}\right)^{\beta}\right\} \tag{7.2}$$

where P_f is the cumulative probability of failure, i.e., the probability that the cable would have failed if the stress is increased to a value E. The two parameters, α and β, are known, respectively, as the characteristic stress and the shape parameter.

Inspection of Eq. 7.1 shows that the electric stress varies with the position within the cable. There are three potentially useful stresses that can be considered:

- Maximum stress at conductor screen
- Mean geometric average stress for the whole insulation
- Minimum stress at the core screen

The decision as to which of these to consider is an important one and is guided by the potential modes of failure:

- Maximum: The highest level of stress also corresponds to the highest probability of instantaneous failure or, equivalently, the highest rate of electrical aging.

Table 7.3 Average stress levels for selected insulations

Type	Stress (kV/mm)	EHV	HV	MV
Fluid filled	Average at core screen	10.0	8	8
	Average at conductor screen	17	14	10.0
EPR	Average at core screen	4	3	2
	Average at conductor screen	8	5	3
XLPE	Average at core screen	5.0	3	2
	Average at conductor screen	11	6	3

This is most important if the most serious cable defects are located on or near the conductor screen.

- Mean: This is most important if the most serious defects are uniformly located throughout the bulk of the insulation.
- Minimum: This is most important if cable system reliability is determined by the performance of accessories or if the electrical design or installation method of accessories degrades cable performance. It is also important if the most serious cable defects are located on or near the core screen.

The range of electrical stresses employed is shown in Table 7.3.

Direct Current (DC)

The stress in AC cables is determined by the capacitance (permittivity) of the structure. However, in DC cable systems, the resistance (resistivity) determines the stress [1, 5]. The permittivity of insulations is essentially stress and temperature independent (within the range of normal use), whereas the resistivity has significant voltage and temperature dependence.

Inspection (Fig. 7.2) shows that in the temperature range (20–60°C), the resistivity can change by 2–3 orders of magnitude. The dependence of the resistivity ρ on stress E and temperature T can be characterized equally well by using the formats of Eqs. 7.3 or 7.4.

$$\rho = \rho_0 \exp(-\alpha T - \beta \mathrm{E}) \tag{7.3}$$

$$\rho = \rho_0 \exp(-\alpha T)\mathrm{E}^{-\gamma} \tag{7.4}$$

where ρ_o is the resistivity at reference temperature, α is the temperature coefficient, and β and γ are the stress coefficients of the insulation.

The practical consequence is that the stresses in a DC cable system are primarily determined by the dimensions, voltage, and the temperature distribution. Thus, the design of DC systems is technologically much more challenging than AC. The most obvious manifestation is the difference (with respect to AC systems) of the location of the maximum stress: In AC systems, this is always located close to the conductor (termed Laplace field in Fig. 7.3); in DC systems, this can move from the conductor

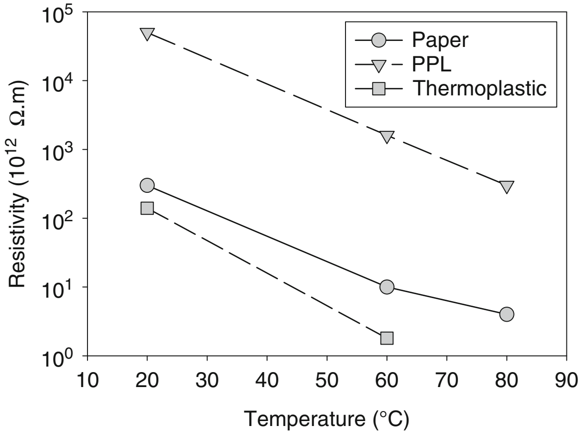


Fig. 7.2 Resistivity of selected insulations at different temperatures

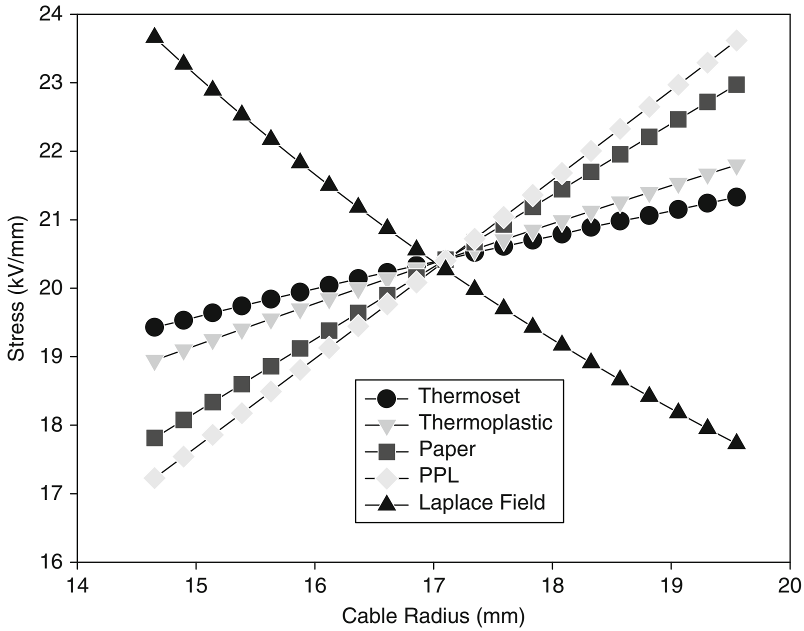


Fig. 7.3 Electrical stress distribution, under load, for a 100 kV DC cable manufactured using different insulants. The power loss *W* is the same for all designs

(no load case) to the outside (highly loaded case) – this is termed stress/temperature inversion.

One of the ways to calculate the electrical stress distribution E_r across the cable insulation at radius *r* can is shown below:

$$\mathrm{E}_r = \frac{\delta V (r/r_2)^{\delta-1}}{r_2\left[1 - (r_1/r_2)^{\delta}\right]} \tag{7.5}$$

$$\delta = \frac{\alpha W/2\pi\lambda + \beta V/(r_2 - r_1)}{\beta V/(r_2 - r_1) + 1} \tag{7.6}$$

where λ is the thermal conductivity, r_1 is the conductor screen radius, r_2 is the radius over insulation, $W = I^2R$ is the conductor loss, and V is the applied voltage. The α and β parameters are extracted from the resistivity data using Eq. 7.3.

Uses of Cables

Power cables are commonly used in underground or underwater (submarine) connections. Cables are placed at strategic points of the transmission grid to supplement overhead lines or, in some cases, they can form the whole "backbone." Interconnections between networks are particularly well suited to cable solutions [3] for security of supply reasons.

Cables may also be used in other applications rather than just underground or underwater. For example, overhead covered conductors allow smaller phase clearance between the conductors on medium-voltage overhead lines. Objects, particularly tree branches, may touch the lines without tripping or customer outage. This has led to substantial improvements in service reliability (e.g., [5]). In most cases, the aluminum alloy conductor is covered with black UV-resistant cross-linked polyethylene and filled with grease, to provide corrosion protection and longitudinal water-tightness. Arcing guides are applied at insulator tops, to protect the line from arcing damage. Another application is the "Powerformer" [6] and the related "motorformer." These new generators are able to supply electricity directly to the high voltage grid without the need for a step-up transformer. It is suitable for power generation at output voltages of several 100 kV. One example of this is the Troll motorformer project on an natural gas rig in the North Sea. The new concept is based on circular conductors for the stator winding, and it is implemented by using proven high-voltage cable technology. Thus, the upper limit for the output voltage from the generator is only set by that of the cable.

AC and DC Transmission

Cable systems are used in both alternating current (AC) and direct current (DC) schemes. The cable designs used in each case are outwardly very similar and have many identical design elements. However, the detailed engineering and the

Table 7.4 HVDC projects using extruded cable systems

Project	Type of Project	Power MVA	Voltage rating KV	Cable length km	In service Year
Gotland/SE	S	60	80	140	1999
Directlink/AU	TL	180	84	390	2000
Tjæreborg/DK	WIND	8	10	8	2000
Cross Sound/US	S	330	150	82	2002
Troll/NO	OFF	80	60	70	2004
Estlink/FI	S	350	150	105	2006
Valhalla/NO	OFF	78	150	292	2009
NordEon/DE	WIND	400	150	390	2009
Transbay/US	S	400	200	95	2010

S Subsea Interconnection, *OFF* Offshore Power Supply, *WIND* Windpower Delivery to Shore, *TL* Trading Link

materials used are very different. AC is the globally preferred means of transferring electric power. This form of transfer makes it straightforward to generate electricity and to transform voltages up and down. This means of transfer accounts for more than 98% of the global power infrastructure.

In long-distance transmission schemes, especially those that are of interest in the future such as windfarms or solar plants, there are very significant advantages in using DC over AC. System instabilities caused by connecting regions with slightly different AC phases and frequencies are obviated. Capacitive charging current implies that there is a maximum useful length of AC cables without the use of shunt reactors. DC cables are therefore particularly useful for long-distance submarine connections. Furthermore, the lack of electromagnetic effects under DC conditions eliminates the skin effect in which the conductor resistance can rise by up to 20% at 50 Hz. The drawbacks for a DC solution are that the terminal equipment for AC/DC conversion is seen as more costly and less efficient than AC transformers. (Reviews on AC/DC power transmission are contained in [7].) Thus, the system must be sufficiently long to be economically viable. In addition, the control of the electrical stress in a DC cable insulation is also much more difficult due to thermally induced stress inversions and stress modifications due to trapped space charge. The space charge issues are particularly onerous at interfaces, such as those that occur at accessories (joints and terminations).

Before 2000, cables using lapped/impregnated (oil or compound) insulations were almost exclusively used for DC transmission up to 500 kV and very long distance. Even today this technology is preferred for the highest voltages (EHVDC) and distances. However, the recent development in the HVDC and lower power range has seen the symbiotic development of cable systems and converter technologies. The pace of this development has been quite rapid such that the current installed lengths (not at similar voltages) of paper and extruded cables are approximately equal at 22,500 km. A selection of HVDC projects using extruded cables is shown in Table 7.4.

Cable Types

There are, in general, four types of underground power cable technologies in use today:

- *Polymeric*: Cross-linked polyethylene (XLPE), water tree retardant cross-linked polyethylene (WTRXLPE), or ethylene propylene rubber (EPR).
- *Self-contained fluid filled (FF or LPOF or PILC)*: Paper or paper polypropylene laminated (PPL) insulated with individual metal sheaths and impregnated with a dielectric fluid. Where used these are common in land cable applications. This type of cable is one of the first to be installed in the 1890s.
- *Mass impregnated non-draining (MIND or solid)*: Paper insulated with individual metal sheaths and impregnated with an extremely high viscosity poly-butene compound that does not flow at working temperatures – common at MV and submarine HVDC.
- *High pressure fluid filled (Pipe Type or HPOF)*: Paper insulated and installed in trefoil in steel pressure pipes and impregnated with high pressure nondegradable fluid which is maintained at high pressures by pumping plants – common in USA at HV & EHV.

The typical electrical stresses employed in cables are shown in Table 7.3.

Up until the mid-1980s, paper-insulated cables (PILC, MIND & LPOF) were the system of choice at medium and high voltages. However, improvements in polymeric cables and accessories plus environmental concerns with the impregnation (dielectric fluid and the associated lead sheaths) have led to a significant reduction in the use of paper cables for land applications. In particular, at MV, there has been a strong preference for XLPE & WTRXLPE cables over EPR (except in Italy and USA). XLPE/WTRXLPE and EPR have emerged as the favored polymeric insulations through the 90°C continuous operating temperature that can be achieved when they are used. This temperature matches that which can be attained when fluid-filled lapped insulations (paper and PPL) are used. In contrast, LDPE and HDPE are limited to operating temperatures of 70°C and 80°C, respectively. As a consequence, these insulations have fallen into disuse.

Tables 7.5 and 7.6 identify some of the main advantages of the respective technologies at distribution and transmission voltages.

The situation today is:

- Almost all new HV and EHV systems that are being installed are new build/expansion.
- The majority of HV cables, *already installed* within the existing system, are insulated with paper (83% paper and 17% polymeric).
- There is very little replacement of existing paper cables: Most of installed capacity is based on paper.
- Most HV transmission is by overhead lines (OHLs).
- HV cables are replacing OHLs in environmentally sensitive areas but there is limited impact (globally) on new OHLs.

Table 7.5 Advantages (+) and disadvantages (−) of MV cable insulations

XLPE 11–46 kV	EPR 11–46 kV	WTRXLPE 11–46 kV	Paper 11 to 46 kV (PILC and MIND technologies)
+ No risk of oil leakage	+ No risk of oil leakage	+ No risk of oil leakage	– Oil leakage in PILC technology 0 Reduced compound leakage in MIND technology
+ Very low dielectric losses	0 Medium dielectric losses	+ Low dielectric losses	– High dielectric losses
+ Simple accessory designs which require competent workmanship	+ Simple accessory designs which require competent workmanship	+ Simple accessory designs which require competent workmanship	0 Simple/robust accessories which require high level of workmanship – installation skills disappearing with aging of the workforce
– Likely to suffer from water trees if no metal sheath	0 Less likely to suffer from water trees if no metal sheath	0 Less likely to suffer from water trees if no metal sheath	+ Metal sheath required to contain fluid, thus water is excluded
0 Standard Size	0 Standard Size Reduced size available in special designs	0 Standard Size	+ Small size – higher design stresses – important for installation in ducts

Table 7.6 Advantages (+) and disadvantages (−) of HV & EHV cable insulations

XLPE 66–500 kV	EPR 66–138 kV	Paper 66–500 kV (low-pressure and high-pressure technologies)
+ No risk of oil leakage	+ No risk of oil leakage	0 Oil leakage is a concern
+ Simple design	+ Simple design	– Complicated design – High maintenance burden
+ Very low dielectric losses	0 Medium dielectric losses	0 Medium dielectric losses
+ Acceptable fire performance	+ Acceptable fire performance	– Fire performance in tunnel and substation applications is a concern due to the copious supply of flammable oil
+ Simple accessory designs which require high level of workmanship	+ Simple accessory designs which require high level of workmanship	0 Simple accessories which require high level of workmanship – installation skills disappearing with aging of the workforce
0 Growing track record	– Limited track record	+ Extensive track record
– Likely to suffer from water trees if no metal sheath	– Likely to suffer from water trees if no metal sheath	+ Metal sheath required to contain fluid, thus water is excluded
– Large size	– Large size	+ Small size – higher design stresses

- XLPE cables make up 80–90% of the HV cable capacity *presently being installed.*

  The reasons that there has been little replacement of paper cables are:

- Paper cables continue to operate reliably.
- Operating temperatures have been considerably below the temperature limits
- The designs of XLPE cables are too large to fit existing rights of way or pipes that have been designed for paper cables. This is of special importance in the USA where there are many paper cables and small tight ducts. In this area, the key task is to develop polymeric cables designs that are flexible, small (i.e., working at high stresses), and easy to join as it is essential to use the existing pipes/ducts. Present designs address these issues, and now, cables exist that match the size and performance of paper cables [8, 9].

Components of the Cable

Conductor

Conductors in the USA tend to be based on the American wire gauge (AWG), but, in the rest of the world, are based on IEC228 and are therefore described using the metric convention. Stranded conductors have generally comprised concentric layers, but, in order to make them smoother and more compact, they are often specially shaped in rolling mills nowadays. When operating at high voltages and currents, the AC current is preferentially carried more in the outer than in the inner conductors (the skin effect). In addition, the electromagnetic fields induce eddy currents (proximity effect). These effects tend to increase the conductor resistance under AC above that which is seen under DC. The AC/DC ratio ($R_{AC/DC}$) can be as large as 1.15. This increased resistance serves to increase the Joule heating losses within the conductor and increases the temperature of the cable. Thus, special “Milliken” conductors may be used for large conductor designs to reduce the AC/DC ratio.

Conductors are virtually all made from either copper or aluminum. Copper has the advantage of being more conductive, and therefore, requires less material to carry a given current. Copper conductors, therefore, have the advantage of being small. However, the cost of aluminum, although variable, is lower than that of copper, and even though it has a lower conductivity, it is often used as the conductor. An additional advantage of aluminum over copper is that the conductors are lower in weight even though more volume of material is used. At MV, aluminum is preferred whereas, at HV and EHV, the smaller size of copper provides the greatest advantage.

Semicon

Semiconductive screening materials are based on carbon black, manufactured by the complete and controlled combustion of hydrocarbons. The carbon conducting medium is dispersed within a paper or polymer matrix depending upon the type of cable involved. In early designs of polymeric cable, paper tapes or painted carbon screens were used. These displayed extremely poor service performance as they were seen to dramatically accelerate the growth of water trees. In these cases, failures occurred many years short of the anticipated design life. Current designs of polymeric cables (XLPE, WTRXLPE, or EPR) use extruded polymeric materials to construct the semiconducting screen. Optimal performance is obtained when the screens are coextruded with the insulation in a closed “true triple” extrusion head.

The concentration of carbon black, in both paper and polymeric screens, needs to be sufficiently high to ensure an adequate and consistent conductivity. The incorporation must be optimized to provide a smooth interface between the conducting and insulating portions of the cable. The smooth surface is important as it decreases the occurrence of regions of high electrical stress [10]. To provide the correct balance of these properties, it is essential that both the carbon black and polymer matrix be well engineered.

The same care needs to be paid to the manufacture of the matrix materials (paper or polymer) for semicons as for the insulation. In the case of extruded screens, the chemical nature of the polymers is subtly different from those used for the insulations because of the need to incorporate the carbon black. The carbon black and other essential additives (excluding cross-linking package) are compounded into the matrix. The conveying and compounding machinery used are designed to maintain the structure of the carbon black within a homogeneous mix. Before the addition of the cross-linking package, filtration may be applied to further assure the smoothness of the material, to a higher standard than that provided by the compounding process.

The smoothness of the extruded cable screens is assured by extruding a sample of the complete material in the form of the tape. The tape is optically examined for the presence of pips or protrusions. Once detected, the height and width of these features are estimated, thereby enabling width-segregated concentrations to be determined. When using such a system, care needs to be exercised when examining the present generation of extremely smooth (low feature concentration) screens, as the area of tape examined needs to match the likely number of detected features: Smooth screens require larger areas of examination.

Insulation

It seems clear that, globally, XLPE or its WTRXLPE variants are the most commonly used cable insulations currently being installed. Insulating XLPE compounds need to fulfill a number of requirements. They should act as thermoplastic materials within the extruder and crosshead. They should cross-link efficiently with the application of high temperatures and pressures within the vulcanization tube. They should be immune to thermal degradation throughout the cable manufacture process and operation at the maximum cable temperature for the life of the system. They must display an extremely low occurrence of the features that can enhance the applied electrical stress and thereby lead to premature failure. To deliver these requirements, it is essential that the greatest care is paid to the design and manufacture of the polymer and the engineering of the appropriate cross-linking and stabilizing packages.

The manufacturing technology employed for XLPE compounds to be used for power applications needs to ensure the highest level of cleanliness at all points of the production chain. The sequence comprises three main parts: base polymer manufacture, addition of a stabilizing package, and addition of the cross-linking package. The most common route for cross-linking in cables (XLPE, WTRXLPE, and EPR) is peroxide cure – thermal degradation of an organic peroxide after extrusion causes the formation of cross-links between the molten polymer chains.

Cleanliness

The cleanliness of XLPE and WTRXLPE insulation materials may be assessed by converting a representative sample of the polymer into a transparent tape and then establishing the concentration of any inhomogeneities. This is not possible for monosil as the chemistry occurs immediately prior to the cable extrusion. The inhomogeneities are detected by identifying variations in the transmission of light through the tape. To gain the required level of consistency and sensitivity, the tape is inspected by an automated optical system.

Metal Sheath

For many years, lead or lead alloys were the main materials used for the metal sheath layer. This is principally because the low melting temperature allows the lead to be extruded at a temperature of approximately 200°C over the polymeric cable. The main disadvantages of lead are its high density (11,400 kgm^{-3}) leading to a heavy product; environmental concerns; and the tendency to creep, flow, or embrittle under cyclic temperature loadings. This latter effect has led to a number of cases where the sheath ruptured. There are also environmental concerns relating to the use of lead. Its use may become restricted by European Union (EU) directives. In 2000, the EU Commission officially adopted the waste electrical and electronic equipment (WEEE) and reduction of hazardous substances (ROHS) proposals. The ROHS proposals required substitution of lead and various other heavy metals from 2008. To address these problems a number of materials have been used.

- *Extruded aluminum*: This has excellent mechanical performance but requires a large bending radius and can be difficult to manufacture since it requires corrugations. It can be heavy.
- *Aluminum foil*: This is light and easy to manufacture but small thicknesses (0.2–0.5 mm) do not give mechanical protection; the strength comes from the

polymer oversheath. It relies on adhesive to make a watertight seal, and it can suffer from corrosion.

- *Copper foil*: This is light, easy to manufacture but not as flexible as aluminum foil. It also relies on adhesive to make a watertight seal.
- *Welded copper*: This is strong, robust, and capable of carrying significant current but difficult to manufacture since it requires corrugation and it is difficult to ensure perfect longitudinal welds in practical situations.
- *Welded stainless steel*: This is strong, robust, and capable of carrying significant current but has similar manufacturing difficulties to welded copper.

Oversheath (Jacket)

In addition to the meticulous attention that must be paid to the insulation system, care also needs to be taken with the oversheath layer. One of the earliest lessons that was learned from MIND and PILC cables (where a lead sheath is employed) is that installation damage and corrosion can compromise the metallic sheath [11, 12]. Once sheath integrity is lost, water may enter and impregnant leak out. In these cases failures in service occurred quite rapidly. These issues were soon resolved on neoprene tape or extruded oversheaths were used. When extruded cables were introduced in the mid-1960s, it was believed that there was no longer a need for an oversheath as the insulating polymers were themselves waterproof. However, the phenomena of water treeing soon showed that a good-quality cable jacket was extremely valuable even at the low electrical stresses prevalent at MV.

The vast majority of HV and EHV XLPE cables are of the “dry design” type, which means that a metal barrier is included. The purpose of the metal barrier is to protect the core within from mechanical damage, carry fault and loss currents, and to exclude water from the construction. (The electrical aging rate is significantly higher in the presence of moisture.) The metal barrier is a key part of the cable design and much care needs to be taken as this significantly affects how a cable system may be installed in practice. In a similar way to that at MV, the metal layer is itself protected by a polymeric oversheath. Due to the critical performance needed from the oversheath, there are a number of properties that are required: good abrasion resistance, good processing, good barrier properties, and good stress crack resistance. Experience has shown that the material with the best composite performance is an oversheath that is based on polyethylene.

Cable Manufacture

Stages of Cable Manufacture

The stages in cable manufacture may be summarized as:

1. *Conductor manufacture*: This involves
   - *Wire drawing* to reduce the diameter to that required
   - *Stranding* in which many wire strands and tapes are assembled
   - *Laying up*: the assembly of noncircular (Milliken) segments into a quasi-circular construction
2. *Core manufacture*: This involves
   Paper (LPOF, MIND, PILC) cables
   - *Lapping* in which the core of the cable is formed by wrapping semiconducting and insulation tapes around the conductor with prescribed tensions and paper tape overlaps
   - *Laying up (triplexing)* for three core cables
   - *Drying* which improves the dielectric properties of the cable core and is carried out at elevated temperatures and under vacuum

   Polymer (XLPE, WTRXLPE, and EPR) cables
   - *Triple extrusion* in which the core of the cable is formed comprising the inner semicon, insulation, and outer semicon.
   - *Cross-linking* which is carried out directly after extrusion (peroxide cure).
   - *Degassing* in which peroxide cross-linking by-products are removed by heating offline. The diffusion time depends upon temperature and insulation thickness.
3. *Cable manufacture*: This involves
   Paper (LPOF, MIND, PILC) cables
   - *Impregnation* where the dry paper tapes are impregnated at elevated temperatures with dry/degassed dielectric fluid
   - *Metal sheathing*: the application of a metal impregnant enclosure
   - *Oversheathing*: the application of high strength extruded polymeric oversheath (jacket)
   - *Armouring*: the application of high strength metal components (steel) to protect the cables; essential for submarine cables
   - *Routine testing*: voltage withstand and ionization factor tests

   Polymer (XLPE, WTRXLPE, and EPR) cables
   - *Core taping* during which cushioning, protection, and water exclusion layers inner semicon, insulation, and outer semicon are applied over the extruded core
   - *Metal sheathing*: the application of a metal moisture and protection layer
   - *Oversheathing*: the application of high strength extruded polymeric oversheath (jacket)
   - *Armouring*: the application of high strength metal components (steel) to protect the cables; essential for submarine cables
   - *Routine testing*: voltage withstand and partial discharge tests

Table 7.7 General correlation of extrusion equipment with extruded insulation materials

	MV			HV			EHV		
	EPR	WTR XLPE	XLPE	EPR	WTR XLPE	XLPE	EPR	WTR XLPE	XLPE
Catenary vulcanization 	X	X	X	X	–	X	–	–	X
Vertical vulcanization 	–	–	–	–	–	X	–	–	X
Horizontal vulcanization 	–	–	–	–	–	X	–	–	X

Methods of Core Manufacture for Extruded Cables

All of the production processes will be common to all methods of manufacture, with the exception of the extrusion process where there are three types of peroxide cross-linking methods. (Cross-linking is often referred to as vulcanization or curing.)

- *VCV*: Vertical continuous vulcanization
- *CCV*: Catenary continuous vulcanization
- *MDCV*: Mitsubishi Dainichi continuous vulcanization, often called long land die

In all of these processes, the three layers of the cable core are extruded around the conductor. This un-cross-linked core then passes directly into the curing tube; this is where differences in the processes become apparent. In the moisture cure approach, which takes place offline after extrusion, the manufacturing process is considerably simplified as the length of the tube following extrusion only has to be long enough for the thermoplastic core to cool sufficiently to prevent distortion.

The general relationship between manufacturing method, the insulation technologies, and voltage classes is shown in Table 7.7.

Failure Processes

Power cable systems are designed to be high-reliability products. The failure of a major power cable is likely to have a considerable effect on the power transmission grid and may take several days/weeks to repair. If it is under the sea, it may

Table 7.8 System performance for a 20kV XLPE ([13])

Class	Fault rate (#/year/100 cct km)
Total system	2.0
Third party damage	1.0
Accessories	0.9
Cable	0.1

take months/years to repair and cost well in excess of $3 million (€3 million). Cables have a good service history. The majority of cable failures are caused by external influences such as road diggers or ship anchors. Cable system failures may also occur at joints and terminations.

A study of MV cable systems in France [13] has shown that the failure rate for paper cables is 3.5 failures per 100 cable km per year which compares with a rate of 2 failures per 100 cable km per year for XLPE cables. The failure rate for XLPE has been classified in Table 7.8. This analysis shows that the XLPE cables form the most reliable component of the cable system. Further inspection would suggest that the XLPE cable system is 2.5 times more reliable than the paper system when third party damage is excluded. (It is assumed that a paper cable is as likely to get dug up as an XLPE one!) This estimate may well overstate the case and illustrates one of the major problems of evaluating field failure statistics, namely, the differing ages of the populations. XLPE data are based on a population which is 15 years old whereas the paper data are based on a population that is 30–40 years old; thus, higher failure rates of the paper system are expected since it contains older devices; this would be quite independent of the intrinsic reliabilities of the systems.

The service performance of cable system accessories (joints and terminations) depends upon six essential elements:

- Connector design
- Joint/termination body design
- Installation methods
- Installation quality
- Operating conditions

A more recent study in the USA [11] estimated a median failure rate of 3.5 failures per 100 cct miles per year. Figure 7.4 shows an estimate of how these failures are disbursed by the sources of failure. At first sight, these figures seem to be quite different to the EDF study; however, it should be recognized that there will be considerable variation due to utility and geographical location. For example, the average percentage of failures ascribed to splices is 37%; however, this can range from 5% to 80% depending upon utility. Nevertheless, these studies both show that it is important to consider the cable system as a whole entity.

In general, the causes of insulation breakdown will include the causes listed below. Table 7.9 shows how the types of defects may be related to the failure modes for the different voltage classes of cables. Many of these defects are shown schematically in Fig. 7.5.

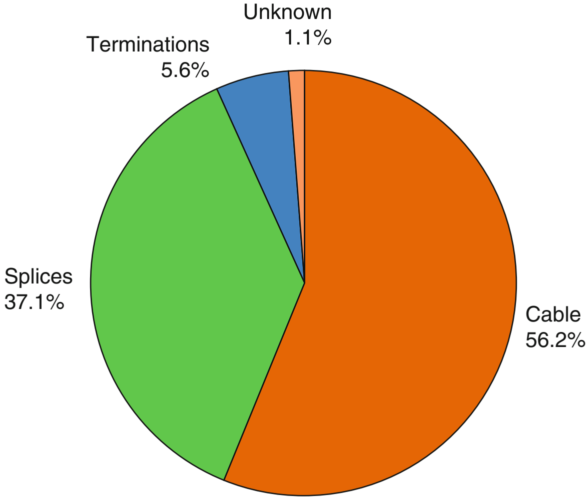


Fig. 7.4 Estimated dispersion of North American MV cable system failures by equipment type

Table 7.9 Role, in general terms, of defects in cable failure modes

Cause of failure	MV	HV	EHV
Extrinsic defects *Contaminants* *Delaminations* *Protrusions* *Shield interruptions* *Voids/cracks*	Accelerants for water treeing	Major source of failure Accelerants for electrical treeing	Major source of failure
Water treeing *Bowtie* *Vented – partial* *Vented bridging*	Major source of failure for extruded	Can be an issue if robust metallic water barriers are not used	Rarely an issue due to the use of robust metallic water barriers
Water ingress	Major source of failure for laminar	Major source of failure for laminar	Rarely an issue due to the use of robust metallic water barriers
Thermoelectric aging	Rarely an issue due to the low temperatures and stresses of operation	Major source of failure accelerated by extrinsic defects	Major source of failure accelerated by extrinsic defects

- Extrinsic defects (contaminants, protrusions, or voids) caused during manufacture or installation. These would normally lead to electrical treeing or direct breakdown soon after production of the void and cable energization.
- Water treeing ("wet aging") caused by water leakage through the sheath or inappropriate design or deployment of a cable without a water barrier. Water trees lead to a weakening of the insulation and electrical treeing or direct breakdown.

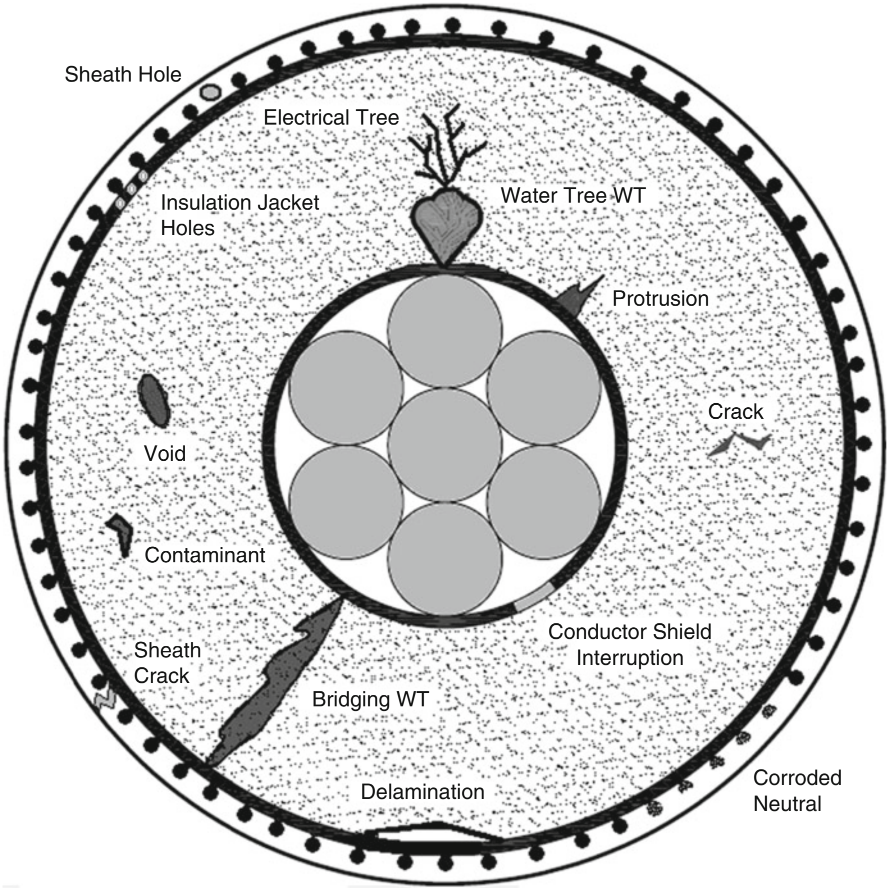


Fig. 7.5 Typical power cable defects

- Water ingress caused by failure of the metal water barriers. Water increases the dielectric loss and thereby leads to local overheating. Failure proceeds by thermal runaway in a region with compromised local breakdown strength.
- Thermoelectric aging: The combination of the electric field, acting synergistically with a raised temperature, causes the insulation to weaken over time and for breakdown to occur eventually. This process may not always be significant within the lifetime of a well-designed cable.

Extrinsic Defects

The efforts made have already been described, from the earliest times, by cable manufacturers to exclude and detect contaminants, protrusions, and voids (CPVs) in their products. Contaminants within the bulk of the insulation and protrusions into the insulation from the semicon cause field intensifications that lead to premature failure of the polymer.

The degree of aging follows the empirical Inverse Power Law relationship with the electric stress ($\propto E^n$) [2, 3, 12, 14, 15].

Contaminants and Protrusions

Many studies [2, 3, 5, 11, 12, 14–18] have shown the degradation caused by large metallic contaminants. Generally contaminants and protrusion type defects reduce the characteristic strengths of insulators; furthermore, the increasing size of contaminants changes the statistical nature of the failures, making them less scattered or more certain.

The effects may be explained by the fact that metallic contaminants increase the electric stress within their immediate locality such that the local electric stress is higher than the breakdown strength of the insulator. This effect is best described in terms of a stress enhancement factor that acts as a multiplier for the Laplacian stress (i.e., the geometrically calculated stress). It is interesting to note that it is possible to get large stress enhancements at sharp metallic contaminants but that the magnitude of the enhancement falls dramatically with distance from the tip; for a 5-μm radius, the field falls by 50% within 1.5 radii of the tip [10]. Thus, the calculated stress enhancements should be viewed as providing the upper limits of any assessment and it is quite challenging to relate them directly to the likelihood of failure.

The electrical stress enhancements are not only based on the size and concentration but they have a significant influence from the nature (conducting, insulating, high permittivity), the shape (sharp or blunt), and the way that they are incorporated into the matrix. The effect of the shape of contaminants has been assessed [18] using XLPE cups with a Rogowski profile. It was shown that contaminants with irregular surfaces reduced the AC ramp breakdown strength by a greater degree than those with smooth surfaces.

The local stress enhancement experienced within an insulator will have contributions from the size of the contaminants, their concentration, and the nature (conducting or high permittivity) of the contaminants. This is shown in Eq. 7.7:

$$\eta = 1 - \frac{1}{\alpha}\left(0.5\ \ln\frac{\lambda+1}{\lambda-1} - \frac{\lambda}{\lambda^2-1}\right) \tag{7.7}$$

where:

$$\alpha = 0.5\ \ln\frac{\lambda+1}{\lambda-1} - \frac{1}{\lambda} + \frac{1}{(k-1)\lambda\left(\lambda^2-1\right)}$$

$$k = \frac{\varepsilon_2}{\varepsilon_1} \qquad \lambda = \frac{1}{\sqrt{1-\frac{r}{a}}}$$

η = stress enhancement factor,
r = radius of the ellipse,
$2a$ = length of the ellipse,
ε_1 = permittivity of the matrix, and
ε_2 = permittivity of the defect.

Voids

Voids are likely to lead to breakdown *if* discharges occur inside them. These discharges are known as "partial discharges" since they are not, in themselves, a complete breakdown or "full discharge." The least problematic (and perhaps the least likely) shaped void is the sphere. The field inside an air-filled, sphere-shaped void is higher than the field in the insulation by a factor equal to the relative permittivity of the solid. For other shaped voids, the field in the void will be higher than this. For example, a void inside XLPE (relative permittivity = 2.3) will have a field inside it of at least 2.3 times that of the field in the XLPE itself. The criterion for a discharge in a void is that the void field must exceed the threshold described by the Paschen curve (see [12] for example); this is dependent on the size of the void and the gas pressure within it. The Paschen field has a minimum for air at atmospheric pressure for a void diameter of 7.6 μm. The breakdown voltage at this diameter is 327 V. This equates to a void field (ignoring the nonlinear effects) of 43 kV/mm or an applied field of 19 kV/mm within the XLPE. Below this void size, the Paschen field increases rapidly; for example, a 2-μm void would require an applied field of approximately 150 kV/mm to cause discharging. It is clear then that voids of diameter exceeding a few microns are likely to allow severe electrical damage to occur.

Partial Discharges and Electrical Treeing

In an electrical discharge, electrons are accelerated by the electric field such that their kinetic energy may exceed several electron-volts. With such energies, collisions with gas molecules may cause further electrons to be released, thus strengthening the discharge or they may cause electroluminescence and the release of energetic photons. The surface of the void is therefore likely to be bombarded by particles (photons or electrons) with sufficient energy to break chemical bonds and weaken the material. In the case of sharp protrusions or contaminants, which give rise to high local electric fields, electrons may be emitted and very quickly acquire the kinetic energy required to cause permanent damage to the insulation. Electrons may accumulate – i.e., they may be trapped – around such defects and cause a further increase in local electric fields. Mechanical stress, which may already be increased due to the modulus and thermal expansion coefficient differences between the host materials and the CPVs, may be further enhanced by electromechanically induced stress. These effects, catalyzed by CPVs in an electric field may lead directly to a breakdown path, but are more likely to lead first to the formation of an electrical tree.

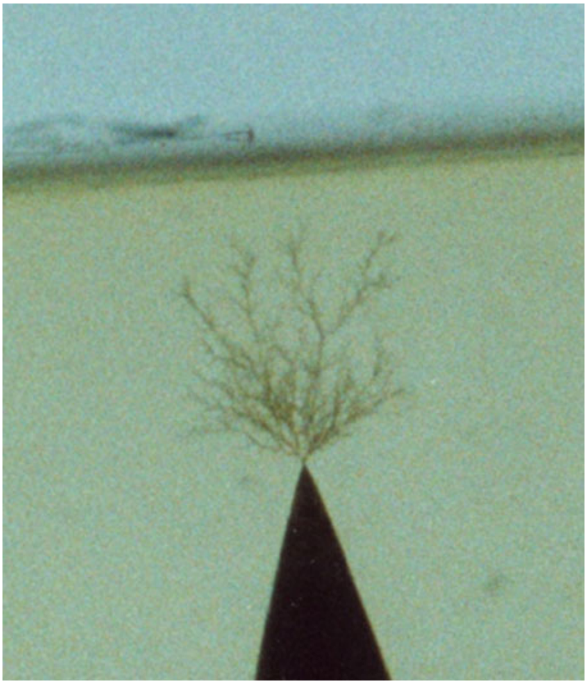


Fig. 7.6 An electrical tree grown in epoxy resin

An electrical tree is shown in Fig. 7.6. For the sake of clarity, this has been grown in a translucent epoxy resin from a needle acting as a protrusion. A breakdown path can be seen to be growing back through the electrical tree from the plane counter-electrode. Electrical trees have a branched channel structure roughly oriented along the field lines. Typically, the diameters of the channels are 1–20 μm, and typically, each channel is 5–25 μm long before it branches. There is considerable evidence that the branching is determined by the local electric field, which is grossly distorted by trapped electrons emanating from the discharges within the tree. There is a considerable body of work on this subject (e.g., [12]). Trees tend to grow more directly across the insulation if they are spindly, so-called branch trees. The other type of tree, the "bush" tree, uses the energy to produce a lot more dense local treeing and, therefore, tends to take longer to bridge the insulation. Because branch trees occur at *lower* voltages, there is a non-monotonic region between branch and bush growth in which failure occurs more quickly at lower voltages. Trees grown from larger voids can be clearly distinguished from those due to protrusions; it is noticeable that the fields must cause the voids to discharge before the trees initiate. After an initial period in which the tree grows fast, the rate of growth decreases. Finally, as the tree approaches the counter-electrode, a rapid runaway process ensues.

Although the electric tree processes are now quite well understood, apparently little can be done to prevent electrical tree propagation in polymeric insulation once it has started. It is thought that electrical trees take relatively little time to grow and cause breakdown in cables, perhaps a few minutes to a few months. Once an electrical tree has been initiated, the cable can be considered to be "terminally ill." It is therefore vital to prevent the inclusion of CPVs during cable manufacture and installation. The triple extrusion continuous vulcanization techniques and appropriate cable protection and deployment techniques appear to have been successful in this regard, and cables rarely suffer from these problems. There are more likely to be problems at joints or terminations where high field stresses may inadvertently be introduced or if water trees, described in the following section, are allowed to grow.

Interaction Between Moisture and Temperature

One of the effects of water entering an insulation is that it tends to increase the permittivity and loss of the insulation [1, 19, 20]. The energy lost per cycle within an insulation is proportional to both the permittivity and the loss. Thus, at a given electrical stress, the increasing energy loss due to the presence of water will lead to an elevated temperature. If this temperature becomes too high, other mechanisms come into play and there is a thermal runaway to failure.

Although this happens in principle in all insulations, and may be very important at the high stresses of HV & EHV systems, this is most commonly observed in paper-insulated MV cables. The sensitivity of these cables is due to the fact that the dielectric losses are initially much higher and the paper and oils have a higher propensity to absorb water. Some basic measurements were made by Blodgett [19] who showed that the loss in paper insulations increased with both temperature and moisture. These data can be used within cable system rating models to estimate the thermal equilibrium for selected temperatures and moisture contents. The results are shown in Fig. 7.7 which shows the increment above the base-case temperature in the form of a contour-plot for selected moisture contents and temperatures. Inspection shows that significant temperature rises can be expected for quite reasonable moisture contents. A separate study has shown that cables removed from service but not failed might be expected to have a median moisture content of 1%, but cables that failed had moistures in excess of 3%. Thus, the thermal runaway mechanism seems to be a reasonable explanation of the observed phenomena. Moreover, the calculations show the difficulty of setting wide-reaching criteria; a common empirically determined maximum permitted moisture level is 3%. However, the impact of this level of moisture is quite different for different cables and temperatures: 3°C, 7.5°C, 14°C for 15 kV/90°C, 35 kV/90°C, and 35 kV/105°C, respectively.

Wet Aging: Water Trees

In the early days of polymer-insulated cables, it was assumed that the polymers would be essentially immune to the deleterious effects of water that were well

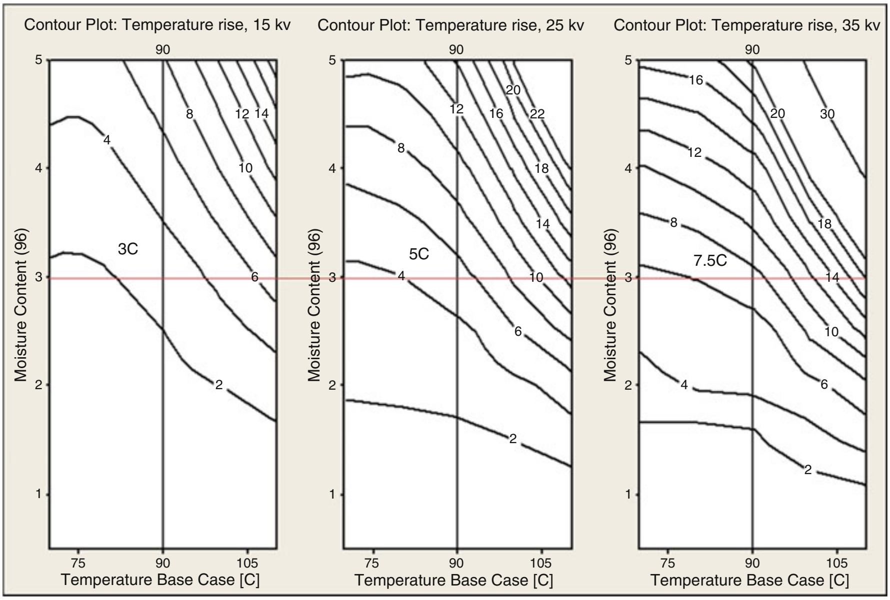


Fig. 7.7 Contour plot of temperatures increment (°C) above base-case temperature for selected base temperatures and moisture content. The calculations have been made for three difference cable voltages

known in paper cables. Consequently, the first designs of cables were installed with little or no water precautions. Within a few years, a large number of cables started to fail in service. Upon examination, tree-like structures were seen to have grown through the insulation. It was assumed that they continued to grow and failure occurred when the whole insulation was breached. This is the phenomenon of water treeing [1–3, 21].

Many studies have been carried out into the phenomena and its solution. Looking back, it is clear that a number of improvements in cable design, manufacture, and materials have reduced the incidence of cable failures by water treeing. These improvements have included

- Water barriers (metal or polymeric) to exclude the water
- Triple extrusion (all polymer layers extruded at the same time)
- Semiconductive polymer screens to replace carbon paint or paper tapes
- Cleaner insulations
- Smoother semicons
- Internationally recognized approval methods
- Special long life insulations based either on additives or polymer structure

The laboratory studies have concluded that the growth of water trees is affected by:

- Test voltage
- Test frequency

- Mean temperature
- Temperature gradient
- Type of material
- Presence of water (external and within the conductor)

There are essentially two types of water trees: (a) vented trees that grow across the insulation and are potentially the most dangerous and (b) bow-tie trees that grow across the insulation and tend to grow to a limiting size without breaching the insulation. These trees do *not* comprise tubules containing water as might be surmised from the earlier description of electrical trees. The "branches" of a water tree actually appear to comprise a high density of water-filled voids of typical diameter 1–10 μm. Such branches are therefore similar to a "string of pearls," but in practice, even branches of water trees are not usually discernible. They are simply diffuse regions of water-filled voids. If dried up, re-immersion in water reopens the voids. Boiling stabilizes the structure but probably also produces extra small voids. There is limited evidence that a percolation network does interconnect the voids, but the size scale of the interconnecting features is at around 10 nm. Electrolyte material accompanies the water into the voids and the ability of cationic dyes, such as rhodamine B, to stain the trees permanently indicates that some oxidation must have taken place. Chemical modification has also been shown using IR and FTIR spectroscopy and by fluorescence techniques.

Water trees grow much more slowly than electrical trees. Typically, they may not be observed at all for several years, even if the prevailing conditions for their growth are in place. They will then grow fast initially and then very slowly. Indeed, in the case of bow-tie water trees, there is much evidence that they stop growing completely after a given length (dependent on prevailing conditions) and that they might not precipitate breakdown. Vented water trees may cross the insulation completely without breakdown occurring, but they do greatly weaken the insulation. Generally, an electrical tree or a breakdown path may grow back through an electrical tree.

It is important to recognize that water trees occur in all extruded insulations (EPR, WTRXLPE, XLPE) and have been found in failure locations retrieved from service. It is often suggested that the water tree–retarding insulations (EPR and WTRXLPE) do not grow water trees. Unfortunately, this is not correct, though it is more difficult to detect water trees in these insulations; however, this is due to the lower initiation and growth rates (EPR and WTRXLPE) and the opaque nature of the insulation (EPR). Nevertheless, longer endurances and lower failure rates are seen for EPR and WTRXLPE for comparable designs and ages, with respect to cable XLPE analogues.

There are many proposed mechanisms of water treeing and these have been critically reviewed in Reference [12]. Essentially, it is likely that solvated ions are injected at partially oxidized sites. These catalyze further oxidation by maintaining the ion concentration. A sequence of metal-ion-catalyzed reactions is proposed in which bonds break and cause microvoids to develop. Alternating electromechanical stresses open up pathways for solvated ions; these initiate new microvoids. Many tree-retardant polymers contain "ion catchers" to prevent the metal ion catalysis, and these have been found to successfully delay the onset and growth rate of water trees.

The tree inception time, i.e., the time between the conditions being right for water tree growth and the first observation of water trees, is highly dependent upon the electrical stress. Typically, the inception time is inversely proportional to a high power (≈4–10) of electric field. For this reason, low-voltage cables, which tend to run at lower electric fields, may not have a water barrier to prevent water ingress and hence electrical treeing. In such cases, with fields typically <4 kV/mm (see Table 7.3), the probability of failure through electrical treeing is low and a water barrier would make little difference. HV and EHV polymer–insulated cables generally use water barriers, and these become mandatory above 66 kV. Furthermore, the conductor is often water blocked (a water-swellable compound or an extruded mastic) to prevent the transport of water along the conductor. The water may enter the conductor either after a cable breakdown or during installation or through an incorrectly installed accessory.

Dry Aging: Thermoelectric Aging

The requirement for extra high voltage (EHV) underground power cables is increasing [1, 2, 12, 14, 22, 23]. There is commercial pressure to push the mean electric field in the insulation of such cables toward 16 kV/mm, and the most common insulation used is cross-linked polyethylene (XLPE). Long-term experience of XLPE, however, is limited to moderately stressed cables with mean fields of 5–7 kV/mm. Furthermore, the introduction of cross-linking processes has permitted the continuous operating temperature of polymeric cables (XLPE and EPR) to be increased to 90°C, equaling that of oil-filled (LPOF and HPOF) paper and polypropylene paper laminate (PPLP) cables. The use of XLPE as the insulation for transmission cables has grown steadily since the early 1990s. Many extruded power cables have been operating for 20 years and are approaching the end of their 30-year design life. If robust methodologies could be found for improving or/and evaluating the reliability of AC power cables, it may be possible to continue to use them without compromising the reliability of the system. Such methodologies require considerable improvements in the understanding of any aging or degradation mechanisms of cable insulation. They would enable XLPE cables to be more competitive at EHV levels.

Future Directions

When looking at the history of underground power cable systems, it is possible to discern a number of rather constant trends:

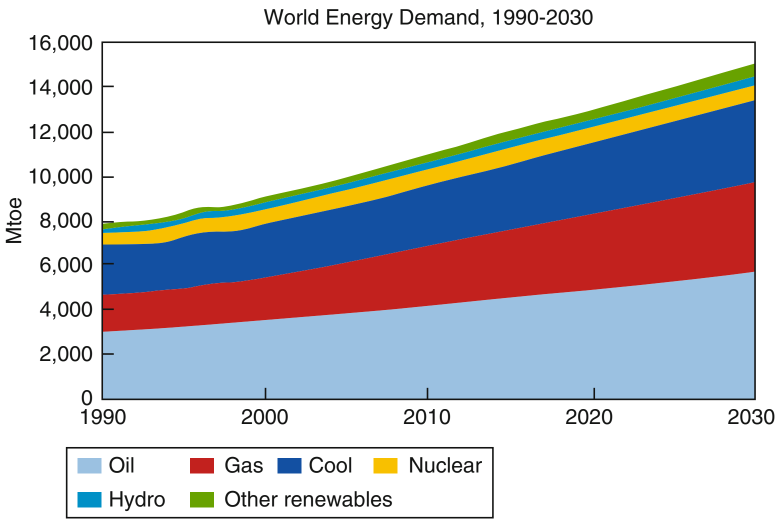


Fig. 7.8 Estimated world energy demand including split of primary energy sources [24]

- Longer length systems get installed as service experience increases.
- Utilities are looking for technologies with easier and less expensive installation and maintenance.
- Manufacturing and material technologies permit higher operating stresses leading to reduced wall thicknesses.
- Reduced wall thicknesses:
  - Lower the total installed system costs
  - Improve the thermal capacity
  - Place greater strains on the accessory and cable installation practices
- End users are looking for longer lives, though the end of life criteria remain undefined.
- Higher reliabilities for systems.
- Public pressure on the location of transmission lines underground.
- Increasing use of underground distribution cables in urban and suburban areas.

It seems clear that all of these trends will continue in the foreseeable future.

Considering the growth of energy requirement (Fig. 7.8), the increasing environmental awareness and the ever-growing level of information transfer, it can be seen that there will be a need to widen our future considerations to include:

- Much lower levels of electrical losses within the transmission and distribution systems – required for increased efficiency
- Higher attention to electric and magnetic field issues – required for increased acceptance of cable systems

- Even higher levels of urban undergrounding to improve the visual environment – required for increased acceptance of electric energy [25, 26]
- Integration of data and energy transmission – required for increased control and optimal use of corridors
- Improved levels of power delivery reliability as there is increasing reliance on more electrically powered systems – required for increased customer satisfaction

There can be no doubt that the use and importance of cables will increase. The areas where most activity will be seen are:

- Understanding life expectancy of cable systems
- Improving cable performance with respect to aging
- Recyclable/recoverable cable designs
- Increased use of long length links
- Diagnostic trends for cable systems
- Impact of smart grid initiatives
- High temperature superconductivity (HTS)
- Gas-insulated lines (GIL)

Understanding Life Expectancy of Cable Systems

Utilities the world over continue to strive to increase the useful life of their underground or subsea cable system assets. However, this activity is taking place in an environment where there is an absence of any actuarial life expectancy or a good understanding of the factors that determine the end of useful life of a cable system. This does not mean that some of the causes of failure are not understood, in fact an extensive amount of work has been done on early failures in the 15–30 year range (e.g., water treeing, effects of contaminants). Thus, the life estimate for cable systems of 40 years is difficult to justify in any rigorous way.

A good example of the issues is the case of MV PILC cables installed in the USA [11]. These cables make up 15% of the total US installed capacity; however, in certain critical locales, this can rise to 80%. The median age of the oldest of these cables is 80 year with lower and upper quartiles at 70 and 90 years. Yet these cables are not failing at a rate that is discernibly higher than the average population of PILC cables: median age of 44 years. Thus, it is not possible to classify them as reaching the end of life because they are old or when they have not reached the right-hand portion of the “bathtub curve.” It is equally unhelpful to assert that these cables have an infinite life as it is known that the paper and oil components will inexorably degrade.

These concerns become important when considering the economics/reliability and sustainability of any technology: The impact of a system that might last for 60 years is considerably less than today’s arbitrary estimate of 30–40 years.

Improving Cable Performance with Respect to Aging

If one builds on the life expectancy concepts discussed previously, then it becomes possible to ascribe a value to technologies that might increase that longevity. Figure 7.9 shows the financial benefits of improved reliability within MV system. The experience over the recent past has shown that the most efficient way to measure and assure cable reliability is to require long-term wet aging tests (CENELEC – 2 years and ICEA – 1 year) with success levels that comfortably exceed the specified minimums.

The total cost perspective of two cable installations is shown in Fig. 7.9. The first shows the classic reference scenario, where the installed cost of cables is higher than the overhead analogue but the total lifetime cost is lower (92%). The second shows the scenario where a longer-lived cable has a longer life (30 years rather than 25 years in the reference) and lower operational costs, due to the better reliability throughout the longer life. Clearly the total cost is lower (82%) for the longer-lived cable. This approach is even more favorable than shown here for the higher-quality, longer-lived, cable; this is because the reference scenario would require that the cable and installation costs be incurred again in years 25–30.

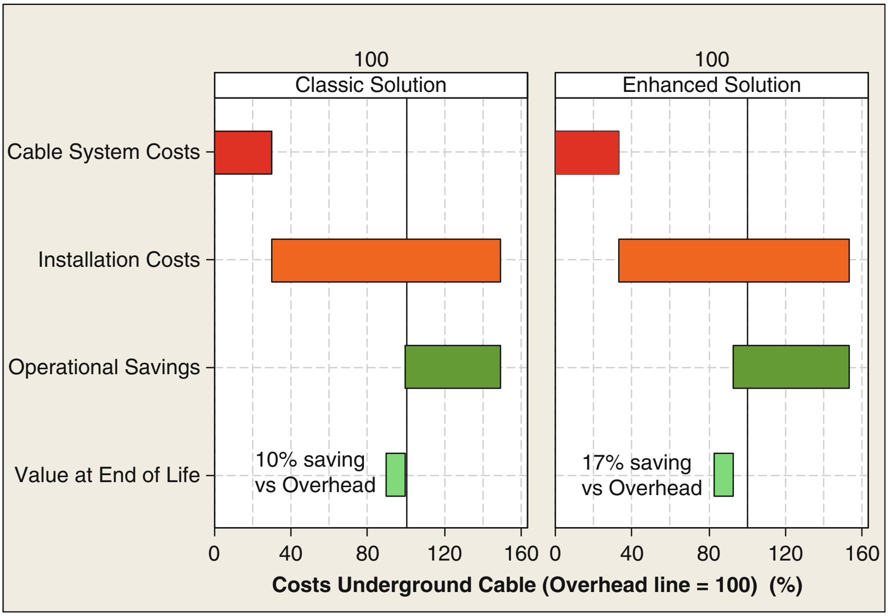


Fig. 7.9 Total cost perspective of two cable installations when compared to an Overhead Line. Initial costs are significantly offset by operational (maintenance, losses, and unreliability – all of these are assumed to be constant over a 30-year period) costs. Two cases are shown: 25 year life is the base case; the other is where a 10% higher cable cost brings higher quality and a 20% increase in life length (30 years)

Table 7.10 110kV Cable versus overhead cost (excluding permitting cost and time). Studies from The Technical University of Graz [26]

Type	Loading conditions	Installed costs (Euros/km)	Operating costs (Euros/km)	Total lifetime costs (Euros/km)	Cost ratio cables to overhead lines
Overhead lines	Low Load	149,000	15,000	164,000	**1.18**
Underground cable		181,000	12,000	193,000	
Overhead lines	High Load	149,000	165,000	314,000	**0.76**
Underground cable		181,000	58,000	239,000	

A similar story is seen at HV: In Austria, a very detailed study of total lifetime costs at 110 kV (Table 7.10) shows that cables have lower costs compared to overhead lines when the normal high loading of lines is considered. The ratios favor overhead lines at low loading but the gap is likely to narrow when the cost of obtaining wayleaves and negative customer/regulator pressure is included [26].

Recyclable/Recoverable Cable Designs

Today there is little activity associated with the recovery of abandoned cable systems as it is believed that there is little economic value associated with them. However, this may well change in the future as:

- There is likely to be public and environmental pressure to rehabilitate the land.
- The cables represent considerable natural resources.
- There will be a pressure to reuse the land previously used for cables and more importantly their associated substations/transformers/switches.

Evidence of these trends can be seen in the recovery of submarine fluid-filled cables (such as those that previously lay in Long Island Sound); here the regulation authorities required their removal as a prerequisite to the installation of new links. This reuses the structures can be seen with the replacement of gas compression cables in Germany and other places with extruded cables; but thie the reuse of the existing pipes/containment structures.

One of the limitations on recycling is the mixed nature of the nonmetallic components, i.e., the insulations and jackets [27]. This is because it is relatively simple to separate metals and metals from paper/plastic. However the plastic separation is not straightforward. Thus, to enable this separation in the future, the key element is the use of a whole polyolefin concept: XLPE and a HDPE jacket. With this approach the material mass is low and there is no expensive ($50/T at 2003 costs) separation step at the end of useful life. The metal within the cable may be reused, and the energy content of the polymer will be liberated and provide a value extremely close to the prevailing cost of oil, which is likely to be significant in 25–30 years' time [27].

Increased Use of Long Length Links

Submarine Cable Systems

Submarine power cables is the term given to cables that carry power underwater. They may be major transmission systems running under the sea, river crossings, or links to islands. Most submarine cable systems, of short to moderate length, are AC, whereas very long lengths employ DC (see later). The reason for the preference for AC is the simplicity of integration with existing infrastructures. The AC embodiments suffer from reactive losses, due to the natural capacitance and inductive properties of wire; hence, there are limitations on length. However, considerable accommodations can be made with solid state control devices and reactive compensation. DC transmission does not suffer reactive losses; the losses in the DC transmission line are the resistive losses. However, the losses in the AC/DC converters need to be included. Furthermore, the converter stations are a considerable capital and maintenance cost. However, from a pure power delivery standpoint, a DC cable system will carry between 1.3 and 1.6 times the power of an equivalently sized AC analogue.

Submarine cables are considerably longer than their terrestrial analogues: hundreds of kilometers versus tens of kilometers. They are laid in very long lengths from a variety of barges or ships. Thus, the manufacture and reliability requirements are much more challenging than for land cables. The importance of these considerations is obvious when the actions for repair after a failure in service are considered. The parties involved need to mobilize considerable marine resources, locate suitable repair materiel, obtain necessary environmental permits, physically attend to the site, retrieve the cable from the ocean floor, effect a repair, and confirm the integrity of the repair. If these elements are not challenging enough, the user and manufacturer need to determine some means to reestablish their confidence in the future problem-free operation of the link. Thus the design, specification, testing, manufacture and installation phases of a submarine project are many orders of magnitude more onerous than a similar terrestrial solution.

Nevertheless, in the future, it is clear that power grids will install larger amounts of submarine cable systems; the drivers will be:

- Increased network interconnection and stability
- Power trading
- Elimination of costly and inefficient local generation (islands)
- Integration of hydro and wind energy
- Reduced public reaction with respect to terrestrial power links

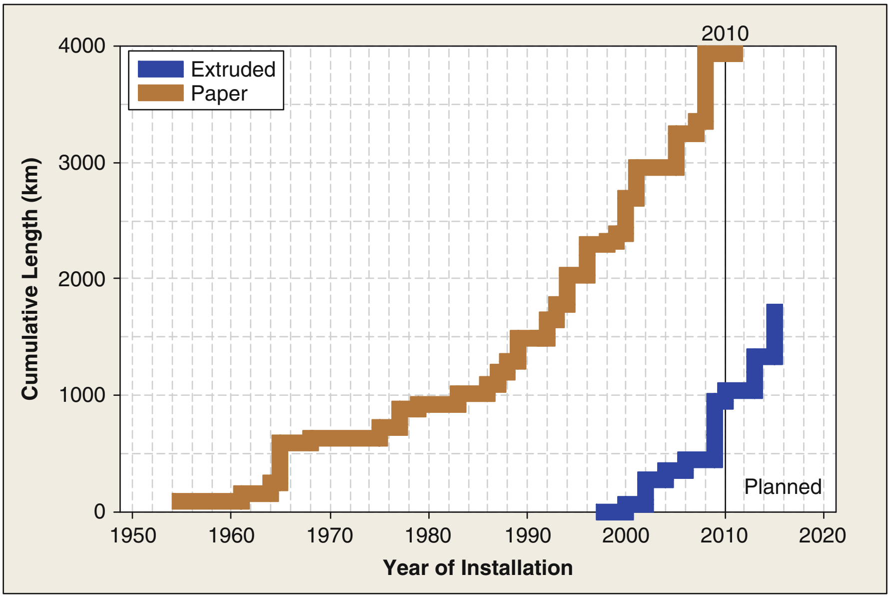


Fig. 7.10 Global installed DC cable capacity segregated by type of cable insulation

Efficient DC Power Transmission

Direct current (DC) power transmission has been shown to be highly efficient for highly controlled long-distance delivery (experience in Nordpool). Long-distance AC transmission is possible (Horns Rev and Isle of Man); however, it requires complex system control and reactive compensation of the cable capacitance. Thus, today the only technology that is capable of delivering long-distance power utilizing underground cables is HVDC. Inspection of the Gotland, Cross Sound, Murraylink, Troll and Estlink projects shows us that voltage source converter (VSC) technology and cables manufactured with cross-linked polyethylene designed for the rigors of DC are already proven and in commercial use. It is interesting to note how many appliances used today operate with DC power supplies (PC, TVs, etc.) – perhaps Thomas Edison had it right all along!!

In the early days of DC, the increased cost of the converters limited its use to EHV grid interconnections (UK/France, Baltic Cable, etc.). However, recent innovations (VSC) in converter technology, cross-linked polyethylene cables, and the flexibility of system design have seen a very rapid growth of DC at high voltage (50–150 kV).

There have been interesting laboratory studies and qualifications of extruded cables using filled insulations at EHV; however, all of the world's commercial installations and the experience shown in Fig. 7.10 has been achieved with specially designed unfilled cross-linked materials. It is clear that unfilled cross-linked technology will be used when extruded cables are integrated into EHV DC systems.

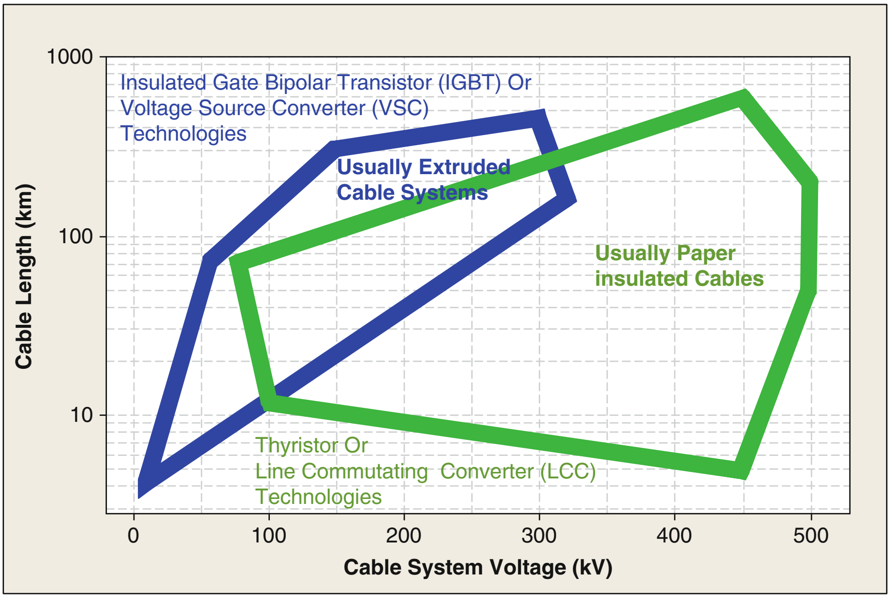


Fig. 7.11 Global installed DC cable capacity segregated by converter technology

The increased use of DC is being supported within the international committees. Specific recommendations have been prepared and published by CIGRE WG 21.01 within Technical Brochure 219. This document provides a very solid base for the extension to extruded HVDC cables. DC cable design presents the engineer with a coupled thermal and electrical problem with the stresses experienced by the cable depending upon the temperature and stress (polarity) inversions. There can be no doubt that HVDC cable design presents as many challenges as EHV ac systems. These include:

- Stress inversions
- Electrical stresses higher than those seen at EHV AC
- Ultralong lengths
- Testing and approvals
- Accessory technology
- System integration

However, as with EHV AC, careful attention to the insulation system makes it possible to succeed with some very impressive projects (Murraylink, Troll, and Cross Sound).

A complimentary aspect is the increasing usage of extruded cables using cross-linked DC polyethylene and voltage source converters (VSC) (Figs. 7.10 and 7.11). These developments have significantly increased the speed of implementation, lowered the total cost, and increased the types of projects for DC systems. It is interesting to reflect in Fig. 7.10 that paper systems required 30 years to achieve

1,000 km of cumulative installed capacity whereas extruded cables within 13 years. It is clear that the trend toward extruded cable systems with VSC technology will increase both in the submarine and terrestrial environments.

Diagnostic Trends for Cable Systems

The use of diagnostics on cable systems is growing and will clearly be an important part of network management for the future. New cables and accessories will probably have features integrated into them that will provide significant amounts of data. Older systems do not benefit from these developments, and thus, a diagnosis will need to be made without optimal sensors and a baseline condition. Nevertheless, considerable advances have been made. However, the challenge for cable and system engineers will come in transforming these data into useful information. Although the new installations will bring exciting opportunities, the major challenge will be associated with the "dumb" cable systems of today and yesterday.

The major areas of activity for diagnostics are:

- Real-time control of cable system rating – This is normally achieved through the use of fiber-optic temperature systems which are coupled to sophisticated thermal models of the cable system.
- Cable system commissioning/acceptance tests – Cable system components are separately tested in the factory; however, there is overwhelming consensus that most of the cable system issues are associated to incidents that occur during installation. Thus, there is a growing trend for cable system acceptance tests which permit these defects to be detected prior to acceptance for service, thereby enabling repair in a timely and cost-effective manner.
- Cable system diagnostic tests [11] – These are tests where the "health" of the cable system is determined, together with essentially a probabilistic assessment of future performance. These results enable a proactive level of asset optimization within the operator.

Real-time control of cable system and cable system commissioning tests are well established, and mature approaches and implementation is proceeding through international standardization bodies such as CIGRE and IEC. In many cases, the challenge is not technical but is the availability of the appropriate knowledge within the user community on the appropriate implementation.

Cable System Diagnostic Tests

Almost all electric power utilities distribute a portion of the electric energy they sell via underground cable systems. Collectively, these systems form a vast and valuable infrastructure. Estimates indicate that underground cables represent 15–20% of installed distribution system capacity. Utilities have a long history of using underground system with some of these cable systems installed as early as the 1920s. Very large quantities of cable circuits were installed in the 1970s and 1980s due to the introduction of economical, polymer-based insulation compounds and the decreasing acceptance of overhead distribution lines. Today, the size of that infrastructure continues to increase rapidly as the majority of newly installed electric distribution lines are placed underground.

Cable systems are designed to have a long life with high reliability. However, the useful life is not infinite. These systems age and ultimately reach the end of their reliable service lives. Estimates set the design life of underground cable systems installed in the range of 30–40 years. Today, a large portion of this cable system infrastructure is reaching the end of its design life, and there is evidence that some of this infrastructure is reaching the end of its reliable service life. This is a result of natural aging phenomena as well as the fact that the immature technology used in some early cable systems is decidedly inferior compared to technologies used today. Increasing failure rates on these older systems are now adversely impacting system reliability, and it is readily apparent that action is necessary to manage the consequences of this trend.

Complete replacement of old or failing cable systems is not an option. Many billions of dollars and new manufacturing facilities would be required. Electric utilities and cable/cable accessory manufacturers are simply not in a position to make this kind of investment.

However, complete replacement of these systems may not be required because cable systems do not age uniformly. Cable researchers have determined that many cable system failures are caused by isolated cable lengths or isolated defects within a specific circuit segment. Thus, the key to managing this process is to find these "bad actors" and to proactively replace them before their repeated failures degrade overall system reliability. Various cable system diagnostic testing technologies were developed to detect cable system deterioration. The results of diagnostic tests are used to identify potential failures within cable systems and then again, after repair, to verify that the repair work performed did indeed resolve the problem(s) detected.

Appropriate maintenance and repair practices enable system aging to be controlled and help manage end-of-life replacements. Diagnostics to determine the health of the cable system are critical to this management program.

A number of cable diagnostic techniques are now offered by a variety of service providers and equipment vendors. However, no one service has definitively demonstrated an ability to reliably assess the condition of the wide variety of cable systems currently in service. Implementing cable system diagnostics in an effective way involves the management of a number of different issues. This includes the type of system (network, loop, or radial), the load characteristics (residential, commercial, high density, government, health care, etc.), the system dielectric (XLPE, EPR, paper, mixed), and system construction (direct buried or conduit). The basic cable diagnostic testing technologies used to assess cable circuit conditions are listed below.

- Time domain reflectometry (TDR)
- Partial discharge (PD) at operating, elevated 60 Hz, elevated Very Low Frequencies (VLF) or damped AC (DAC) Voltages [11, 28]
- Tan δ/dielectric spectroscopy at 60 Hz, VLF or variable frequencies [28–30]
- Recovery voltage
- DC leakage current
- Polarization and depolarization current
- Simple withstand tests at elevated VLF, 60 Hz AC, or DC Voltages [11, 31]
- Acoustic PD techniques
- Monitored withstand tests at elevated VLF, 60 Hz AC, or DC voltages with simultaneous monitoring of PD, tan δ, or Leakage Current [11, 31]
- Combined diagnostic tests at 60 Hz AC, very low frequencies (VLF), or damped AC (DAC) voltages using PD and tan δ

There is no doubt that cable system diagnostic testing can be used to improve system reliability. However, to be effective, the technology should be appropriate to the circuit to be tested. Setting accurate and reasonable expectations is also a critical part of the process.

In general, the work performed in the CDFI [11] led to the following observations:

- Diagnostic tests can work. They often show many useful things about the condition of a cable circuit, but not everything desired.
- Diagnostics do not work in all situations. There are times when the circuit is too complex for the diagnostic technology to accurately detect the true condition of the circuit.
- Diagnostics are generally unable to determine definitively the longevity of the circuit under test. Cable diagnostics are much like medical diagnostics. They can often tell when something is wrong (degraded), but it is virtually impossible to predict the degree to which a detected defect will impact the life of the system tested.
- Field data analysis indicates that most diagnostic technologies examined do a good job of accurately establishing that a cable circuit is “good.” They are not as good at establishing which circuits are “bad.” In most cases, there are far more good cable segments than bad segments. However, it is virtually impossible to know which “bad” circuits will actually fail. Therefore, utilities must act on all replacement and repair recommendations to achieve improved reliability.
- The performance of a diagnostic program depends on:
  - Where diagnosis is used?
  - When diagnosis is used?
  - Which diagnosis to use?
  - What is done afterward?
- A quantitative analysis of diagnostic field test data is very complex. The data comes in many different formats and the level of detail is extremely variable.

However, an in-depth analysis of the data clearly highlights the benefits of diagnostic testing.
- Diagnostic data require skilled interpretation to establish how to act. In almost all cases, the tests generate data requiring detailed study before a decision can be made on whether to repair or replace the tested cable circuit.
- No one diagnostic is likely to provide sufficient information to accurately establish the condition of a cable circuit.

Impact of Smart Grid Initiatives

Much has been written about Smart Grid Initiatives. Smart grid is defined rather differently in Europe and USA; however, one commonality is that the goal is to insert intelligent and interactive devices in the existing grid infrastructure to fulfill a number of goals, such as:

- Better facilitate the connection and operation of generators of all sizes and technologies
- Allow consumers to play a part in optimizing the operation of the system
- Significantly reduce the environmental impact of the whole electricity supply system
- Maintain or even improve the existing high levels of system reliability, quality, and security of supply
- Dynamic optimization of grid operations and resources, with full cyber-security
- Deployment and integration of distributed resources and generation, including renewable resources
- Development and incorporation of demand response, demand-side resources, and energy-efficiency resources
- Deployment of "smart" technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation
- Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning

Thus, it is clear that the existing grid will be operated in a different manner to the one that it is accustomed and that the demands placed upon it will be increased. A natural consequence will be that a number of hitherto unseen failure or degradation modes will become prevalent. It is already possible to postulate what a number of them might be:

- Overheating of nonoptimally designed/installed components, which have not presented themselves due to the lower level of grid loading [32]

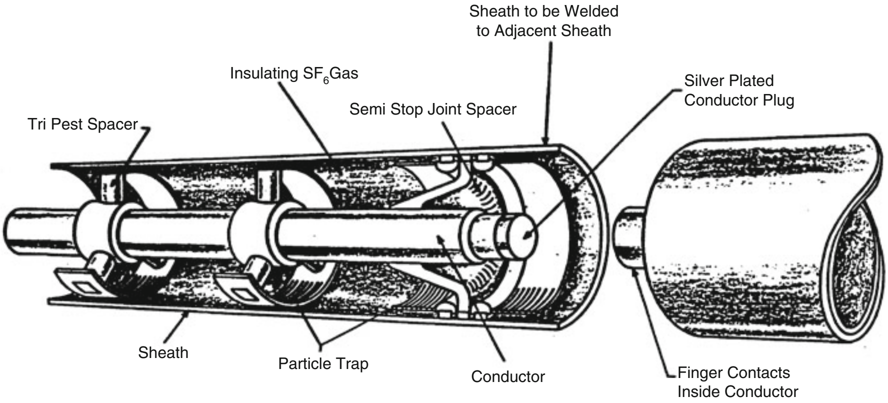


Fig. 7.12 Typical design of a gas-insulated line (GIL)

- Accelerated degradation due to transients/harmonics superposed on the grid by the smart devices themselves, the most obvious are third, and higher, harmonics
- A heightened sensitivity of consumers to power quality issues
- More aggressive load profiles due to changing demand and supply side protocols, as a consequence of reducing the traditional “low load recovery periods”

High-Temperature Superconductivity (HTS)

Equally there are technologies of today that will find some niche uses, but are unlikely to come into immediate and widespread use. The first is high-temperature superconductivity (HTS) that may well find application where people wish to transmit large amounts of power over relatively short distances. However, the issues associated with long-distance cryogenics, termination temperature differences, and complicated start-up procedures need to be addressed before this technology becomes attractive to utilities.

Gas-Insulated Lines (GIL)

Gas-insulated Lines offer the hope of large current ratings, low capacitances, and reduced dielectric losses for longer transmission distances. Yet, in most practical cases, the short lengths, and the associated difficulties of fabrication, plus the large environmental issues around large amounts of SF_6 gas, even in mixtures, will limit its use. By comparison, it would seem that GIL has much wider application than superconducting cables. A typical gas-insulated line design is shown in Fig. 7.12.

Bibliography

1. Moore GF (1997) Electrical cables handbook. Blackwell Science, San Diego. ISBN 0 632 04075 0
2. Densley J (1995) Ageing and diagnostics in extruded insulations for power cables. In: IEEE 5th international conference on conduction and breakdown in solid dielectrics, IEEE publication 95CH3476-9, pp 1–15
3. Fothergill JC, Hampton RN (2004) Polymer insulated cable. In: Haddad A, Warne D (eds) Advances in high voltage engineering. IEE, London, pp 477–507, Chapter 10. ISBN 0 85296 158 8
4. Abernethy RB (1996) The new Weibull handbook, 2nd edn. Robert B. Abernethy, North Palm Beach. ISBN 0965306208
5. Hampton RN (2008) Some of the considerations for materials operating under High Voltage Direct Current Stresses. IEEE Electrical Insulation Magazine 24(1):5–13
6. Leijon M (1999) Novel concept in high voltage generation: Powerformer^{TM}. IEE Conference Publication, v5, n467, 1999. In: Proceedings of the 1999, 11th International symposium on "High Voltage Engineering", 23–27 Aug 1999, London, UK, p 5.379.S5-5.382.P5, IEE, ISSN: 0537–9989 IECPB4 ISBN: 0-85296-719-5
7. Jenkins N (2002) Power Engineering Journal 16(3):90–91
8. Karlstrand J, Sunnegardh P, Zenger W, Ghafurian R, Boggia R (2002) Water-cooled 345 kV solid-dielectric cable system, Cigré paper 21–111
9. Halvarsson P, Karlstrand J, Larsson D, Larsson M, Reinholdsdóttir K, Sigurõsson E (2002) A novel approach to long buried AC transmission system, Cigré paper 21–201
10. Bartnikas R, Eichhorn RM (eds) (1983) Engineering dielectrics, vol IIA, Electrical properties of solid insulation, Philadelphia, ASTM-STP 783
11. Diagnostic Testing of Underground Cable Systems (Cable Diagnostic Focused Initiative) DOE Award No. DE-FC02-04CH11237, December 2010
12. Dissado LA, Fothergill JC (1992) Electrical degradation and breakdown in polymers. In: Peter Peregrinuns for the IEE, London
13. Brincourt T, Regaudie V (1999) Evaluation of different diagnostic methods for the French underground MV network. In: JICABLE'99, Versailles, p 451
14. Peschke E, Schroth R, Olshausen R (1995) Extension of XLPE cables to 500 kV based on progress in technology. In: JICABLE'95, Montreal, pp 6–10
15. Griffiths CL, Betteridge S, Hampton RN (1998) Thermoelectric ageing of cable grade XLPE in dry conditions. Conduction and breakdown in solid dielectrics ICSD '98. Proceedings of the 1998 IEEE 6th international conference, pp 279–282, doi:10.1109/ICSD.1998.709279
16. Coppard RW, Bowman J, Dissado LA, Roland SM, Rakowski RT (1990) The effect of aluminium inclusions on the dielectric breakdown strength of polyethylene. J Appl Phys 23:1554–1561
17. Antoniscki JR, Nilsson U, Gubanski SM (1997) The effect of metal inclusions on the breakdown strength of XLPE cables. In: CEIDP 1997, Minneapolis, pp 283–286
18. Hagen ST, Ildstad E (1993) Reduction of AC breakdown strength due to particle inclusions in XLPE cable insulation. In: Conference on power cables and accessories 10 kV–500 kV, London, pp 165–168
19. Blodgett RB (1962) Influence of absorbed water and temperature on tan delta and dielectric constant of oil-impregnated paper insulation. Trans AIEE 81:93–100
20. Hartlein RA, Hampton RN, Perkel J (2008) Some considerations on the selection of optimum location, timing, and technique, for diagnostic tests. In: IEEE Power Engineering Society (PES) general meeting panel session, Pittsburg
21. Steennis EF (1989) Water treeing: the behaviour of water trees in extruded cable insulation. ISBN 90-353-1022-5, Kema, pp 132–133
22. Gregory B, Griffiths CL, Hampton RN and Mainwaring SP (2000) A probabilistic design method for polymeric structures to operate at high electrical stress. In: 8th international

conference on dielectric materials, measurements and application, IEE Conference Publication no 473, pp 419–424
23. Ogawa K, Kosugi T, Kato N, Kawawata Y (1990) The worlds first use of 500 kV XLPE insulated aluminium sheathed power cables at the Shimogo and Imaichi power stations. IEEE Trans Power Delivery 5(1):26–32
24. International Energy Agency. www.iea.org
25. Gorham and Partners (1995) Undergrounding – A success story already in Europe – Potentially worldwide. Report to ICF Congress 1995
26. Campbell A (2003) Undergrounding HV and EHV – window of opportunity opens. In: ICF Congress 2003, St Petersburg, pp 169–193
27. Hampton RN (2005) Electrical insulation systems for energy technology and clean environment. In: Nordic insulation symposium (NORDIS), Trondheim, June 2005
28. Hampton RN, Olearczyk M, Perkel J, Weisenfeld N (2010) Cable fleet management. IEEE Power and Engineering, Nov 2010
29. Perkel J, Hernández JC, Hampton RN, Drapeau JF, Densley (2011) Challenges associated with the interpretation of dielectric loss data from power cable system measurements. In: International conference on insulated power cables JICABLE11, Versailles France, June 2011, C.4.5
30. Drapeau J-F, Cantin B, Hampton N, Perkel J (2011) Dielectric loss characterization of hydro-quebec medium voltage (MV) submarine cables – phase 1. In: International conference on insulated power cables JICABLE11, Versailles France, June 2011, Paper A.7.6
31. Fletcher CL, Perkel J, Hampton RN, Hernandez JC, Hesse J, Pearman MG, Wall CT, Zenger W (2011) First practical utility implementation of monitored withstand diagnostics in the USA. In: International conference on insulated power cables JICABLE11, Versailles France, June 2011, Paper A.10.2
32. Parker T, Hampton RN (2011) Impact of filled-strand conductor on connector temperature for medium voltage joints. In: International conference on insulated power cables JICABLE11, Versailles France, June 2011, Paper C.1.5

Chapter 8
Energy and Water Interdependence, and Their Implications for Urban Areas

Liz Minne, Arka Pandit, John C. Crittenden, Miroslav M. Begovic, Insu Kim, Hyunju Jeong, Jean -Ann James, Zhongming Lu, Ming Xu, Steve French, Muthukumar Subrahmanyam, Douglas Noonan, Marilyn A. Brown, Jess Chandler, Yongsheng Chen, Eric Williams, Reginald Desroches, Bert Bras, Ke Li, and Michael Chang

Glossary

Anthroposphere	That part of the environment that is developed or adapted by humans.
Life cycle assessment (LCA)	Analysis of the impact of a product or service through all the stages of its life including raw resource acquisition, material processing, fabrication, assembly, transportation, operation, disposal, recycling, repurposing, or reusing.

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3.

L. Minne (✉)
Environmental Engineering, Brook Byers Institute for Sustainable Systems,
Georgia Institute of Technology, Atlanta, GA, USA
e-mail: eliz.minne@gmail.com; liz.minne@gatech.edu

A. Pandit • H. Jeong • J.-A. James • Z. Lu • M. Chang
Brook Byers Institute for Sustainable Systems and the Department of Civil & Environmental Engineering, Georgia Institute of Technology, Atlanta, GA, USA
e-mail: Arka.Pandit@gatech.edu; Hyunju.Jeong@gatech.edu; gtg281w@mail.gatech.edu; Zhongming.Lu@gatech.edu; chang@gatech.edu

J.C. Crittenden
Georgia Institute of Technology, Atlanta, GA, USA
e-mail: jcrittenden3@mail.gatech.edu

M.M. Begovic • I. Kim
School of Electrical and Computer Engineering, Georgia Institute of Technology, Atlanta, GA, USA
e-mail: Miroslav@ece.gatech.edu; iskim@gatech.edu

M. Xu
School of Natural Resources and Environment, University of Michigan, Ann Arbor, USA
e-mail: mingxu@umich.edu

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*, DOI 10.1007/978-1-4614-5830-2_8, © Springer Science+Business Media New York 2013

Low-impact development (LID)	A way of managing stormwater runoff through decentralized water systems, such as green roofs and rainwater harvesting.
Material flow analysis (MFA)	Analysis of how resources move through the industrial, consumer, and ecological sectors.
Resilience	The ability for a structure to maintain its fitness and function in response to indigenous and exogenous stressors; it is characterized by four measures: Rapidity. A measure of the capacity to contain losses or prevent further degradation in a timely manner. Redundancy. A measure of the inherent substitutability. Resourcefulness. A measure of the capacity to mobilize resources to restore functionality in the event of disruption. Robustness. An ability of the system to withstand a given level of stress and/or demand.

S. French • M. Subrahmanyam
Center for Geographic Information Systems and the School of City and Regional Planning, Georgia Institute of Technology, Atlanta, GA, USA
e-mail: steve.french@coa.gatech.edu; subrahmanyam.muthukumar@coa.gatech.edu

D. Noonan • M.A. Brown • J. Chandler
School of Public Policy, Georgia Institute of Technology, Atlanta, GA, USA
e-mail: doug.noonan@pubpolicy.gatech.edu; marilyn.brown@pubpolicy.gatech.edu; jess.chandler@gatech.edu

Y. Chen • R. Desroches
Department of Civil & Environmental Engineering, Georgia Institute of Technology, Atlanta, GA, USA
e-mail: yongsheng.chen@ce.gatech.edu; reginald.desroches@ce.gatech.edu

E. Williams
Golisano Institute of Sustainability, Rochester Institute of Technology, Rochester, NY, USA
e-mail: ericwilliams@asu.edu

B. Bras
George W. Woodruff School of Mechanical Engineering, Georgia Institute of Technology, Atlanta, GA, USA
e-mail: bert.bras@me.gatech.edu

K. Li
Department of Biological and Agricultural Engineering, University of Georgia, Atlanta, GA, USA
e-mail: keli@engr.uga.edu

Sustainability	The development of an anthrosphere that exists within the means of nature. Sustainability requires that humans use no more resources than nature can renewably provide and generate only wastes that nature can assimilate in a timely manner and without overwhelming natural cycles.
Urban heat-island effect	The phenomenon where the temperature in a developed area with a high concentration of buildings, roads, and other physical infrastructure is significantly higher than in the surrounding undeveloped areas.
Urban sustainability	An assessment of the long-term viability of a place considering the physical infrastructure (such as water, sewer, transportation, and buildings), socioeconomic issues (such as human well-being, health, wealth, safety, and security), and natural environment (such as resources, wildlife, and ecosystem health).

Definition of the Subject

There are many definitions for sustainability. Mathis Wackernagel, creator of the ecological footprint concept, defined sustainability as "securing people's quality of life within the means of nature" [1]. The United Nations' World Commission on Environment and Development (the Brundtland Commission) defined sustainable development as "development that meets the needs of the present without compromising the ability of future generations to meet their own needs" [2]. Throughout this report, sustainability will be defined as the development of the anthroposphere within the means of nature. Here, the anthroposphere is the built environment or the environment that humans created for security, wealth generation, and comfort. For it to exist within the means of nature implies that the anthroposphere must use resources that nature provides, and generate only the kind and amount of waste that can be assimilated into the environment without overwhelming natural cycles. At the global scale, there are several examples that suggest that current development patterns are unsustainable. Presently worldwide, there are approximately 7 billion people using 14 Gt of materials [3]. With only 5% of the global material use being renewable, the extraction of natural resources is beyond what nature can reasonably supply. At the other end, an enormous amount of synthetic and potentially toxic materials are being introduced into the global material cycle.

To fully understand sustainability, one needs to take a whole system approach. In the traditional reductive engineering paradigm, each of the individual infrastructure components such as water, energy, and transportation are optimized separately. However, since the function of all the component elements depend on each other, a more optimal solution can occur if all the urban pieces are considered together. These interdependencies form an ecosystem of infrastructure that, if functioning properly, provides a lasting basis for human enterprise. An example of the interdependencies and the need for them to be considered together is the water energy nexus. In all but the most primitive cultures, it takes water to create useful energy and energy to create useful water. This nexus requires a comprehensive understanding not just of power generation or of water resource management, but of both and how they connect and interact at temporal and spatial scales that are both large and small. And on top of these engineering relationships, environmental, social, and economical concerns must also be integrated.

Why is sustainability, particularly urban sustainability, so important? The United Nations Environmental Program (UNEP) chief, Klaus Toepfer, stated in 2005 that "cities pull in huge amounts of resources including water, food, timber, metals and people. They export large amounts of wastes including household and industrial wastes, wastewater and the gases linked with global warming. Thus their impacts stretch beyond their physical borders, affecting countries, regions and the planet as a whole. So the battle for sustainable development, for delivering a more environmentally stable, just, and healthier world, is going to be largely won and lost in our cities" [4]. The UNEP expects 64% of the world's population to live in urban areas by 2040, a dramatic increase from 50.5% in 2010 [5]. For the developed countries like the United States, those in the European Union, and others, the share of urban population is projected to be 87% in the same time period [5]. With such an influx of people from rural areas to urban areas, cities must be prepared for this mass in-migration. With much of this movement expected in developing countries, those that adopt sustainability as a guiding framework for development could leapfrog other countries that are financially and systemically burdened with maintaining the status quo. For the developed world, a hybrid approach in which existing centralized systems are augmented by decentralized systems could help those cities remain competitive and viable. New or old, however, each city has different demographics, cultural values, fiscal and physical constraints, climate, and topology, and any solution to the demand for urban infrastructure – sustainable or not – will have to be uniquely tailored to consider these differences.

Introduction

Transmission grids are an integral piece of urban infrastructure. Understanding how electricity is used and finding ways to decrease the use of energy will be essential for developing more sustainable urban systems. Likely the greatest opportunities for improving efficiencies and increasing sustainability lies not in a single solution, but in how all the pieces – old technology and new – interconnect and work together. Transmission grids not only transmit energy to residencies and workplaces, but also to water treatment systems, to industries, to street lights, to trains, and to the gasoline stations where cars are fueled, just to name a few. These dependencies are not unidirectional, however. Energy production and demand are also significantly dependent on these systems. Pipelines move natural gas, oil, and water to refineries and power plants, while trains and ships transport coal for use in heating, manufacturing, and power production. Adding to this is the emergence of affordable and technologically feasible renewable or decentralized energy options such as photovoltaics, wind power, and microturbines. The most productive, healthy, and sustainable cities of the future will be the ones that learn to use all these resources to build and operate wholly integrated energy systems that meet the short- and long-term economic, social, and environmental needs and aspirations of their residents and region.

Urban areas are complex interconnected systems analogous to ecological food webs. For an urban area to function properly, water, energy, and transportation systems need to be effectively designed to support the area’s desired land use. Similarly, the land-use pattern also should be governed according to the capacity of the area to host development. Beginning in the nineteenth century, these systems have increasingly been designed, built, and operated as isolated systems without considering how they interact. Water purveyors have been concerned about water distribution. Power companies examined energy production, distribution, and usage. Transportation planners examined ways to move people and goods safely and efficiently. Generally, they cared about optimizing their own processes to satisfy their own needs. However, in recent years, some cities have begun to realize that they could improve efficiency by considering how these different systems interact and function together within the whole urban system, rather than as individual and independent parts. For example, energy generation requires water for steam production and cooling. The waste heat from energy production could be used to produce hot water, heat homes, or provide air-conditioning. In another example, a Pacific Northwest National Laboratory study in 2007 suggested that 73% of the United States’ current light-duty vehicle fleet could be supported by the existing electric power infrastructure [6]. It is less clear, however, how the increased electricity demand required to electrify transportation would affect water demand. These are just two simple examples. Socioeconomics, policy, land use, and urban infrastructure form a complex system that makes up the city. When a holistic approach is adopted to analyze the urban infrastructure, many properties emerge that are not apparent when the components are analyzed individually. These emergent properties evolve from the economic and sociopolitical framework adopted by the stakeholders for the urban area. Hence, citizen capacity building, whereby informed citizens demand more sustainable infrastructure, is vital to driving the political agenda to improve the urban infrastructure.

A city is such a multifaceted and complex system that one cannot easily test the effect of certain decisions or actions. However, the impact of decisions can be estimated through modeling that simulates how agents change their behavior in reaction to different options. For example, a first-generation agent-based modeling analysis of urban infrastructure would include the following:

(a) A determination of the spatial and temporal demand for urban infrastructure due to development/redevelopment activities
(b) A listing of infrastructure alternatives that satisfy the needs of the development
(c) A calculation of the material and energy required for the different alternatives
(d) A determination of the vulnerability and resiliency of the urban infrastructure alternatives against exogenous or endogenous risks
(e) An assessment of the local, regional, and global impacts of the alternatives through life cycle analysis

A second-generation model would include feedback loops in which all previous decisions are reconsidered in light of outcomes revealed by the model. This is more realistic because of future decisions do depend on evolving properties. Once the model is verified, the dynamic policies and economic drivers (i.e., market forces) that will yield more sustainable and resilient urban infrastructure can be determined more accurately. More importantly, the model can be used to assess the sensitivity of outcomes to different inputs and resources can be focused on those components that will result in the greatest improvement.

Methodologies

There are many methods for evaluating sustainability. As with all methods, each has strengths and limitations. Some of the methods used to evaluate the sustainability of urban environments are discussed below.

Resiliency

Resiliency is the ability of a structure to maintain its functionality despite exogenous or endogenous stressors. Resilient systems are flexible and adaptable and typically provide a better return on material investments in the long term. There are four important attributes that compose resiliency: robustness, redundancy, resourcefulness, and rapidity. Robustness is the ability of the system to withstand a given level of stress or demand. Redundancy is a measure of the inherent substitutability, or the ease with which a component or a whole system, or the function that they provide, could be replaced in case of a failure. Resourcefulness is a measure of the capacity to mobilize resources in the event of disruption. Rapidity is a measure of the capacity to contain losses or prevent further degradation in a timely manner. These 4 “R’s” can be used as metrics in determining the sustainability of a system or infrastructure [7]. Urban infrastructure that is designed to minimize material and energy investments may not in fact be sustainable in the long term if the reductions result in low resiliency and the functioning of the infrastructure is jeopardized. Resiliency serves as a check against short-sighted, but well intentioned, actions that do not contribute to longer-term sustainability.

Life Cycle Assessment

Life cycle assessment (LCA) is the analysis of the impact of one particular product across all phases of the product's "life." Life can be defined in multiple ways. The most common way an LCA is performed is from cradle-to-grave. This considers raw material extraction, manufacturing, use, and disposal. While a great deal of attention is often paid to a product's manufacturing phase, the use phase is often the most important phase based on a product's impact. For example, a car uses a great deal more energy and resources in the use phase than in the manufacturing phase.

If a product is recycled or reused instead of being disposed of, it is cradle-to-cradle, and the life of the product is extended. For example, plastic soda bottles made of polyethylene terephthalate (PET, recycling symbol number 1) can be recycled to make new plastic bottles or a variety of other products, like T-shirts and carpeting. Cradle-to-cradle aims to reduce waste and decrease the amount of virgin resources that are used in a product.

Other methods may shorten the view of an LCA, such as cradle-to-gate and gate-to-gate. Cradle-to-gate looks at the product from raw resources all the way through manufacture, but ends there. This might be useful particularly to a manufacturing plant or for products that have negligible effect in their use and disposal phase. Manufacturing also might look at a gate-to-gate LCA. This kind of LCA looks only at the production chain. This could be useful in comparing the efficiencies of different manufacturing methods and tools.

Two additional LCA methods that may be employed are the Economic Input-Output LCA (EIO-LCA) and the Ecologically based LCA (Eco-LCA). The EIO-LCA was developed at Carnegie Mellon, and is used to measure the economic effects of the materials and energy used to make a product [8]. Ohio State University developed the Eco-LCA [9]. This tool adds to the traditional cradle-to-grave LCA by emphasizing more analysis on the direct and indirect effects of a product on pollutant emissions and economic flows.

Life cycle assessment is a useful tool when looking at sustainability; however, it does have a number of limitations. Not all factors can be tracked or easily given a numerical value. For example, it is difficult to put a numerical value on the health effects of a product because toxicity and the transport and exposure routes may not be that easy to quantify.

One other limitation of LCA is the cutoff problem. For any product or process there are a large number of product stages or processes upstream and it is never possible to include all of them. Consider, for example, automobile manufacturing. An automobile needs parts for its manufacturing. The parts need a suite of metals. Mining equipment is required to obtain the required metals. But the metal needed for the mining equipment also required machines to obtain it. And so the chain continues.

In LCA, the chain needs to be truncated somewhere resulting in errors of omission. Additionally, the different LCA methods and commercially available software, like SimaPro, that are widely used to conduct LCA may use different assumptions and data resulting in a variation of results that must be reconciled.

Material Flow Analysis

A material flow analysis (MFA) is a process used to assess the flow of mass and energy within a defined system. It can be conducted at national scales, at the scale of a product, or at any scale in between. Urban metabolism is a specific MFA tool looking at a defined urban area. This method tends to look at the city as a "black box." It considers the flows moving in or coming out of the city, but does not necessarily look at the mechanisms inside the city that cause these fluxes to occur. It does give a view of the amount of goods and energy needed to support a city, and how much waste the city produces. However, one constraint is the need for extensive input and output information for a huge number of materials. Some of these numbers are tracked at the national level, or are easy to track within one industry, but may be difficult to find or track for less controlled regions like states or cities. This approach works well for islands because all inputs are brought in by boats and recorded, and outputs also must go out on boat or stay on the island. With better data collection, this method will become increasingly useful. An improvement on urban metabolism would be to track the inflows of resources, the outflows of wastes, and the creation of infrastructure that creates wealth and comfort. The guiding principles would be to use fewer resources to create and operate the infrastructure needed per capita. In practice, it can be difficult to compare one city to another because cities can be in different states of build-out of its infrastructure (e.g., a greenfield city as compared to a more mature city) and its climate, demographics, and topology can impose significant confounding effects.

Industrial Ecology

Industrial ecology can be defined as a multidisciplinary system-level study focusing on the interconnections between the industry, economics, and the natural environment. Industrial ecology utilizes a suite of different tools to analyze these interdependencies. Among these tools are life cycle assessment and material flow analysis, along with designing and manufacturing for the environment and ecological efficiency within the industry. The waste or by-products of one industry might be a resource for another industry, and if the two industries are located close enough for logistical viability, then the waste/by-product can be utilized by the other industry. For example, a cement manufacturer located near a power production facility may be able to use residual fly-ash from the power plant for its cement mix. And if a drywall production facility is also in the vicinity, it might be able to use the $CaSO_4$ from the cement plant as its raw material. Thus the net waste generation from these industries is reduced and their proximity saves significant fuel from the reduced need for transportation. This multitude of tools used in an industrial ecology assessment allows an industry or city to look at various designs and see how they affect inputs, outputs, and the overall effect on the economy.

Urban Sustainability

Urban sustainability is a systems-level holistic analysis of the sustainability of an urban system, particularly in regard to its infrastructure. Urban infrastructure is an intricate network of six major components: (1) private residences, (2) commercial establishments (including churches, schools, etc.), (3) water and wastewater, (4) energy, (5) transportation, and (6) land use. Urban sustainability also includes socioeconomic impacts and the policy drivers that cause the emergent properties of urban systems. With the demand for basic infrastructure growing with population, cities need to plan their infrastructures accordingly. Traditionally, urban areas were built with the "big-pipe concept," where the natural ecology was replaced with *hardscape* to provide for the urban infrastructure. *Nature* was restricted to curbside trees, and manicured parks and lawns filled with nonnative plants which require significantly more water and nutrients to thrive than the indigenous varieties. More recently, however, the importance of ecosystem services and preservation of natural ecology has been realized and natural alternatives, such as blue-belts for stormwater management, are increasingly being used in place of hardscapes. With this method, models are being developed to evaluate different options and to determine what social and economic decisions are needed to make them happen.

Current Infrastructure

Although current infrastructure may not be optimal, a large amount of capital has been invested in it and people still depend on it. One option for increasing sustainability is to develop a hybrid system of centralized and decentralized infrastructure, which increases redundancy without increasing the amount of requisite resources. Future planning also should guide how systems interact, and plan accordingly to save resources. Such interactions will now be described.

Water and Energy Nexus

Potable drinking water treatment provides clean drinking water, and wastewater treatment sanitizes sewage. Both use a great deal of energy in acquisition, treatment, and distribution. In 2000, the United States used more than 50 billion kWh of energy to attain, treat, and distribute drinking water and wastewater [10]. This is a huge demand for energy that is expected to continue to grow through 2050. The Electric Power Research Institute's (EPRI's) report on *Water and Sustainability* expects that by the year 2050, this number will reach over 75 billion kWh (Fig. 8.1). Already, water accounts for about 4% of the total energy sold in the United States. In California, it represents 18% of energy needs. And as water demand increases and good quality raw water becomes more difficult to find, these shares are likely to rise as advanced treatment technologies for reclaiming water or desalinating water are much more energy intensive. With this in mind, when a city is considering their water infrastructure, it also may want to keep in mind the amount of energy needed for various treatments for water and wastewater.

French Nuclear Power

In 2003, France experienced what was then their hottest summer on record [15]. The higher temperatures increased the demand for air-conditioning and refrigeration, which translated into an increased demand for electricity. In turn, increased energy production created more waste heat, which required more water for cooling purposes. Though France had plenty of capacity to produce electricity – the nation obtains ~80% of its electricity from nuclear power – the heat wave and drought limited the amount of water available for operation of the nuclear power plants, and the country was forced to turn off or reduce production at 17 of its nuclear reactors. As a result, France could no longer export electricity, which had been sold at €95 per MW-h to other EU countries, but needed instead to import electricity at a cost of ~€1,000 per MW-h.

Water can be treated using different methods, and with methodology differences there also are differences in energy dependency. Surface water tends to be cleanest, and as such requires the least amount of energy to collect and treat (Table 8.1). Surface water is not available in all areas though. Groundwater requires slightly more energy to treat and seawater desalination can use up to 75 times the amount of energy as surface water.

For treating wastewater, methods include a trickling filter, activated sludge, advanced treatment without nitrification, and advanced treatment with nitrification. The energy demand, shown in Table 8.2, is lowest for the trickling filter and highest for advanced treatment with nitrification. The simplest treatments consume the least

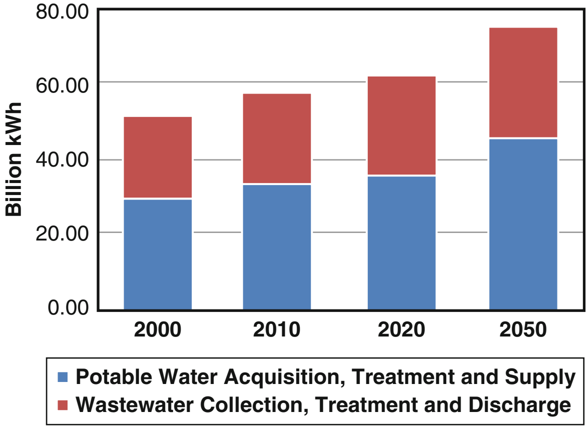


Fig. 8.1 Energy needed for drinking water and wastewater processes in the United States with data from the year 2000 and predictions of use until 2050 [10]

Table 8.1 National average energy demand by various water treatment systems [10, 11]

Water treatment and collection	kWh/MGal
Surface water treatment [11]	1,422
Groundwater treatment [10]	1,824
Brackish groundwater desalination [11]	3,900–9,750
Seawater desalination [11]	9,780–16,500

Table 8.2 National average energy demand by various wastewater treatment systems [10]

Wastewater treatment and collection	kWh/MGal
Trickling filter	955
Activated sludge	1,322
Advanced treatment without nitrification	1,541
Advanced treatment with nitrification	1,911

amount of energy, but they may not always be the most viable option given the quality of the water being treated and the requirements for the processed water. The gap in energy demand for the various approaches is much smaller in the case of wastewater than it is for water treatment.

Finally, power is also needed to distribute water. Logically, the farther that water needs to travel and the more difficult the water is to access, the more the energy that will be required to move it. Distributing water from lakes and rivers is the least energy intensive. It requires about 1,400 kWh/MGal to deliver [12]. Not all cities have lakes and rivers available to tap, however. For them, groundwater is more difficult to attain and requires slightly more energy. Lastly, discharging wastewater requires between 2,350 and 3,300 kWh/MGal on average.

The converse of energy being needed to provide, treat, and distribute water is that water is needed to produce, convert, and store energy. Water use in energy production varies depending on the source of energy. In the case of thermoelectric power generation, water is required for cooling purposes, while in case of

Table 8.3 The evaporative loss of water by different energy sources in the United States [14]

Energy source	Gal/kWh (evaporative loss)
Hydro	18.27
Nuclear	0.62
Coal	0.49
Oil	0.43
PV solar	0.030
Wind	0.001

hydroelectricity, water is used as the source of power. Water is also required for petroleum fuel processing, the primary energy source for transportation. Thus all forms of energy require water, which varies in the amount and purpose of its use depending on the energy source. Thermoelectric power accounts for 39% of freshwater withdrawals and 52% of our fresh surface water withdrawals [13].

The consumptive use of water for power generation is from evaporative losses. Every day thermoelectric power loses an average of 3.3 billion gallons of water to evaporation [13]. As one may suspect, certain kinds of power generation consume more water than others (Table 8.3). Accounting for the amount of energy produced and the water loss associated with each source, approximately 2 gal of water per kilowatt hour is lost to evaporation in the United States. Hydropower has an evaporative loss of 18.27 gal per kilowatt hour, which is more than 35 times the evaporative loss of water from coal-based thermal power. This implies that hydropower is feasible only in areas with an abundance of water. In contrast, photovoltaics and wind consume much less water.

Example: Water and Energy Demand: A Tale of Two Cities

Atlanta and Phoenix are two cities with rapidly growing populations. As such, the demand on water and energy are rapidly growing. Being that they are in different regions, they have different demands for water. Table 8.4 describes how these cities are very different in terms of demand. For example, Atlanta uses more water indoors, but Phoenix uses a significant amount more outdoors. With long commutes and poor public transportation, Atlanta uses significantly more fuel per person per day than Phoenix. Some of the more important differences are due largely to Phoenix being a city in an arid region, very hot and dry, whereas Atlanta is more humid and wet generally. The water consumption for electricity production in Phoenix is more than four times that of Georgia. The electricity consumption for water supply and treatment also is around five times more in Phoenix than Georgia. With it being considerably more difficult to get water to Phoenix, these numbers are bound to become higher. The dependence of water on energy and energy on water in Phoenix are even greater than in Atlanta. Yet Atlanta has experienced a great deal of turmoil with its water resources, as described in the previous paragraph. So a strain on the Colorado River is subject to cause more damage, all things being the same. This table also shows that cities are not the same. No solution is right for all cities.

Table 8.4 The relationship between water use and electricity use for the cities of Phoenix and Atlanta

		The City of Phoenix		The City of Atlanta	
Residential water demand	Indoor (gpcd)	48[a]	1999 data in Chap. 4 of The Water Environment of Cities [37]	71	2001 data in The World's Water 2008–2009: The Biennial Report on Freshwater Resources
	Outdoor (gpcd)	110[a]		20	
Power use	Residential electricity, kWh/person-day	36	2005 data [38]	41	2005 data Brown et al. (2008)
	Fuel, kWh/person-day	5.5		12.3	
Water consumption for electricity production	gal/kWh	7.85 (Arizona)	National Renewable Energy Laboratory (2003)	1.65 (Georgia)	Torcellini et al. (2003)
Electricity consumption for water supply and treatment	Water, kWh/MG	8,600	[39] Conveyance, 4600 Pumping, 2600 Water treatment, 100 Water distribution, 1300	1,700[b]	City of Atlanta Watershed Management, [13, 36]
	Wastewater, kWh/MG	10,700	[39] Wastewater collection and treatment, 1500 Reclaimed water, 9200	1,830[b]	

These data demonstrate the difference in use for the two different regions. Information of this sort must be considered when making energy and water plans for each city

[a]The numbers are modified assuming four people for one household

[b]The numbers are estimated based on the water and wastewater production of the City of Atlanta, the electricity use of the Atlanta Watershed Management Department (Thomas 2007), and the electricity demand for water supply and wastewater treatment of the South Atlantic Region (DOE [13])

Beyond the Water and Energy Nexus

While water and energy are inherently connected, there are other connections that are equally important in the context of urban infrastructure (Fig. 8.2). Transportation needs energy to fuel vehicles, and the amount of energy available affects modes of transportation. Land use affects the amount of transportation activity in an area, and transportation is needed to made land accessible. The availability of water affects how land is used, and the way land is used affects the demand on water and the ways water can be treated. Likewise, the availability of energy affects land and water use, and the way the land is used affects the energy demands and the kind of energy that can be created. Additionally, water is also used for extracting fuels and growing biofuels, which affects the transportation sector.

Energy for Transportation

Energy is needed to power a variety of transport vehicles including airplanes, trains, boats, trucks, and automobiles. The fuel used in these vehicles may be equally diverse and may include gasoline, diesel (both petro and bio based), ethanol, methanol, natural gas, electricity, hydrogen, solar, and even coal and wood (though these latter two are nearly negligible in the modern vehicle mix). The latest trend is to create hybrid vehicles that can utilize two or more fuel sources (e.g., gasoline and electricity). As of 2009, the transportation sector accounts for ~28% of the of total

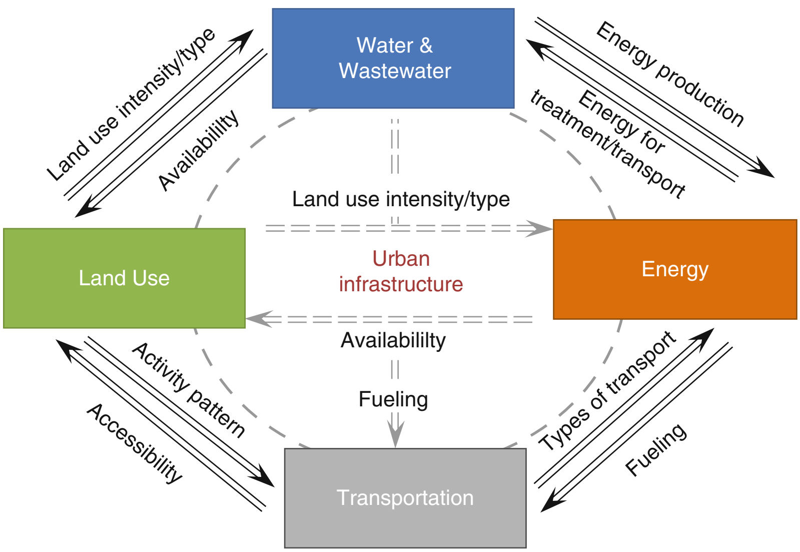


Fig. 8.2 Water, energy, transportation, and land-use systems are interconnected in urban regions

energy consumption in the United States and 72% of the nation's petroleum consumption [16]. Transportation also accounted for 3% of natural gas consumption and 12% of renewable energy use, mostly in the form of ethanol. Given these significant shares, the effect of transportation on energy needs to be considered when planning cities or city improvements.

Transportation, Land Use, and Energy

As the need for mobility increases, improving existing vehicle efficiency will lead to marginal reductions in the environmental impacts of transportation. Greater improvements, however, may be possible if switching to other modes of transportation is considered. In a 2007 study of plug-in hybrid electric vehicles, the Pacific Northwest National Lab [6] found that the current US electric power infrastructure could support the energy needs of 43–73% of the current light-duty vehicle fleet – the lower range resulting from the limiting of vehicle charging only to the 6 PM to 6 AM period. The study further estimated that if 73% of the US fleet was converted to electric vehicles, the United States would no longer need to import oil, and greenhouse emissions could be reduced by 27% (even if all electricity were generated by coal-fired power plants). While such broad-scale analyses are informative, it is important to note that complex local relationships underlie these bigger developments.

Bras recently completed an assessment of the energy and carbon dioxide emissions from different modes of transportation in Atlanta. Many kinds of vehicles and fuels were included in the study: conventional gasoline, diesel, compressed natural gas (CNG), ethanol 85 flexible-fuel vehicles (E85 FFV), spark-ignition (SI) gasoline hybrid electric vehicle (HEV), diesel HEV, SI plug-in hybrid electric vehicle (PHEV), diesel PHEV, electric vehicle, diesel vehicle, MARTA Clean Diesel bus, MARTA CNG bus, and MARTA rail. (MARTA is the Metropolitan Atlanta Rapid Transit Authority, which is the primary form of public transportation in Atlanta.) All of these transportation methods were evaluated on a Well-To-PUMP (WTP) and Pump-To-Wheels (PTW) basis for energy use and carbon dioxide emissions (see Figs. 8.3 and 8.4). Due to low ridership, MARTA's buses and rail are among the worst for both carbon dioxide emissions per passenger distance and for energy use per passenger distance. Increasing ridership would greatly improve these metrics. Other results suggest that electric vehicles do not fare much better than conventional gasoline and diesel. This is due, in part, to Georgia's dependence on older inefficient coal-fired power plants for energy. Overall, plug-in hybrid electric vehicles used the least energy and emitted the least carbon dioxide per passenger distance.

The implications of the effect of ridership on energy use and carbon dioxide emissions from various transportation modes in Atlanta suggest that other variables beyond just vehicles and fuel are also important. Planning and developing cities for growth with compact land use and transportation could significantly improve their sustainability and lower their dependence on energy. The way land is used affects the modes of transportation available and their efficiencies. For example, a compact

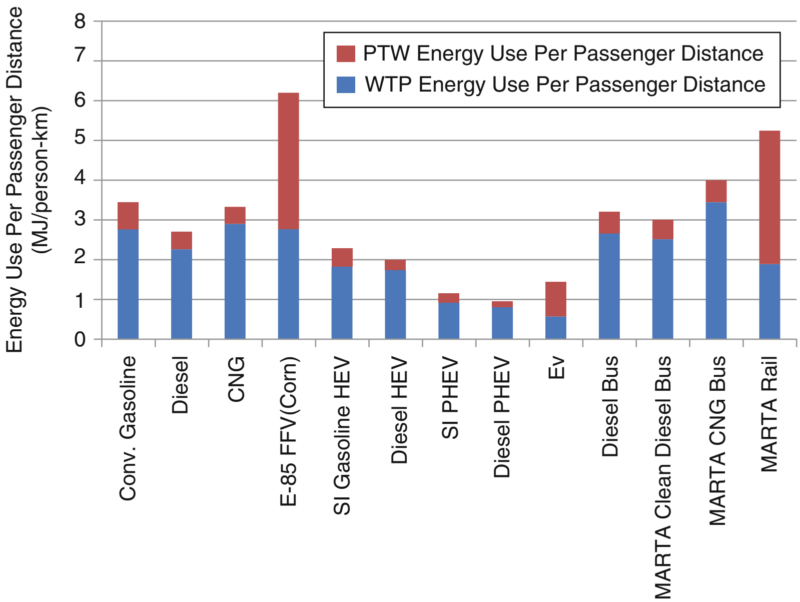


Fig. 8.3 The energy use per passenger distance for various transportation modes in Atlanta, GA

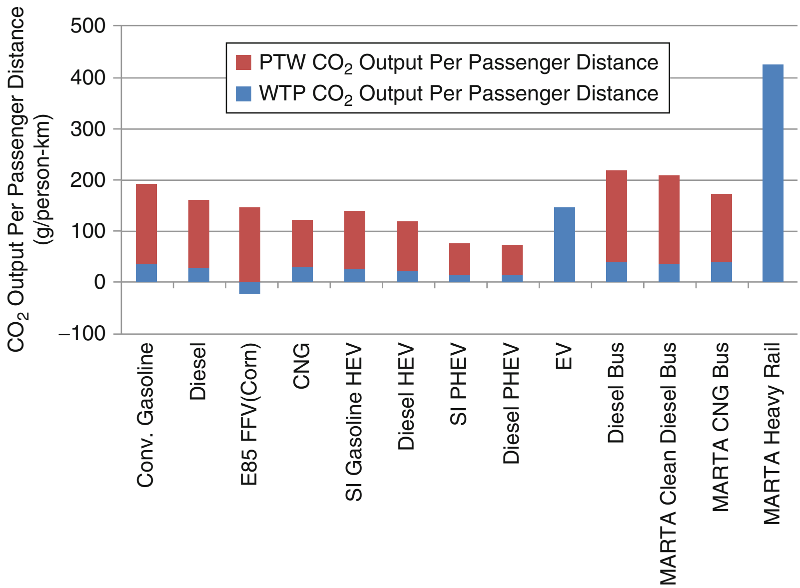


Fig. 8.4 Carbon dioxide emissions per passenger distance for various transportation modes in Atlanta, GA

Table 8.5 The dependence of various transportation fuels on water

Unit: Gal/kWh	Low	High	
Coal [13]	0.007	0.027	Mining+washing
Petroleum/oil [13]	0.03	0.076	Extraction+refining
Natural gas [13]	0.01	0.01	Extraction+processing
Corn-ethanol [17]	1.26	19	Assuming 15% irrigation for USA
Cellulosic ethanol [17]	0.13	0.431	No irrigation
Cellulosic ethanol [17]	16	19	Irrigation
Soy-biodiesel [17]	0.392	8.98	Assuming 4% irrigation for USA
Algae biodiesel [17]	0.839	1.762	Enclosed
Algae biodiesel [17]	0.895	18.351	Open

city favors walking, heavy rail, and other modes of efficient public transportation. New York City is a good example of this kind of city, where parking fees, gas expenses, and traffic lead the majority of the population to walk, take the subway, or ride the bus. An opposing example might be Atlanta, where the city is not compact enough to offer many people the option to walk or use public transportation.

Water for Transportation

Along with energy and land use, water is also intertwined with transportation. Department of Energy data [13], along with data from Harto's LCA of low carbon fuels [17], shows that oil consumes between 0.03 and 0.08 gal of water per kilowatt hour of energy [13] (see Table 8.5). Natural gas production uses a similar amount. Water needed to produce biodiesel from irrigated soy, though, is in the range of 0.39–9 gal of water per kilowatt hour. Corn-ethanol needs up to 19 gal of water per kilowatt hour, or ~500 times more than that for oil. From another perspective, Webber [12] found that a traditional gasoline car consumes around 7–14 gal of water per 100 miles traveled, PHEVs consume ~24 gal per 100 miles, and ethanol fueled vehicles require 130–6,200 gal per 100 miles.

The Compounding Power of Density

Urban density reaps a great many sustainable benefits. Public transportation is more accessible and commuting distances are generally shorter. Compact living also means that buildings can be closer to the infrastructures that provide them water and energy, which means less energy and materials are needed for distribution. It is also often the case that the more complex power and water networks that serve dense urban areas have built in redundancies that can compensate for component failures within the system. Finally, density affords other cross-pollinating opportunities such as combined heat and power, and low-impact development water infrastructure that also provides green space for recreation.

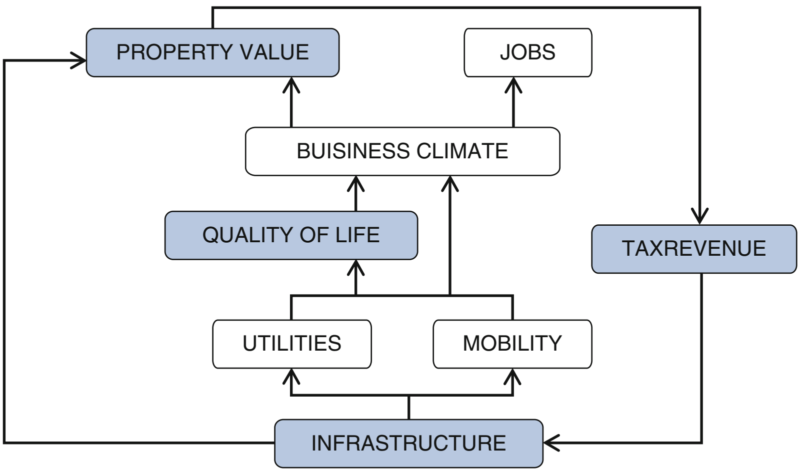


Fig. 8.5 The relationship between improved infrastructure and an improved socioeconomic environment

Jobs, Quality of Life, and Tax Revenue

The nexus of infrastructure extends beyond the interconnection of the physical, functional, and environmental constituent pieces. It also has implications for a place's social and economic well-being. Consider again, for example, the benefits of compact urban design. Land consumed by large private residential lots cannot be used by the collective community. Small private lots, on the other hand, preserve the opportunity to leave larger tracts available for recreation, wildlife habitat, and other amenities that are not possible when the land is fragmented. These public conveniences and desired attributes improve the quality of life for everyone, create a more favorable, stable, and job-producing business climate, and raise property values. And when the resultant increase in tax revenues is reinvested in the infrastructure, an engine of prosperity is created (see Fig. 8.5).

Steps Toward a More Sustainable Future

Water

Rain water is a source of clean water that does not need much treatment. However, most cities currently do not handle this resource efficiently. In most cases, stormwater becomes contaminated when it falls onto urban or agricultural surfaces, or is shunted into the wastewater system. Collection and treatment of stormwater using low-impact development (LID) techniques offers a myriad of benefits. The first step is to separate the collection of stormwater from wastewater.

One immediate benefit is that with less water to be treated, less energy is needed in the water treatment process. Reduced flow into the wastewater stream also reduces the risk of sewage overflow into surface waters. The stormwater that is collected can be used to create green spaces, to flush toilets, for cooling, or for fire fighting. Below is a sample of LID techniques that can be used.

Vancouver

The City of Vancouver was concerned about the stormwater and sewage that was being discharged into its salmon-bearing rivers [18]. The city considered traditional separation and decentralized treatment, but after discovering that putting in a centralized stormwater treatment facility would cost the city an estimated $4 billion, it decided to look into different options. One approach that employed low-impact development and decentralized treatment satisfied the water treatment needs while also creating green space which increased property values and led to an estimated increase of $400 million in tax revenue. It also resolved the environmental problem for their salmon-bearing rivers, improved conditions for other wildlife, and reduced the urban heat-island effect.

Best Management Practices for Pollution Control

Best Management Practices (BMPs) are techniques used in controlling water pollution and the flow of water. They are put in place to control pesticides, herbicides, nutrients, other existing pollutants, and emerging contaminants like pharmaceuticals and personal care products from moving from the land to the water. Some of these techniques may simply reduce the amount of toxins used in a process or pesticides used for farming. Some structural techniques include detention basins, which are used to prevent flooding in storms, and pervious pavement, which allows water to flow through its pores while holding a number of pollutants in the soil. These techniques help manage the flow of stormwater so that wastewater systems are less likely to be overwhelmed. They often rely on natural techniques, such as bioremediation or wet land treatment, to clean the water and are often less expensive and less energy intensive alternatives.

New York

The Safe Drinking Water Act required New York City to build new water filtration plants at a cost of ~$8 billion. Balking at the cost, the city instead acquired undeveloped lands to buffer the watershed, initiated a host of Best Management Practices (BMPs), worked with the farming community to develop a Whole Farm Plan to reduce runoff pollution, used LID techniques to reduce stormwater flow, and made a few upgrades to existing sewer and septic systems in the region. In the end, these actions, in lieu of the $8 billion cost of new filtration plants, enhanced the economic productivity of the land from recreation, farming, and the protection of the watershed from runoff [19].

Green Roofs

Green roofs are roofs that are partially or wholly covered with vegetation. They increase urban green space, reduce stormwater runoff, sequester carbon dioxide directly, and reduce building energy consumption. They can be added to buildings in two ways, intensive or extensive. An intensive roof is normally between 8 and 12 in. thick and weighs 80–120 lb per square foot [20]. Extensive roofs are thinner and much lighter (10–50 lb per square foot). Intensive roofs are often built as gardens, but must be well supported due to the increased weight. Extensive roofs are not necessarily meant to be visited, but may be used for some of the same benefits, but at a lower cost.

Indigenous Plants

Plants that are native to a region require less water, fertilizers, and pesticides than exotic plants. Indigenous plants have adapted to local conditions. Less effort is needed to maintain these plants, and they live longer than other plants would in their environment. Alternatively, plants with superior carbon sequestration qualities like yellow poplar and American sweet gums more effectively reduce the carbon footprint of a city relative to slower growing hardwood trees.

Pervious Pavement

Pervious pavement allows water to pass through the pavement for groundwater recharge and thereby decreases the amount of rainfall that enters the wastewater system. Pervious pavement is ideal for large, low traffic uses like parking lots, driveways, bike paths, and sidewalks. Not only does pervious pavement reduce the load of stormwater on wastewater treatment systems, but it also reduces nutrient and metal loads from runoff (by 80% and 90%, respectively) [21].

LID techniques should be accessed city by city and based on a cost-to-benefit analysis, as not all techniques are proper for each city circumstance. But while most LID techniques are beneficial even within traditional centralized water systems, decentralized systems may offer additional benefits. With conveyance and distribution responsible for 80% of the energy demand in the water sector [10], decentralized systems can offer significant savings. In addition, due to the lower residence time of the water in the distribution system, the final water quality at the tap is less compromised. Decentralized systems also add resilience to the system due to higher redundancies than in centralized systems. That is, if a centralized system fails, all the customers that it serves are at risk of being disconnected from their water supply. When a decentralized system fails, another nearby station can supply the water needed until the damaged plant is fixed.

While newly developing areas may implement decentralized water systems, other cities with existing centralized water treatment systems should not look to totally disassemble their infrastructure. Instead they should consider developing a hybrid centralized/decentralized model. This might be as simple as adding a decentralized plant in a quickly growing area instead of expanding the centralized plant. And because LID techniques such as rainwater harvesting and low flow toilets reduce the output needed from a water treatment plant, LID techniques and decentralization simultaneously work to enable and enhance each other.

Energy

Fossil fuels are a limited resource. As such, their use needs to be judicious and efficient. Improving the efficiency of vehicles, lighting, appliances, electronics, heating, ventilation, and cooling is one strategy. Another strategy may be redesigning the energy system by distributing power and incorporating renewables, and truly integrating multiple resource planning. Below are described a sample of opportunities.

Combined Heat and Power

A large amount of energy is lost in creating electric power; only about 30% of the energy input results in electricity delivered to the customer [23]. Seventy percent of the energy is lost in converting the primary fuel into electricity and distributing through the power grid. For that same amount of input energy, a combined heat and power system could utilize ~85% of the input energy (see Fig. 8.6). Combined heat and power has the potential to provide the United States 20% of the electricity by 2030, which could reduce an estimated 0.2 gigatons of carbon annually. This system also emits, on average, 1/10th of the nitrogen oxides (NO_x) per kWh as compared to the average grid electricity [24]. Helsinki Energy in Finland used combined heat and power, and has experienced great results [24]. Sulfur dioxide emissions from district heating were reduced around 90% from 1980 to 2004. This scheme also saved Finland six million tons of carbon emissions in 2004. Using less energy means fewer greenhouse gases are created, and with the climate changing so quickly, emission reduction is needed. Systems like these generate electricity and use the waste heat for a variety of processes like chemical manufacturing, heating buildings, or producing hot water, and thereby eliminate or reduce the energy and consequent environmental impacts needed for those demands [23, 24].

Energy Efficient Products

In most existing applications, simply upgrading or modernizing energy demanding products will result in improved efficiencies and higher performance. Even low-end refrigerators produced today may be several times more efficient than refrigerators

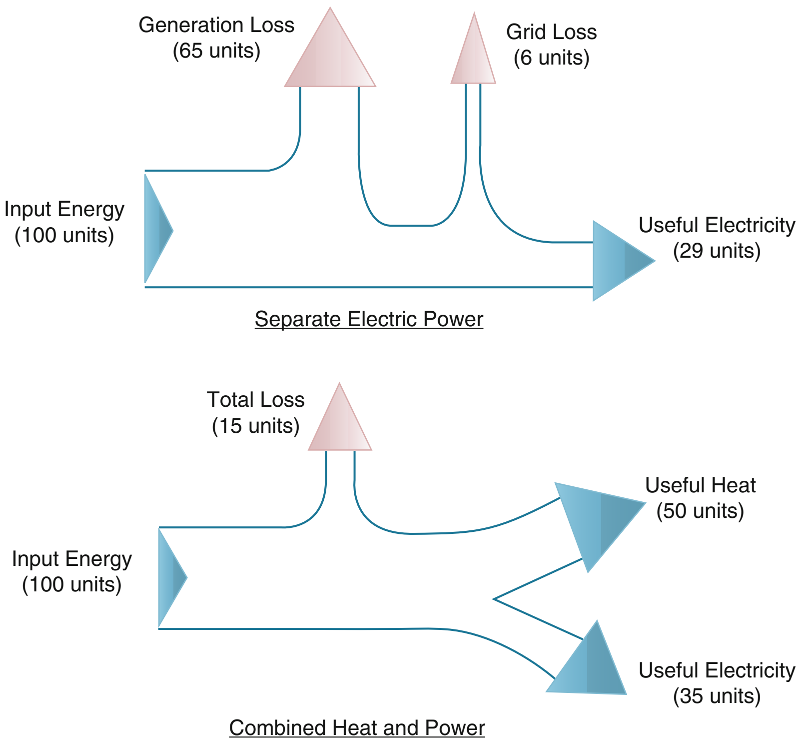


Fig. 8.6 Utilization of energy for separate electric power and combined heat and power. The amount of energy lost is much higher in the separate system due to the recycling of heat to make more energy (Amended from [22])

produced 20, 30, and 40 years ago, while also providing more features and functionality along with a relatively short payback period. When choosing new or replacement products, however, certified Energy Star products use 20–30% less energy than the federal standards require [25]. Eligible products include appliances, electronics, heating and cooling systems, lighting, fans, plumbing fixtures, and building products like insulation and roofing.

Photovoltaics and Other Renewable Energy Sources

Every day the sun provides more than enough energy to meet all the demands of humans and nature. But while nature has evolved to efficiently harvest this free energy, human made systems are only now becoming cost-effective (see Fig. 8.7). Comparing photovoltaic power generation to coal generation, Table 8.6 shows for each source the ratio of energy output to energy invested water use, land use, cost of power, and jobs. While the lower overnight cost of power still favors coal, the other attributes indicate that PV is already a competitive alternative. With costs

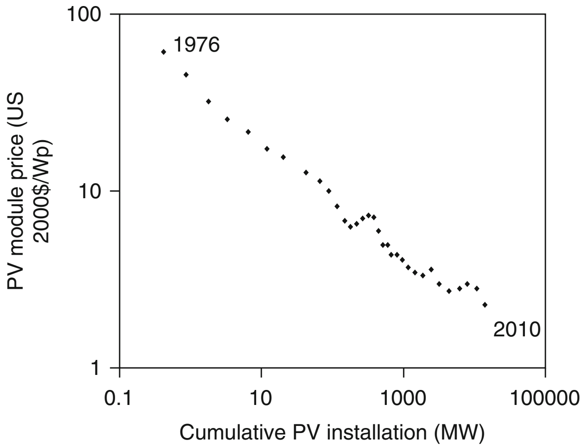


Fig. 8.7 Price of a PV module per Watt peak (constant year 2000 US dollars) as a function of cumulative installation of PV in megawatts for the period 1976–2010 [27]

Table 8.6 A comparison of power generation from photovoltaic and coal energy sources

Energy Source	Photovoltaic	Coal
$\frac{\text{Energy output}}{\text{Energy invested}}$ [28]	9.0	5.0
Water use [29]	0.001 Gal/kWh	0.49 Gal/kWh
Land use	0.51 kWh/acre (RET Screen Simulation)	690 kWh/acre [30–33]
Overnight cost [34]	$4.75/kWh	$2.84/kWh
Total job-years/GW h (avg) [32]	0.87	0.11

continuing to drop, however, PV could soon become the preferred power source with coal becoming the less attractive alternative.

Wind, geothermal, biomass, and hydroelectricity are some of the other renewable energies that are growing in importance. For example, a recent working report suggested that there is an unrealized potential of 29,400 MW of hydroelectricity that could be developed in the United States [26]. One problem with renewable resources, though, is their inherent intermittency. In order for many renewables to become practical, large-scale inexpensive energy storage methods need to be developed. These methods may include various types or combinations of electrochemical batteries, flywheels, compressed air, superconductive magnetic storage, and the oldest, the least capacity-constrained and most popular when available, pumped hydro-storage.

Decentralizing Distribution

Apart from the manner in which power is generated, system resiliency can be increased by changing how the power is distributed. The smaller scales inherent to renewable generators, such as PV, mean that these generators can more readily be

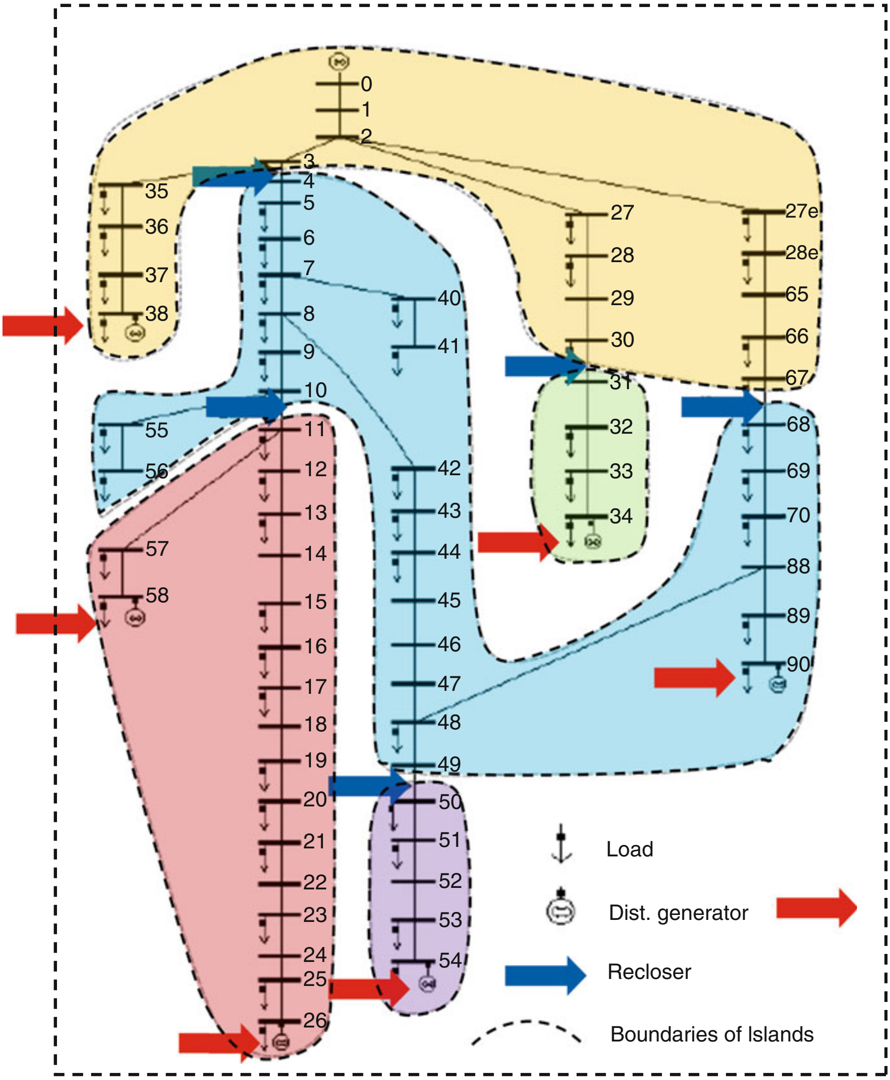


Fig. 8.8 A depiction of an islanded distribution network. This system is split into multiple zones with balanced distributed generation and loads (as shown by the *dotted lines* and *multiple colors*). There are multiple distributed generators, and each island has a recloser at the boundaries with other zones. This allows the islands to cut off from each other in case of a disturbance, keeping the larger portion of the network supplied with energy. Once the problem is fixed, the islanded system can then automatically be reconnected to the grid (transmission network)

located in various locations across the distribution feeder. Microgrids can be created by separating the distribution feeders into zones of balanced generation and load can by placing reclosers at the zone boundaries (reclosers are similar to circuit breakers, but do not have the capability to interrupt the fault current; see Fig. 8.8, e.g.).

In the case of a feeder separated from one of its supply substations by a fault location, such a network may allow the feeder still to be energized and supplied by other generators while the faults are being mitigated. That would improve reliability as measured by indices such as SAIFI and SAIDI (system average interruption frequency and duration index), CAIFI and CAIDI (customer average interruption frequency and duration index), and ASUI and ASAI (average service (un)availability index). Improvements in such indices (or composite indices) usually mean better customer satisfaction and diminished losses associated with repetitive outages, that is, increased resiliency.

Example: Distributed Renewable PV Generation

Distributed generation consists of small-scale and decentralized electric energy systems. Capacities vary, typically in the range of several kW to hundreds of MW. Accurate and efficient system analysis algorithms are needed in order to analyze the impact of PV systems on various types of microgrids and distribution networks. The influence of uncertainties can be modeled via suitably optimized Monte Carlo techniques.

Commercial PV power industries started developing in the 1970s. In spite of a 70% reduction of the real price of PV modules over 40 years, energy from PV remains too expensive to compete with conventional sources. Political changes in the United States in the early 1980s ended substantial funding for solar energy research and, since the nation represented nearly 80% of the global market for solar energy at that time, virtually halted solar energy development around the world. In 2004, renewable energy sources accounted for 9.6% of the electricity generated in the United States and 18.6% worldwide. China was the leading nation by renewable generation capacity in 2008 (598 TW h of renewable energy produced that year). A total of 3,584 TW h of renewable energy was produced in the world in 2008, of that only 12 TW h was from solar photovoltaic generators while, for example, 16% (3,288 TW h) of world electric energy was produced from hydroelectric plants. However, PV has become one of the most rapidly growing energy generation technologies. PV module shipments have grown at an average annual rate of 40% since 1996, up from 13% in the previous decade. The potential growth may transform PV into a $100 billion industry [35].

On the technical side of PV proliferation, electric power utilities are not motivated to allow interconnections of customer-owned generators (such as many PV installations would be) to their distribution networks (mostly for operational reasons). Utilities tend to put nonutility generation under the extensive technical analysis. Conversely, the regulating authorities tend to act in favor of DG owners and support that the interconnection be as easy and transparent as possible.

The main objective of PV installation is to boost the energy savings. Figure 8.9 shows annual estimated monthly PV generation output of an assumed PV system in the Atlanta area in the United States. Figure 8.10

(continued)

Example (continued)

presents how the total load demand is decreased due to the PV generation with capacity ranging 10–40% of the annual peak load at the same feeder. The figure represents the system performance on the 244th day of the year. If the distributed generator (DG) is owned by the customer, the actual benefit is cost saving in the electric bill. If the DG is owned by the utility, the benefit is avoided energy production from the less desirable or more expensive sources and reduction in transmission and distribution losses. This benefit means energy saving in both cases.

The second impact of solar electricity generation is the ecological impact. The PV output energy savings provide the opportunity to create the avoided carbon footprint by not using the more ecologically impactful technologies (coal, natural gas, etc.). In addition to reducing the effective feeder load in the distribution networks where it is installed (thus also reducing the transmission and distribution losses), PV generation can also bring about CO_2 reduction. It can also cause water footprint reduction through avoided thermoelectric and hydroelectric generation, and fuel reduction, such as coal, petroleum, and natural gas in the thermal power generation as in Table 8.6. The example assumes that the PV system is optimally oriented to maximize energy production. (If shaving of peak load levels is the main objective, it is possible to orient the PV system more westward, thereby boosting the PV output at the peak load times.)

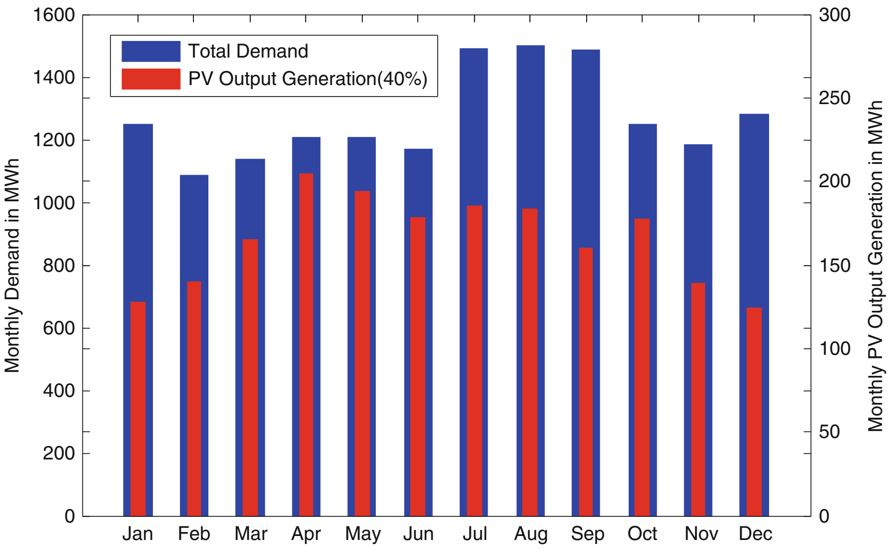


Fig. 8.9 Annual PV generation and load demand on a typical distribution feeder. It is assumed that the total PV capacity is equal to 40% of the peak load demand

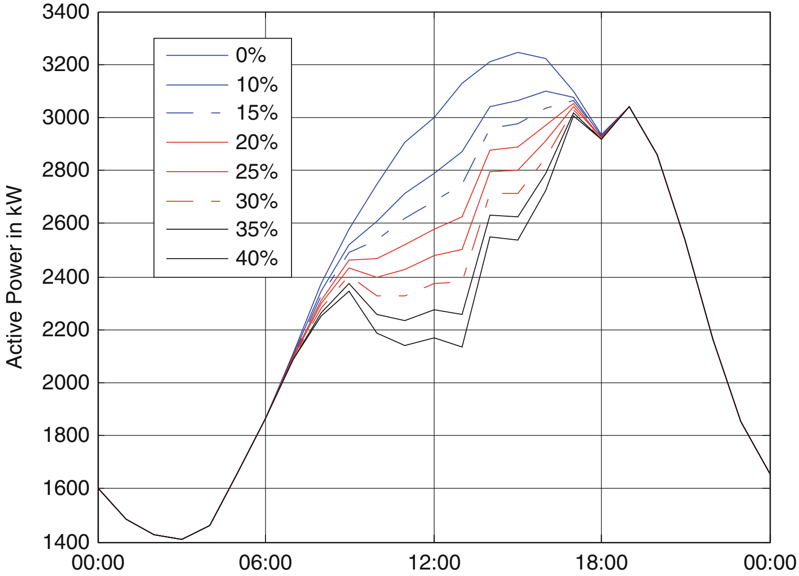


Fig. 8.10 The effect of PV generation on a typical day of the year (horizontal axis represents time of the day). Assumed PV capacity is 40% of the annual peak load

Understanding Aggregate Demand

A number of factors need to be considered in every city when making decisions to improve sustainability. Inputting all the data necessary to run a good model of a city is a massive undertaking, but the model could be a very useful tool.

For the modeling of Atlanta, Geographic Information System (GIS) tools were used to input infrastructure data. The What if?™ system was used to model Atlanta. This software was used to show the suitability of various infrastructures for an area. Figure 8.11 shows the suitability for eight different land-use types. As Atlanta continues to develop, this can be used as a tool to plan infrastructures for areas that are more suitable. Along with suitability factors, this program was used to predict the land use of Atlanta as it grows. Figure 8.12 shows Atlanta's use of land in 2010 and the prediction for land use in 2030, using the Business as Usual scenario. This scenario looks to grow the city in the traditional urban sprawl way, and the figure shows much of the land use going to residential use and employment centers expanding outward from the city center. Figure 8.13 offers a different comparison, this one of two different growth scenarios: Business as Usual and Compact Growth as predicted for 2030. This comparison shows the difference in how Atlanta can grow, with more compact living and more undeveloped area, or with continued urban sprawl.

Programs such as What if?™ and UrbanSim give a rough prediction of the future, but the scenarios in these programs are not easily edited by the user.

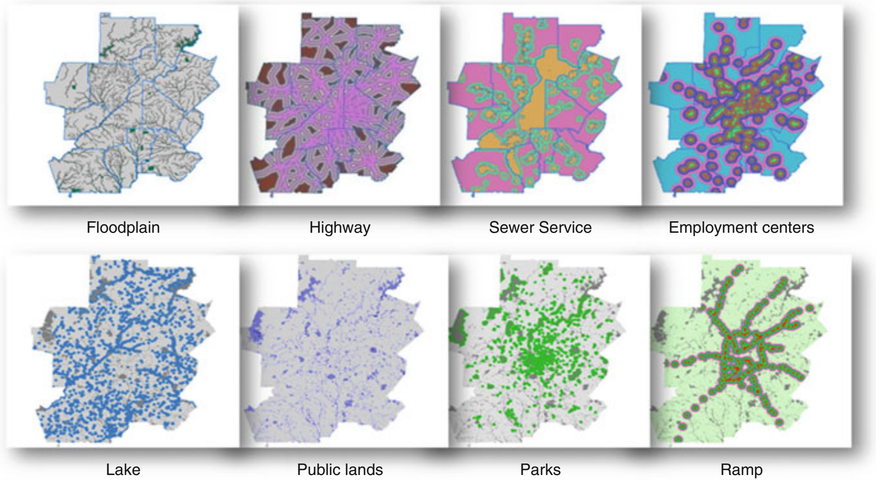


Fig. 8.11 The maps show the 13 county metropolitan Atlanta area. Based on the land, the program What if?™ developed the suitability for different kinds of infrastructure and land use

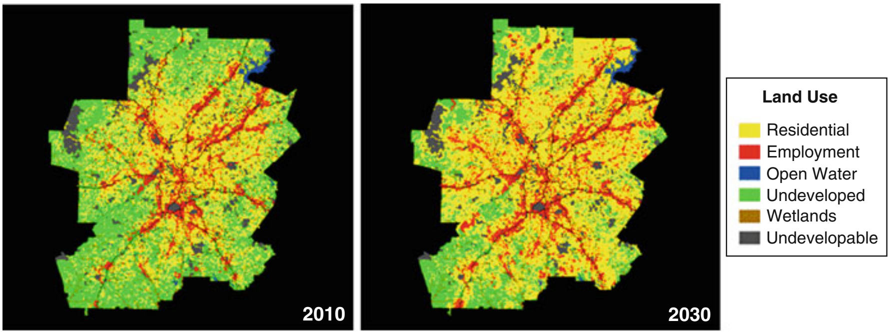


Fig. 8.12 The 13 county metropolitan Atlanta area's land use. This shows the prospective land use using the Business as Usual scenario from the What if?™ software. Employment centers and residential areas expand outward over the 20 years, leaving very little area undeveloped

To date, infrastructure planning has been an exercise in developing a few different scenarios that fit the general tendencies of the agents and groups of agents that the infrastructure intends to serve. This approach, though, fails to account for a number of factors that affect the decision making of agents. Looking beyond a set of scenarios, agent-based modeling creates equations for how people react to different constraints and opportunities. For example, surveys and behavioral analyses can be used to develop algorithms that describe how people react to policy decisions or to gauge consumer awareness. These reactions though are

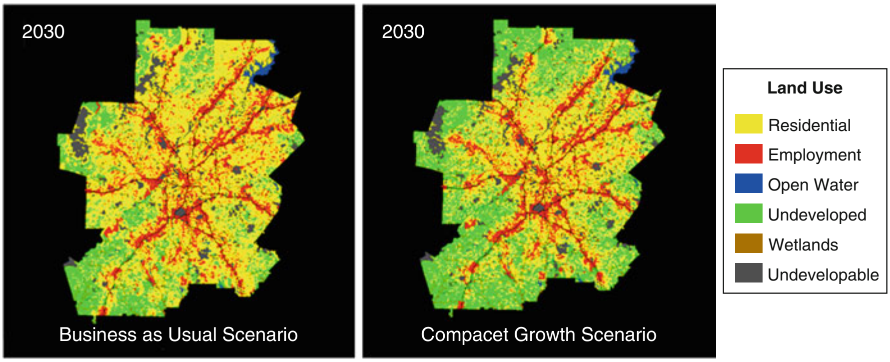


Fig. 8.13 The 13 county metropolitan Atlanta area's prospective land use in 2030. This is according to the simulation run with the What if?™ software. These show the comparison of development based on two different scenarios, Business as Usual and Compact Growth. Compact Growth shows that much more land is left undeveloped and residences remain near the city, whereas Business as Usual shows an increase in urban sprawl

tempered by the context of many other variables though such as economic feasibility, the state of current infrastructure, or the availability of technology. Modeling could provide a number of answers to questions concerning a city's sustainability. Some of the questions it could help address are as follows:

- What price are people willing to pay for renewable energies, and what kind of policies may be needed to encourage this choice?
- How can the transportation network be better planned in order to make public transportation efficient, and at what price will people pay to choose more sustainable forms of transportation?
- What incentives are needed for people to live in more compact spaces?
- How can consumption of nonrenewable resources be reduced?

Agent-based modeling, in combination with other modeling tools, is needed to predict the demand for urban infrastructure, how it should be built and designed, and what materials should be used.

Future Directions

For the future, there is a need to redesign our anthroposphere (the place where we live), so that it can exist within the means of nature: using only the renewable resources that nature can sustainably provide, while generating only wastes that nature can sustainably assimilate.

Future goals include:

- Monitor, model, visualize, and predict the emergent properties of urban infrastructure systems and their resilience to stressors.
- Understand the flow of resources and information as they move through the urban system with urban metabolism.
- Develop a pedagogy for the design of complex systems for sustainability within the context of urban systems.
- Integrate the human perspective into urban infrastructure so that socially sustainable policies and outcomes are produced.
- Research and develop sustainable alternative technologies for water treatment, and materials and energy production.

Acknowledgments The authors would like to thank Brook Byers Institute for Sustainable Systems, High Tower Chair, and Georgia Research Alliance for their financial supports.
Funding for this research was provided by the US NSF grant 0836046: EFRI – RESIN Project: Sustainable Infrastructures for Energy and Water Supply (SINEWS). Any opinions, findings, conclusions, or recommendations expressed in this paper are those of the authors and do not necessarily reflect the view of the supporting organizations.

Bibliography

Primary Literature

1. GreenBiz (2000) Why tackle the sustainability challenge? GreenBiz.com
2. Committee on Education (1987) Our common future, from one earth to one world. In: UN Documents: gathering a body of global agreements, UNO
3. Xu M, Crittenden J, Chen Y, Thomas V, Noonan D, Desroches R, Brown M, French S (2010) Gigaton problems need gigaton solutions. Environ Sci Technol 44:4037–4041
4. Toepfer K (2005) One planet many people. In: UNEP press release, 2005/27
5. UNEP (2009) Population division of the department of economic and social affairs of the UN Secretariat (2009). World population prospects: the 2009 revision and world urbanization prospects. United Nations Population Division, New York
6. Kintner-Meyer M (2007) Impacts assessment of plug-in hybrid electric vehicles on electric utilities and regional US power grids part 1: technical analysis. Pacific Northwest National Laboratory, Richland
7. Bruneau M, Reinhorn A (2007) Exploring the concept of seismic resilience for acute care facilities. Earthq Spectra 23:42–62
8. Carnegie Mellon University Green Design Institute (2008) Economic input-output life cycle assessment. http://www.eiolca.net
9. Ohio State University Process Systems Engineering Group (2009) Ecologically-based life cycle assessment. http://resilience.eng.ohio-state.edu/eco-lca/index.htm
10. Goldstein R, Smith W (2002) Water and sustainability (vol 4): U.S. electricity consumption for water supply and treatment – the next half century. EPRI Technical Report 1006787, EPRI, Palo Alto
11. Klein G, Krebs M, Hall V, O'Brien T, Blevins BB (2005) California's water-energy relationship. In: Integrated energy policy report proceeding (04-IEPR-01E). California Energy Commission, Sacramento

12. Webber M (2008) Catch-22: water vs. energy. Sci Am 18:34–41
13. US Department of Energy (2006) Energy demands on water resources. Report to Congress on the interdependencies of energy and water. US DOE, Washington, DC
14. Gipe P (1995) Wind energy comes of age. Wiley, New York
15. Kanter J (2007) Climate change puts energy into hot water. New York Times, 20 May 2007
16. US Energy Information Administration (2010) Annual energy review 2009. US Department of Energy, Washington, DC
17. Harto C, Meyers R, Williams E (2010) Life cycle water use of low-carbon transport fuels. Energy Policy 38:4933–4944
18. Engineering Services, City of Vancouver (2005) Crown street, sustainable streetscapes and fish habitat enhancement project. Engineering Services, City of Vancouver, Vancouver
19. USAID Water Team (2003) USAID water team case study in integrated water resources management. USAID, Washington, DC. http://www.usaid.gov/our_work/environment/water/case_studies_success.html
20. Culligan P (2011) Solving urbanization challenges by design – the science of green roofs. Columbia University, The Earth Institute, New York
21. Minnesota Stormwater Steering Committee (2008) The Minnesota stormwater manual: version 2. Minnesota Pollution Control Agency, St. Paul, pp 352–353
22. EPA (2011) WaterSense®: program accomplishments. http://www.epa.gov/WaterSense/about_us/program_accomplishments.html
23. Elliott RN, Spurr M (1999) Combined heat and power: capturing wasted energy. ACEEE, Washington, DC
24. UNEP (2005) Combined heat and power: clean and efficient energy production. United Nations Environmental Programme, Governing Council, http://www.unep.org/GC/GCSS-IX/Documents/FINLAND-combinedheatpower.pdf
25. US Energy Information Administration Database
26. Weise E (2008) The shape of lights to come? Not everyone's buying it. USA Today, 28 Feb 2008
27. Brown M, Gumerman E, Baek Y, Morris C, Wang Y (2010) Renewable energy in the south: a policy brief. Working paper
28. Pandit A, Jeong H, Crittenden JC, Xu M, Ariaratnam S, Begovic M, Bras B, Brown M, DesRoches R, French S, Georgakakos A, Karady G, Li K, Noonan D, Perrings C, Williams E (2010) Sustainable and resilient urban infrastructure design: a holistic approach. In: The 6th international conference on sustainable water environment, session 4.7: Infrastructure, Newark, DE
29. Gagnon L (2002) Life-cycle assessment of electricity generation options: the status of research in 2001. Energy Policy 30(14):1267–1278
30. Georgia Power (n.d.) Plant Branch. Retrieved from Georgia Power. www.georgiapower.com/about/pdf/Plant%20branch%20Brochure.pdf
31. Georgia Power (n.d.) Plant Branch. Retrieved from Georgia Power. www.georgiapower.com/about/pdf/Plant%20branch%20Brochure.pdf
32. Georgia Power (n.d.) Plant Robert W. Scherer. Retrieved 2010, from Georgia Power. www.georgiapower.com/about/pdf/Plant%20sherer%20Brochure.pdf
33. Georgia Power (n.d.). Plant Wansley. Retrieved from Georgia Power. www.georgiapower.com/about/pdf/Plant%20Wansley%20Brochure.pdf
34. US Energy Information Administration (2010) Updated capital cost estimates for electricity generation plants
35. Miroslav M, Begovic IK (2011) Distributed renewable PV generation in urban distribution networks. In: PSCE 2011, IEEE power systems conference and exposition, Phoenix
36. Borin S, Wang J, Thomas V (2009) City of Atlanta greenhouse gas emissions inventory. Report to the City of Atlanta, Atlanta
37. Westerhoff P, Crittenden J (2009) Urban infrastructure and use of mass balance models for water and salt. In: LA Baker, ed. The Water Environment of Cities. Boston, MA: Springer US, pp 49–68

38. Brown MA, Southworth F, Sarzynski A (2008) Shrinking the carbon footprint of metropolitan America. The Brookings Institution, Washington, DC
39. Scott C, Pasqualetti M, Hoover J, Garfin G, Varady R, Guhathakurta S (2009) Water and energy sustainability with rapid energy growth and climate change in the Arizona-Sonora border region. Report to the Arizona water institute (closed)

Books and Reviews

Agence France-Presse (2006) Heat wave claims lives in Europe, and hottest days are still to come. New York Times-Europe, 19 July 2006

US EPA Region 2 (2006) Report on the City of New York's progress in implementing the watershed protection program, and complying with the filtration avoidance determination. US EPA Region 2. New York City watershed team and New York State Department of Health Bureau of water supply protection. US EPA, Washington, DC

Tugend A (2008) If your appliances are avocado, they probably aren't green. New York Times, 12 May 2008

Klein G (2009) The water-energy-carbon footprint connection

Wei M, Patadia S, Kammen D (2010) Putting renewables and energy efficiency to work: how many jobs can clean energy industry generate in the US? Energy Policy 38(2):919–931

Bruno L (1931) Magic plates, tap sun for power. Pop Sci 118:41

Torcellini P, Long N, Judkoff R (2003) Consumptive water use for U.S. power production. NREL, Golden, p 5, Dec 2003

Annual Energy Review (2009) U.S. Energy Information Administration. US DOE, Washington, DC, p 230, Aug 2010

Lazard Ltd (2009) Levelized cost of energy analysis, version 3.0. Lazard, New Orleans, p 2, Feb 2009

Chapter 9
Sustainable Smart Grids, Emergence of a Policy Framework

Marilyn A. Brown and Shan Zhou

Glossary

Cost-benefit analysis	Cost-benefit analysis is an economic approach to policy evaluation. It measures the timeline of expected costs and benefits associated with policy implementation, discounting future values to produce a net present value. Cost-benefit ratios are also used to evaluate a policy relative to the status quo or an alternative policy formulation.
Demand response	Demand response is a means of reducing customer consumption of electricity in response to supply conditions. It is different from energy efficiency, which involves using less electricity to perform a particular task.
Distributed generation	Distributed generation involves the production of electricity from many small energy sources (including, for instance, natural gas turbines and solar photovoltaic panels). It is distinct from the prevailing generation of electricity at large centralized facilities.

This chapter was originally published as part of the Encyclopedia of Sustainability Science and Technology edited by Robert A. Meyers. DOI:10.1007/978-1-4419-0851-3.

M.A. Brown (✉) • S. Zhou
School of Public Policy, Georgia Institute of Technology,
685 Cherry Street, Atlanta, GA 30332-0345, USA
e-mail: marilyn.brown@pubpolicy.gatech.edu; shanzhou@gatech.edu; zhoushanbnu@gmail.com

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*,
DOI 10.1007/978-1-4614-5830-2_9,

Feed-in tariffs	Feed-in tariffs provide incentives for the generation of renewable electricity. Governments and utilities provide guaranteed purchase contracts for electricity generated from renewables; the particular tariffs may change over time to track the development of technology and cost reduction.
Natural monopoly	Natural monopolies occur when economies of scale reduce production costs, such that one firm can produce at lower costs than multiple firms. Many public goods are typically provided by natural monopolies, such as electricity, railway, and water.
Public good	A public good is a good that is non-excludable and non-rivalrous. It is costly to keep nonpayers from enjoying a public good, and one's consumption of a public good does not affect another's ability to consume the good. Natural defense and clean air are two examples of public goods.
Renewable electricity standard	Renewable electricity standard is a policy target that sets minimum requirement for electricity generated from renewable energy sources.
Renewable energy certificates	Renewable energy certificates are tradable energy commodities. One certificate often represents one megawatt-hour of electricity generated from renewable energy.
Time-of-use pricing	Time-of-use pricing refers to electricity prices, which change based on time of consumption, such as peak and off-peak periods.

Definitions of Smart-Grid Policies and Their Importance

A smart grid is an electricity network that can (1) cost-efficiently integrate a diverse set of generators, (2) enable consumers to play an active role in managing the demand for electricity, and (3) operate at high levels of power quality and system security [1]. Policies to promote smart grids include net metering tariffs and time-of-use pricing; interconnection and technology standards; subsidies, targets and goals; customer privacy protection laws; and rules governing the ownership of renewable energy credits (Fig. 9.1).

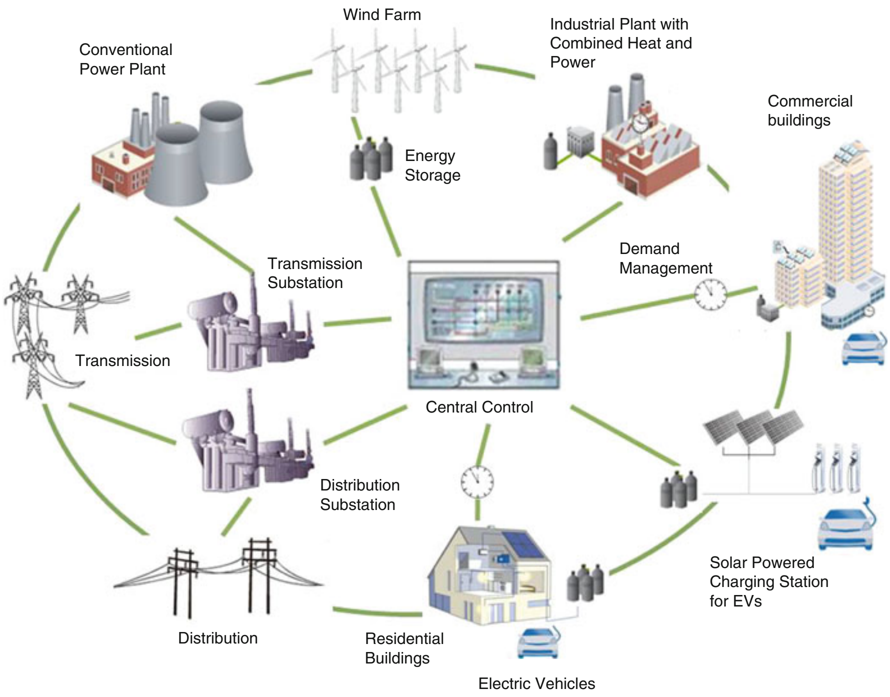


Fig. 9.1 Smart grid: a vision for the future

- Smart grids facilitate the connection and operation of generators of all sizes and technologies. Recent improvements in the cost-effectiveness of distributed generation (DG) have underscored the importance of this ability to interconnect utility-owned DG assets (such as wind and solar farms) as well as customer-owned DG (such as industrial cogeneration facilities and building-integrated photovoltaics). The ability to integrate low-carbon and sustainable energy resources is essential to reducing the environmental impact of electricity supply systems.
- Smart grids also enable consumers to play a part in optimizing the operation of the system by providing them with greater information and options for how they management their energy consumption. With the help of smart-grid technologies and demand response programs, consumers can be motivated to reduce their peak electricity consumption, thereby reducing capital spending for power generation, transmission, and distribution investments [2, 3]. Enduring concerns about oil security combined with recent advances in electric vehicles have created the hope that smart grids could help support the electrification of transportation.
- Through proactive grid management and automated response, smart grids can provide system security and reliability as well as the high levels of power quality needed for increasingly digital economies. The smart grid implementation

workshop held by the US Department of Energy (DOE) in 2008 emphasized the ability of smart grids to anticipate and respond to system disturbances in a self-healing manner and to operate resiliently against natural disasters and physical and cyber attack [2].

In sum, smart grids offer the potential to improve the efficiency and affordability of power delivery, mitigate environmental impacts, and reduce oil dependence while maintaining high levels of power system reliability and resilience [1, 4]. These numerous benefits include two critical positive externalities: climate change mitigation and energy security [137]. However, various obstacles inhibit smart grids from gaining rapid and widespread market share. Thus, with the recent introduction of smart-grid technologies has come the emergence of smart-grid policies, which are government interventions designed to protect the public's interest in affordable, dependable, and clean electric power by promoting the deployment of the smart grid.

Introduction

The electric power infrastructure in most industrialized nations has been designed to support a large, monopolistic, centrally controlled power system. Before 1990, the electricity system in most countries consisted of vertically integrated (generation, transmission, and distribution) monopolies that were highly regulated. The rationale for this system design was the assumption that electricity production is a natural monopoly, where a single firm can produce the total market output at a lower cost than a collection of competing firms. At the transmission stage, the case for natural monopoly and continued regulation remains relatively strong, but the natural monopoly rationale for electricity generation and distribution has been weakened by the introduction of distributed electricity resources and small-scale electricity producers. While local distribution and generation systems in many countries have recently benefited from the introduction of some elements of market competition, the prevailing utility monopoly continues to play a dominant role in the production and distribution of power and generally oppose consumer-owned DG. For this reason, and because of other impediments discussed later in this chapter, smart grids remain an emerging technology.

Vertically integrated power systems have also become increasingly vulnerable to power outages and interruptions. Large-scale blackouts caused by rising electricity peak demand, aging infrastructure, extreme weather conditions, and terrorist attacks produce significant economic and social costs. For the United States alone, power outages and interruptions cost Americans over $150 billion each year [4]. Outages are more frequent and are affecting an increasing number of people in recent years [4]. The 1987 blackout in Japan caused by high peak demand in the summer affected 2.8 million households [5]. The US–Canadian blackout of August 14, 2003 impacted 50 million people in eight US states and two Canadian provinces, with estimated total costs between $4 and $10 billion [6]. In 2006, 2.5 million customers experienced power outages after Hurricane Katrina hit the US Gulf Coast [7].

These events have stimulated growing public awareness of the need for grid modernization. Transitioning to a smart grid, however, will require implementation of policies to address barriers to smart-grid deployment and to regulate data access and equity concerns.

Technological breakthroughs often precipitate the parallel development of new policy frameworks. This has been the case in the medical profession with stem cell research and cloning, in transportation with the development of commercial space travel and intelligent transportation systems, and in the communications industry with the creation of the Internet and widespread utilization of smart phones. In all of these cases, as with the smart grid, policy frameworks must be created to ensure that the public's interests are protected. Thus, with the recent introduction of smart-grid technologies has come the emergence of new smart-grid policies.

This chapter begins by providing an overview of the barriers that hinder smart-grid deployment, the drivers that motivate it, and the policies that are commonly used to encourage smart-grid investments. Attention then turns to a review of experiences with smart-grid policies beginning with an analysis of US policies and an overview of US stakeholders. To characterize the smart-grid policy initiatives introduced by individual states and utilities, activities of four states are investigated: California, Georgia, New York, and Texas. This chapter also provides some insights into European Union smart-grid policies, with a special focus on Great Britain and Italy. To illustrate the smart-grid policies used in other hemispheres, we also describe policy initiatives in China, Korea, and Japan. This chapter ends with a brief discussion of future directions and conclusions.

Barriers to the Deployment of Smart Grids

Stakeholders worldwide have widely acknowledged the importance of grid modernization. Although many of the technologies needed for smart-grid development are available nowadays, widespread deployment of these technologies is still limited. Effective policies that facilitate the evolution of the electricity grid generally are those that address key barriers to the deployment of smart grids. This section provides a brief description of barriers that have been identified to date.

High Costs. Large upfront cost is one of the greatest challenges to the deployment of smart grids [8]. Like many other green technologies, deployment requires significant initial investment, yet the resulting benefits are not fully realized for many years [3]. Without guaranteed cost-recovery timelines or precedents for smart-grid investment, utilities and policy makers tend to be reluctant to move toward a smart grid [8].

Technical Risks. Implementation of smart grids requires upgrading of the whole electric system. One great technical challenge is to handle the potential impacts of the high-level penetration of new technologies on existing infrastructure [8]. Developing such an integrated system also places demanding requirements on a wide range of technologies, especially advanced metering infrastructure (AMI) technologies and cost-effective energy storage systems [8]. Moreover, from the perspective of policy makers, the uncertainties associated with smart-grid technologies call for highly flexible regulations to guide the path of its development [8].

Regulation and Monopoly Structure. Most of the electricity markets in the world are still operated by natural monopolies. A typical utility business model today is based upon a negotiated rate of return that adequately recovers utilities' capital investments [3]. As their profits are linked with sales, utilities have a financial incentive to maximize the throughput of electricity across their wires; hence they are often reluctant to adopt technologies that improve the efficiency of power supply. Moreover, rate-of-return regulation requires that utility rates are set to provide a "reasonable" return on invested capital, and utilities have to demonstrate the cost-effectiveness of added investments. As many societal benefits associated with smart grids are not fully understood by regulators, utilities that bear all the cost of smart-grid investments have little incentive to invest in these technologies.

From the consumer's perspective, the current rate design does not reflect the marginal cost of electricity production or the conditions of the wholesale electricity market, which in turn prevents the involvement of the demand side in electricity markets [9]. Without an appropriate pricing mechanism, customers who only receive an end-of-the-month bill tend not to be interested in smart-grid technologies or end-use efficiency [10].

Under current policy schemes, smart-grid technologies face disadvantages when competing conventionally regulated power systems. In order to ensure system reliability, utilities and regulators often pose strict and discriminating rules on interconnection and DG. Incumbent electricity providers and distribution (and transmission) companies have incentives to discourage the deployment of smart grids in light of its potential to increase competition in the electricity market.

There is also a lack of consistency among policies at different levels of governments, which prevents effective collaboration and integration across regions [9].The development of codes and standards often lags behind the development of smart-grid technologies. More efforts are still needed to create universal standards that promote interoperability and compatibility of smart-grid equipment [9].

Incomplete and Imperfect Information. Many consumers still do not see the benefits of a smart grid, nor do they understand the social and economic costs associated with today's outdated power grid system [9]. Utilities and policy makers could play important roles in the process of defining and communicating the benefits of smart grid to customers [3].

Privacy and Security Concerns. Many technologies that enable the deployment of the smart grid, such as smart meters and sensors, can increase the vulnerability of the grid to cyber attacks [3]. As the number of participants and distributed generators in the electric system increases, so does the complexity of security issues [9]. The tension between protection of consumer privacy and development of smart grid also imposes challenges on privacy protection rules. On the one hand, it is essential for both customers and smart-grid service providers to have access to energy consumption data in order to optimize the use of smart-grid technologies. On the other hand, consumer privacy protection may be in favor of the incumbent utilities that are currently controlling the meters and data, hence create barriers to market entry for new smart grid players [10].

Drivers Toward Smart Grids

Apart from barriers, effective policies must also consider drivers that promote investments in smart grid technologies. Over the past few decades, electricity markets and technologies have experienced rapid growth and development, with increasing focus on reliability. The desire for cleaner air through renewable resources and for oil dependence through electric vehicles also motivates interests in the smart grid.

Increasing Electricity Demand. Global electricity demand is expected to increase by over 150% between 2007 and 2050 under the International Energy Agency (IEA)'s Energy Technology Perspectives 2010 Baseline Scenario [11]. Modeling results show modest increases based on high levels of current demand in developed countries and high growth rates in developing countries such as China and India [11].

Electricity demand also varies across time and seasons. There are usually several peak times during the day while peak loads in a year typically occur in summer and winter (Figs. 9.2, 9.3). Due to the rapid development of home appliances and a lack of real-time pricing signals, peak demand increases steadily over time. Since 1982, growth in peak demand for electricity in the United States has exceeded the growth of transmission system by almost 25% every year [4]; and the US peak demand is expected to grow at an average annual rate of 1.7% between 2009 and 2019 [12]. Rising peak demand stresses the electricity system and requires higher reserve margins for unforeseeable outages. Smart-grid technologies can help reduce demand by enabling time-of-use pricing mechanisms and demand response programs and can improve the efficiency of electricity supply through better integration of renewable DG.

Energy Price Escalation and Electricity Reliability Concerns. Rising petroleum prices have underscored the uncertainties associated with the long-term electricity market. Under EIA's Reference and High Oil Price Scenarios, world oil prices are forecast to increase from $59 per barrel in 2009 to $135 and $210 per barrel, respectively, in 2035 [14]. Many countries are responding to the trend of higher

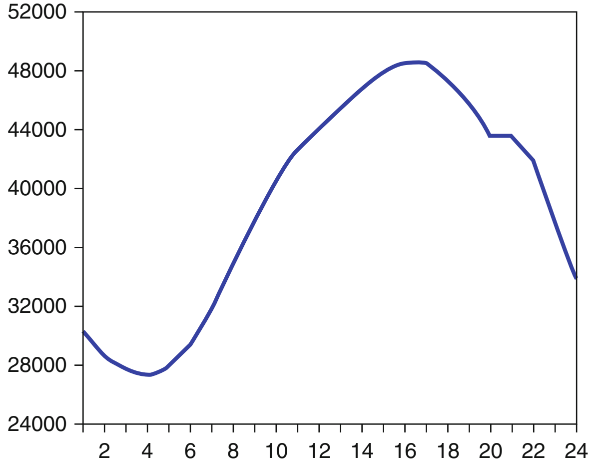


Fig. 9.2 An example of California load curve in July 2005 (MWh)

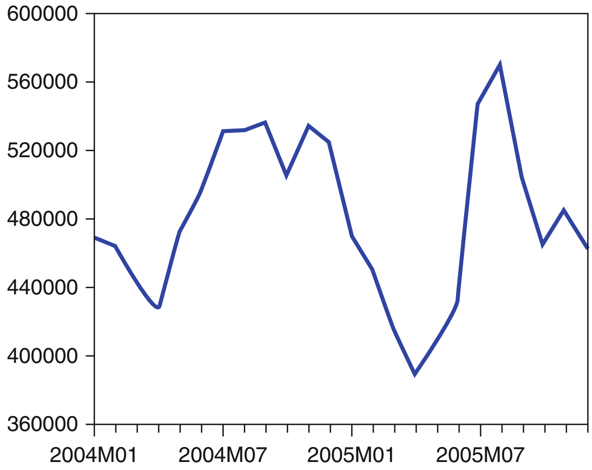


Fig. 9.3 California average daily demand for electricity (MWh) [13]

oil prices by increasing electricity generation from more economical sources and reducing the petroleum dependence of their transportation sector.

At the same time, the aging infrastructure has become increasingly vulnerable to power outages and faces challenges associated with the new demands it needs to meet. The electric systems in many developed countries are largely based upon design requirements and technologies developed in the early twentieth century. The huge economic and social losses caused by supply failures have stimulated efforts to enhance the reliability of electricity supply. Electricity is different from other energy commodities as it cannot be stored in a large scale or be traded at the global level [11]. Electricity production and consumption are highly dependent on grid infrastructures, thus must be continually monitored and controlled to prevent widespread electric service interruption. Smart-grid technologies such as sensors and smart meters allow utilities to monitor the grid system based on real-time information, and enable greater use of demand response programs and distributed renewable energy generation.

Climate Change and Clean Air Concerns. Energy-related human activities are a major source of greenhouse gases and air pollutants. In 2009, the electric power sector in the United States emitted 2,160 million metric tons of CO_2, 2,400 and 5,970 thousand metric tons of NO_x and SO_2 [15, 16]. The electric power and transportation sectors were the largest carbon emission sources in 2009, accounting for 39.8% and 34.1%, respectively, of US total emissions [15]. Many countries have set targets for low-carbon and renewable electricity generation to combat climate change, which require extensive changes to the current power systems. A smart grid could exploit the full potential of carbon emissions reduction and air quality improvement in energy sectors, as it encourages low-carbon power generation and transport systems, and can reduce emission in the transmission process.

Deployment of Renewable Power and Electric Vehicles. Efforts to combat climate change have led to a rapid development of environmentally friendly power generation and transportation technologies. As of 2007, 18.4% of world electricity was generated by renewable energy, and the number will increase to 22.7% by 2035 [14]. The transport sector is also undergoing an electrification revolution, which is expected to consume 10% of total electricity by 2050 [11]. As electric vehicles gain market share, it may become difficult for conventional grid infrastructures to provide reliable and stable electricity services [11]. In particular, the intermittency of renewable energy and electric vehicle charging have to be managed intelligently to avoid supply failures, which provide an excellent opportunity for the deployment of smart grids.

Types of Policies to Promote Smart Grids

This section provides an overview of major smart-grid policies. Current policies address many of the barriers identified above, and are aligned with many key drivers (see Table 9.1).

Net Metering

Net metering allows customers to use a single meter to measure both the inflow and outflow of electricity, thus enabling them to install and interconnect their own generators with utility grids. With net metering, customers can use the electricity generated from their on-site facilities to offset their electricity consumption and sell excess generation to the utility typically at a retail price, which encourages the deployment of customer-owned distributed energy systems. By allowing utilities to

Table 9.1 Smart grid policies to tackle barriers and leverage drivers

	Barriers					Drivers			
Smart grid policies	High costs	Technical risks	Regulation and monopoly structure	Incomplete and imperfect information	Privacy and security	Increasing electricity demand	Rising energy prices and reliability concerns	Climate change and clean air	Deployment of renewable power and electric vehicles
Net metering	×	×	×			×	×	×	×
Interconnection standards	×	×	×	×	×	×	×	×	×
Dynamic pricing	×		×	×		×	×		×
Smart metering targets			×	×		×	×	×	×
Renewable energy subsidies and regulations	×	×	×			×	×	×	×

buy back surplus electricity, net metering helps overcome financial barriers faced by distributed renewable facility owners. The buy-back price is determined by utility regulators to reflect the value of electricity delivered to the grid; therefore, it can differ across regions. In some US states, such as California, net surplus compensation policy is closely related to the state's renewable energy policies, as it includes provisions on the ownership of renewable energy credits associated with the purchase of surplus electricity [17].

Additional policy goals for net metering may include diversification of energy sources, improving system reliability, reducing environmental impacts and distribution costs, and stimulating economic development [18]. Net metering has been widely implemented in countries like the United States and Canada. According to the US Energy Policy Act of 2005, all public electric utilities are required to provide net metering service to their customers upon request [19]. As of June 2011, 43 US states have adopted a net metering policy [20].

Net metering usually requires utilities to offer net metering programs to eligible customers and to design a net energy metering tariff scheme to compensate customers for the electricity generated in excess of on-site load. Customer eligibility for net metering programs varies across regions. Eligibility criteria are commonly defined by sectors (e.g., residential, commercial, and industrial), types of renewable resources (e.g., solar, wind, and combined heat and power (CHP)), and generating capacity (e.g., less that 10 KW or up to 1 MW). Net metering rules are often updated by policy makers to meet the needs and priorities of the market. In general, the trend is to increase the system capacity cap, as in the cases in New York and Massachusetts [21] and to broaden the eligible renewable resources.

Interconnection Standards

Interconnection standards establish uniform processes and technical requirements for utilities when connecting DG systems to the electric grid. It allows DG developers to predict costs and time, and ensure the safety and reliability of interconnection processes. Technical requirements often include protocols and standards that guide how generators shall interconnect with the grid, ranging from system capacity limit, the types of qualifying generators, the types of interconnection equipment required for reliability purposes, to the types of eligible generation technologies. Interconnection policy also includes simplified and standard application, connection and operation procedures, which can reduce uncertainties and prevent time delays that customers could encounter when obtaining approval for grid connection. For example, small systems may qualify for a streamlined interconnection process, with fees and application forms specified in the rules.

Interconnection standards have been widely developed and adopted by both governments and nongovernmental organizations. By 2011, 42 US states adopted an interconnection policy [20]. The US Federal Energy Regulatory Commission (FERC) has developed interconnection standard procedures for generators up to 2 MW, generators between 2 and 20 MW, and generators larger than 20 MW that connect to a utility's transmission system [22]. Other organizations such as the National Association of Regulatory Utility Commissioners (NARUC) and the Institute of Electrical and Electronic Engineers (IEEE) have also developed interconnection standards for distributed resources [23, 24].

Smart Metering Targets

A smart meter is a device that can measure real-time electricity consumption and communicate the information back to the utilities. It usually involves a mix of technologies, including real-time or near real-time sensors, power outage notification, and power quality monitoring. Smart meters, in combination with dynamic pricing, are essential for the promotion of price responsive demand and the success of a smart grid [25]. Smart metering targets have been widely adopted, which often establish smart meter deployment plans for utilities, including the timeline, and the type and number of smart meters to be installed. Sometimes, utilities are required to conduct cost-benefit analysis (CBA) of the proposed smart metering programs.

Demand Response and Dynamic Pricing

Demand response is defined as changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when grid reliability is jeopardized [26]. Many types of demand response programs have been offered by electric utilities and other stakeholders, such as dynamic pricing, peak time rebate, direct load control, and interruptible load. Demand response programs could contribute significantly to peak load reduction. To take the United States as an example, over 500 entities have reported offering demand response programs by 2010, with an estimated demand response resource of more than 58,000 MW (MW), or 7.6% of US peak demand [26].

As one of the most widely implemented demand response programs, dynamic pricing is a market-driven approach to boost demand response in the electricity market. The fundamental idea is to provide accurate price signals to customers and let them decide whether to continue consumption at higher prices or to cut electricity usage during peak times. Under dynamic pricing schemes, utilities charge different rates for electricity based on time, generating cost, and conditions of the grid; hence customers are exposed to some level of electricity price volatility.

There are many types of dynamic pricing policies. The most common ones include time-of-use pricing, critical peak pricing, and real-time pricing.

- **Time-of-Use Pricing (TOU)** sets and publishes electricity prices for different time periods in advance. Electricity prices in peak periods are higher than off-peak, which encourages customers to shift electricity consumption to a lower cost period and reduce the peak demand. The rates for each time block are usually adjusted two or three times each year to reflect changes in the wholesale market; however TOU does not address unforeseen weather conditions or equipment failures.
- **Critical Peak Pricing (CPP)** is similar in rate structure to TOU pricing, but it adds one more rate that can vary with the wholesale market. Electricity prices during a limited number of hours of the year, which refer to the "critical peak hours," rise to levels designed to recover the full generation cost, while electricity prices during other times are lower than the critical periods. There can be a number of CPP event days in a year, and utilities usually will notify customers of the events and rates ahead of time.
- **Real-Time Pricing (RTP)** reflects the hourly or an even smaller time-interval marginal cost of electricity, which can be announced at the beginning of the time period or in advance. RTP can capture most of the true variation in the wholesale market, but it gives customers little time to react to price changes [27]. Technology innovations of the last decade have enhanced customers' ability to respond to real-time prices, and eliminated the conflicting issues between greater advanced price notification and more accurate price signals, enabling the greater use of RTP [27].

Compared to flat rate pricing scheme, dynamic pricing is more effective in promoting energy conservation. There is misperception that customers may be averse to dynamic pricing due to the price volatility and the possibility of paying higher bills; some also argue that customers are insensitive to real-time prices [28]. Research has shown that residential customers generally respond to higher electricity prices by reducing consumption, and both TOU and CPP rates could induce reduction in peak demand [29]. There is also empirical evidence that most low-income customers would save money on their utility bills from dynamic pricing, rather than being negatively affected [30]. Moreover, dynamic pricing may also remove the subsidies embodied in flat rates, which are preserved for social policy reasons but are actually barriers to energy conservation [28].

Enabling dynamic pricing schemes requires the deployment of AMI, which costs from $100 to $200 per meter; however, these costs can be offset by various operational benefits, as well as savings from reduced peak load and avoided capital investment for additional power generation facilities [31]. For instance, the annual long-run benefits associated with a 5% reduction in peak demand in the United States are projected to be $3 billion, representing a discounted present value of $35 billion over a 20-year time horizon [31].

Renewable Energy Subsidies and Regulations

Renewable energy is an essential part of smart grids. Policy makers have developed both financial and regulatory policies to encourage power generation from renewable energy sources, such as feed-in tariffs (FITs) and renewable electricity standards (RES).

FITs are one of the most widely used policy mechanism in the world to encourage the deployment of renewable energy technologies and expansion of renewable energy generation. FITs provide guaranteed long-term purchase agreements for electricity generated from renewable energy sources. Governments usually offer a price for every kilowatt-hour (kWh) of electricity produced based on the types of generation technology, system capacity, and project location. The tariffs might decline over time to track and encourage technology innovation and cost reduction. By 2010, 75 jurisdictions (countries, states, and provinces) have enacted a FIT policy, some of which are developing countries like China, India, Tanzania, and Kenya [32]. FITs create an open and straightforward framework, which not only ensures the long-term stability of revenue from electricity sales, but also reduces risks and overall costs of renewable energy development for society [33]. By 2008, FITs had driven the deployment of 75% of global photovoltaics and 45% of global wind [34].

An RES sets a minimum requirement for the percentage of generation or installed capacity to be provided by renewable energy. Most RES policies require a 5–20% share for renewable energy to be achieved by 2020 and beyond. To achieve RES targets, entities are often allowed to trade renewable energy certificates (RECs), with each certificate representing the certified generation of one unit of renewable energy (typically 1 MWh). As of 2010, RES policies have been implemented by 10 national governments, and 46 state/provincial governments around the world [32].

Other

Many other policies have been designed to address issues in the development process of smart grids, such as consumer protection rules and energy storage policy. Consumer protection rules are particularly important as they create a fair marketplace for both consumers and suppliers [10]. In general, this type of policy includes mandatory disclosure statements and terms and conditions for the contract, which help customers better understand smart grid services. Policy makers also set up rules that regulate the access and usage of customers' personal information and energy consumption data by electric utilities, customers, and third parties. Utilities often have to receive customer consent before releasing the data to a third party.

The inclusion of energy storage systems in grid design and operation can benefit the deployment of smart grid technologies. Related policy issues include cost

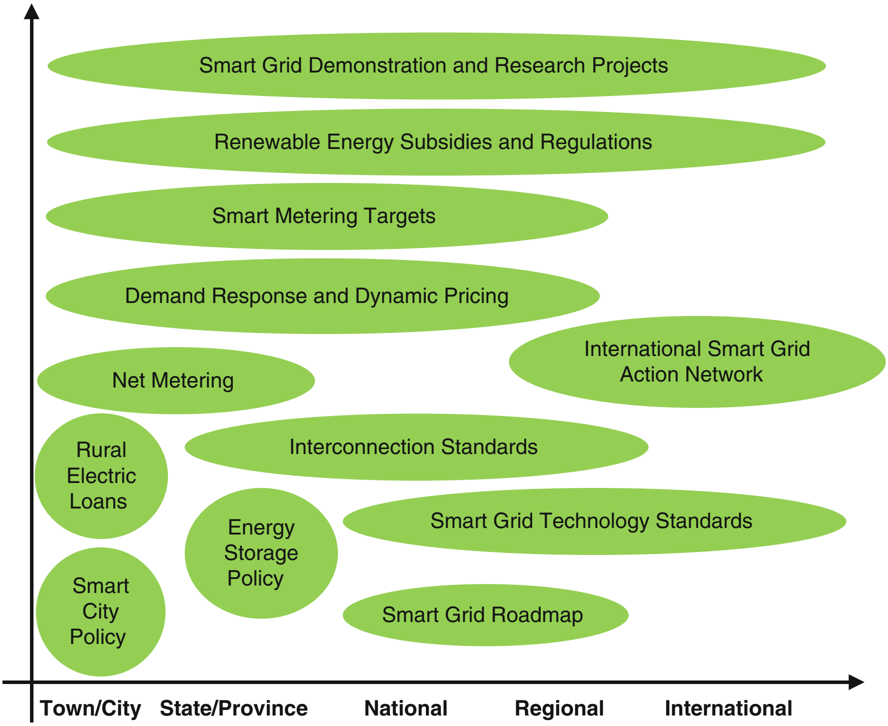


Fig. 9.4 Smart grid policies: moving from the local to the international scale

recovery models of energy storage technologies, incentives to increase private investment, and coherence between energy storage and electric vehicle policies [35]. California is one of the few states that have adopted an energy storage policy. This policy sets up mandatory requirement for developing energy storage systems in the grid. Electric utilities have to procure energy storage systems with a total installed capacity equal or larger than certain percentage of their total peak demand.

Other policies include smart-grid technology standards, customer privacy protection laws, rules governing the ownership of renewable energy credits, smart city policies, and approaches that are tailored to meet the needs of particular regions or market sectors. As shown in Fig. 9.4, these policies span the geographic scale from the local to the international.

Smart-Grid Policies of the United States: Federal Efforts

The United States has been a pioneer in pursuing a low-carbon economy. The government recognizes that a smarter, modernized, and expanded electric system is essential to America's world leadership in a clean-energy future [36]. Development

Table 9.2 Recovery Act overview [39]

Projects	Total obligations (in million $, 2009)	Number of award recipients
Smart grid investment grant	$3,483	99
Smart grid regional and energy storage demonstration projects	$685	42
Workforce development program	$100	52
Interconnection transmission planning	$80	6
State assistance for recovery act related electricity policies	$49	49
Enhancing state energy assurance	$44	50
Enhancing local government energy assurance	$8	43
Interoperability standards and framework	$12	1

of policies has occurred at both federal and state levels to facilitate the evolution toward a twenty-first-century grid. This section first summarizes major policy efforts of the federal government, and provides a stakeholder analysis of the smart grid policy regime in the United States.

Smart-Grid Legislation and Policy Context

In 2005, Congress passed the Energy Policy Act of 2005, which directs utility regulators to consider time-based pricing and other forms of demand response for their states [19]. Utilities are required to provide each customer a time-based rate schedule and a time-based meter upon customer request [19]. The Energy Independence and Security Act (EISA) of 2007 is the key legislation for modernizing the nation's electricity transmission and distribution system. Title XIII of EISA mandates the Secretary of Energy to establish a smart grid advisory committee and a smart grid task force, to assess the impacts of smart grid deployment, and to take the lead in smart grid technology research, development and demonstration projects [37]. It also requires the National Institute of Standards and Technology (NIST) to develop a smart grid interoperability framework that provides protocols and standards for smart-grid technologies [37]. Under Section 1306 of EISA, a smart grid investment matching grant program was established to provide reimbursement of 20% of qualifying smart-grid investments [37].

The American Recovery and Reinvestment Act (ARRA) of 2009 accelerates the development of smart-grid technologies by appropriating $4.5 billion for electricity delivery and energy reliability modernization efforts [38]. Utilities and other investors can apply stimulus grants to pay up to 50% of the qualifying smart grid technology investments. To date, the Smart Grid Investment Grant (SGIG) has 99 recipients, with a total public investment amounting to$3.5 billion [39]. Table 9.2 shows the total obligations and award recipients for the projects authorized by the Recovery Act.

Building on the policy direction set forth in the key legislation, the Federal government published “A Policy Framework for The 21st Century Grid: Enabling Our Secure Energy Future” in June 2011 [36]. This framework identifies and highlights policies that form the nation’s overall grid modernization efforts, presenting them within the context of four policy goals: enabling cost-effective smart-grid investments, unlocking the potential for innovation in the electric sector, empowering consumers and enabling them to make informed decisions, and securing the grid [36].

Roles of Government Agencies

The federal government’s commitment to grid modernization has spurred efforts of many federal agencies and organizations. DOE is leading the nation’s efforts in research, development, and demonstration of smart-grid technologies, and FERC and NIST have been actively engaged in smart-grid technology standard development and implementation. Deployment of smart grids is also closely linked with tasks and missions of many other departments, such as the Environmental Protection Agency’s clean energy and climate change initiatives, the Department of Homeland Security and Department of Defense’s interest in the security and resiliency of electric grid, and the Department of Commerce’s focus on clean energy technology innovation. A summary of responsibilities of major US government agencies is presented in Table 9.3.

Deployment of smart grids involves a wide array of stakeholders, ranging from electricity utilities, consumers, and manufacturers, to government officials. It is critical to understand the impacts of smart-grid deployment on every stakeholder, and his/her potential influences in smart grid policy-making process. Regulatory framework are expected to take into account the conflicting goals and create aligned incentives for various groups. Table 9.4 presents a stakeholder analysis for smart-grid policies in the United States.

Smart-Grid Policies of the United States: State and Local Efforts

The scope and pace of smart-grid deployments naturally vary according to the diverse needs, regulatory environments, energy resources, and legacy systems of different states. Decentralized smart-grid deployment efforts provide local flexibility and stimulate experimentation and innovation in policy design and implementation. Thus, it is useful to examine smart-grid policies developed at the state and local level [138]. In this section, four US states are selected for in-depth investigation: California, Georgia, New York, and Texas.

Table 9.3 Roles of US governmental entities in smart-grid deployment

Agencies	Responsibility
Federal energy regulatory commission (FERC)	Facilitate smart-grid development via its regulations for electricity transmission and wholesale sales: Approve and enforce mandatory reliability standards for bulk power systems Adopt interoperability standards and protocols Provide guidance for the development of smart-grid standards
Department of energy (DOE)	Implement Recovery Act funds for smart-grid deployment Conduct research and development of smart-grid technologies and policies Monitor the progress of smart-grid deployment
Department of agriculture (USDA)	Support grid modernization in rural areas Provide loans for generation, transmission, and distribution of renewable energy
National institute of standards and technology (NIST)	Develop standards for smart-grid technologies Communicate with industry groups to accelerate the adoption of new standards
Smart grid task force	Ensure awareness, coordination and integration of the diverse activities of the federal government related to smart-grid deployment
State public utility commissions	Develop rules to implement state and federal smart grid legislations, such as: Smart-grid standard Dynamic pricing schemes Net metering and interconnection requirements

California

California is one of the leading states in the United States driving the deployment of smart-grid technologies. Its policy efforts are discussed in detail in the following section.

- Net Energy Metering Tariffs
  According to Section 2827 of California Public Utilities Code, all electric utilities in California, except the Los Angeles Department of Water and Power, are required to offer net energy metering (NEM) tariffs to customers who install small solar and wind while investor-owned utilities generation facilities are also required to offer NEM tariffs to biogas and fuel cell customer-generators [40]. NEM tariffs are applicable to qualifying facilities (1 MW and less) in residential, commercial, industrial, and agricultural sectors. The cumulative generating capacity of eligible customer-generators is not to exceed 5% of an electric utility's aggregate customer peak demand.

  NEM customers can get compensation from utilities for electricity generated in excess of on-site load. Net excess generation will be credited to customers' next bill at the retail rate. By the end of a 12-month period, customers can choose to roll over credit indefinitely or to receive financial compensation for credit at a rate that is determined by the California Public Utility Commission (CPUC).

Table 9.4 Stakeholder analysis of smart grid policies

Stakeholder	Pros	Cons	Dominant position	Potential impact on smart grid deployment
Federal government	Job creation, affordable energy, economic competitiveness, energy security, deployment of clean energy resources, emissions reductions	Costs of smart grid demonstration and research projects; reluctance to pick technology winners	Very favorable	High
State legislatures and utility commissions	Job creation, energy security, deployment of renewable energy, emissions reductions	Cost recovery of smart grid investments, vulnerability to cyber attack	Very favorable to slightly favorable	High
Electric utilities	Reduction in peak load, improved grid stability, improved operational efficiency	Reduction in electricity sales, higher workloads vulnerability to cyber attack	Mixed	High
Smart grid and renewable manufacturers	Increased technology and product sales	None	Very favorable	Medium
Conventional energy companies	None	Reduction in sales of fossil fuels	Unfavorable	High
Environmental groups	Decreased emission of criteria air pollutants and greenhouse gases	None	Very favorable	Medium
Customers	Better energy management, reduced energy bill new products and services	Increased risk of privacy invasion, investment costs	Mixed	Low

Table 9.5 Deployment of smart meters by California's large utilities [44–47]

	Pacific Gas and Electric Company	San Diego Gas and Electric Company	Southern California Edison Company
Goal	5.1 million electric meters; 4.2 million gas meter modules	1.4 million electric meters; 0.9 gas meter modules	5.3 million electric meters
Total costs	Ratepayer funding for $1.74 billion approved; $466.76 million approved for proposed project upgrade	$572 million approved	$1.63 billion for upgrade requested
Net benefits	$103.9 million	$40–$51 million	$9–$304 million
Deployment timeline	2007–2011	2007–2011	2008–2012

The owner of renewable DG facilities owns the RECs associated with the electricity generated from the facilities, but utilities could receive RECs for the excess electricity that they have compensated the customers.

- Interconnection Standards: Rule 21
  In 1999, the CPUC instituted rulemaking to address interconnection issues [41], becoming one of the first utility commissions to do so. The resulting Rule 21 has been revised continuously to keep consistency with the requirements of the ANSI/IEEE interconnection standards [42]. Rule 21 mandates that DG facilities meet standard interconnection, operating, and metering requirements. Applicants pay an $800 initial review fee and a $600 supplemental review fee before the utility evaluates the interconnection of the generating facility. For generating facilities that cannot be interconnected to a utility's distribution system via simplified interconnection, additional interconnection studies and fees are required. Rule 21 exempts eligible customers for net energy metering under Public Utilities Code Section 2827 from paying for costs associated with application review fees, interconnection studies, and distribution system modifications. However, eligible customers are responsible for all costs associated with their interconnection facilities.
- Smart Metering Targets
  In 2004, the CPUC directed the three largest investor-owned utilities (IOUs) in California to submit AMI business case analyses and deployment proposals [43]. The three utilities have developed deployment plans for smart meters as part of their smart-grid roadmap and have been given authorization to deploy smart meters throughout their territories (see Table 9.5). The deployment of smart meters is expected to be completed in 2012, when approximately 12 million electric meters and 5 million natural gas meters will be installed, generating hundreds of millions of dollars in net benefits.
- Smart-Grid Legislation
  California passed Senate Bill (SB) 17 in 2009, which establishes regulatory approaches for the CPUC and utilities to deploy smart-grid technologies. The goal of this bill is to maintain reliable and secure electrical service with

infrastructure that can meet future growth in demand, and to achieve other objectives such as the integration of DG resources, demand-side resources, and smart technologies [48]. SB 17 required the CPUC to create a smart grid deployment plan, which laid the groundwork for all IOUs to submit their smart grid deployment plans to the CPUC. The CPUC is also required to conduct impact assessments on relevant state energy initiatives, such as the deployment of AMI, the RES, and greenhouse gas emissions reduction. The bill requires that standards adopted for California be compatible with standards from NIST, FERC, the Gridwise Architecture Council, IEEE, and the North America Electric Reliability Cooperation (NERC). If utilities fail to meet the standards or to present a plan to meet them by the deadline, they will be subject to a penalty.

To facilitate the implementation of SB 17, the CPUC set detailed requirements for utilities' smart-grid deployment plans. Utilities must present a vision of smart grid that is consistent with the legislative initiatives, requiring at least eight topics in their deployment plan, including smart-grid vision statement, deployment baseline, smart-grid strategy, grid security and cyber security strategy, smart-grid roadmap, cost and benefits estimates and metrics [49].

- Customer Privacy Protection Rules
  SB1476 on customer privacy related to AMI became effective in 2010. This bill prohibits utilities from sharing, disclosing, or making accessible to any third party a customer's electrical or gas consumption data [50]. It also requires utilities to protect customers' energy consumption data from unauthorized access, destruction, use, modification, or disclosure, as well as to allow customers to access the data without being required to agree to share their personally identifiable information with a third party [50].
- Dynamic pricing
  The CPUC mandated that dynamic pricing tariff options for all types of customers should be addressed in each utility's comprehensive rate design proceeding application [51]. Furthermore, the CPUC directed each utility "to incorporate default critical peak pricing tariffs for large customers into their next comprehensive rate design proceeding or other appropriate proceeding if directed by the Commission" [52]. In 2010, the CPUC directed the Pacific Gas and Electric Company to implement default and optional critical peak pricing and time-of-use rates (together, referred to as Peak Day Pricing) (see Table 9.6) [53]. There will be between 9 and 15 Peak Day Pricing event days for each calendar year, and for their first year on a Peak Day Pricing rate scheme, customers will be afforded bill stabilization and can choose to opt out any time [53].

  Southern California Edison Company has also developed several dynamic pricing schemes. It offers voluntary CPP for all its customers, real-time pricing rates to customers with monthly peak demand greater than 500 kW, and agricultural and pumping real time pricing rates to customers who use 70% or more of the electricity for general agricultural purposes, or for general water or sewage pumping [54].
- Energy Storage Bill
  The California State Assembly passed the nation's first energy storage bill (Assembly Bill 2514) in September 2010. This bill mandated utilities to procure

Table 9.6 Pacific Gas and Electric Company peak day pricing transition plan [53]

Applicable sector	Type of rates	Options
Residential customers with advanced meters	Peak day pricing; non-time-differentiated residential tiered rates	Allows customers to transition to either of the two rates
Large commercial and industrial customers ($\geq$200 kW)	Peak day pricing rates that include time-of-use rates during non-peak day pricing periods	Default; Allows customers to opt out to a time-of-use rate or other time-variant rate
Small and medium commercial and industrial customers ($\leq$200 kW)	Peak day pricing rates that include time-of-use rates during non-peak day pricing periods	Default; Allows customers to opt out to a time-of-use rate or other time-variant rate
Large agricultural customers ($\geq$200 kW)	Peak day pricing rates that include time-of-use rates during non-peak day pricing periods	Default; Allows customers to opt out to a time-of-use rate or other time-variant rate
Small agricultural customers ($\leq$200 kW)	Time of use	Default

new grid-connected energy storage systems [55]. Before October 2013, the CPUC will determine two energy storage procurement targets for utilities to achieve by 2015 and 2020 [55].

- Distributed Generation and Renewable Energy Credits
  Because RECs are critical to the cost-effectiveness of renewable DG facilities, the CPUC has issued several decisions to clarify the participation of renewable DG in the renewable electricity standards. Specifically, "the owner of the renewable DG facilities owns the RECs associated with the generation of electricity from those facilities" [56]. Decision 07-01-018 further states that "utilities will not be counting the output of renewable DG facilities that have received ratepayer incentives toward their renewable portfolio standard obligations." In other words, renewable DG facility owners will retain the RECs produced by their facilities irrespective of whether or not they receive ratepayer funding from programs such as SGIP (see below) or net metering [57].

  The CPUC established the Self-Generation Incentive Program (SGIP) to encourage the development and commercialization of DG technologies. SGIP provides financial incentives to certain entities that install DG (such as micro-turbines, small gas turbines, wind turbines, photovoltaics, fuel cells, and internal combustion engines) to offset some portion of the customer's on-site load (see Table 9.7) [58]. Due to insufficient funds, the SGIP was terminated in early 2011 [59].

Georgia

Georgia has a broad array of dynamic pricing programs, but relative to California its net metering and interconnection standards are more restrictive. The State also has one of the lowest rates of renewable electricity generation in the country [60].

Table 9.7 Financial incentives and eligibility of the SGIP [57]

Incentive category	Incentive offered	Maximum percentage of project cost (%)	Eligible system size	Eligible technologies
Level 1	$4.50/W	50	30 kW	$\sim$1 MW
	Photovoltaics;	Fuel cells operating on renewable fuel; Wind turbines		
Level 2	$2.50/W	40	$\leq$1 MW	Fuel cells operating on nonrenewable fuel and utilizing sufficient waste heat recovery
Level 3	$1.00/W	30	$\leq$1 MW	Microturbines utilizing sufficient waste heat recovery and meeting reliability criteria; Internal combustion engines and small gas turbines, both utilizing sufficient waste heat recovery and meeting reliability criteria

- Net Metering
  Georgia General Assembly passed the Georgia Cogeneration and Distributed Generation Act of 2001 to encourage private investment in renewable energy [61]. This act requires utilities to provide net metering for all eligible customers. DG facilities are customer-owned and they use photovoltaic systems, wind turbines, and/or fuel cells. The peak generating capacity of eligible systems must be smaller than 10 kW for residential customers and 100 kW for commercial customers. The cumulative generating capacity of net-metered systems is limited to 0.2% of a utility's annual peak demand in the previous year (recall that California's cap was much higher, at 5% of an electric utility's aggregate customer peak demand). Utilities are required to offer bidirectional or single directional metering depending on how the DG facilities are installed. Systems connected on the customer's side of the meter are required to use a bidirectional meter, and any net excess generation will be credited to the customer's next bill at tariffs filed with the Georgia Public Service Commission. Systems connected on the utility's side use a single directional meter, and the customer will be charged with a minimum monthly service fee.
  In particular, solar photovoltaic generation is encouraged under Georgia's net metering policy scheme. Georgia Power, the dominant utility in the state, operates the Solar Buyback Program, which allows customers to sell electricity produced by solar panels [62]. Georgia Power is responsible for meter installation, but it charges a $3.97 and a $1.31 monthly metering fee, respectively, for single directional metering and bidirectional metering. The solar purchase tariffs are subject to change according to state policies. Through 2010, the Solar

Purchase Price was 17 cents per kWh, and the aggregate energy purchases were limited to 2.9 MW. Starting in 2011, solar photovoltaic electricity is purchased at Avoided Solar Cost.

- Interconnection Standards
  The Cogeneration and Distributed Generation Act of 2001 allows certain residential (smaller than 10 kW) and commercial (smaller than 100 kW) facilities that use photovoltaic system, wind turbines, and fuel cells to interconnect and receive net metering tariffs from utilities [61]. This act requires customers to meet applicable interconnection requirements, such as the National Electrical Code, National Electrical Safety Code, and the IEEE standards.
- Smart Metering Targets
  Georgia Power has installed about one million smart meters since 2008, and it plans to provide every customer with a smart meter by the end of 2012 [63]. No additional service charge will be added to customers' energy bill. Few of these smart meters provide real-time information to consumers; they mostly automate the collection of consumption data by the utility.
- Dynamic Pricing
  Georgia Power has been very successful in implementing dynamic pricing programs. An array of dynamic pricing programs is offered to various types of customers, with electricity rates ranging from 1.25 cents per kWh during super off-peak time to 19.29 cents during on-peak hours (see Table 9.8). For instance, TOU rates are available to residential customers and electric vehicle owners, as well as small, medium, and large businesses. RTP for some customers are based on day-ahead or hour-ahead power supply prices. In 2005, Georgia Power's commercial and industrial real-time pricing programs alone had 1,600 participants, which represented over 5,000 MW of qualifying load [64].

New York

The State of New York was one of the first states to develop standard interconnection requirements, which specified application fees as well as limits to customer costs for interconnection equipment.

- Net Metering
  New York Public Service Law requires utilities to provide interconnection and net metering for solar, wind, farm waste, micro-CHP, and fuel cell generating facilities [66]. The generating capacity cap varies by technology and sector (see Table 9.9). The aggregate generating capacity cap for wind was 0.3% of a utility's total electric demand in 2005, and the aggregate generating capacity cap for solar, biogas, micro-CHP, and fuel cell systems combined is set at 1.0% of a utility's 2005 electric demand (this is between the lower value for Georgia and a higher value for California). The New York State Public Service Commission (PSC) and utilities are encouraged to increase the cap for aggregate generating capacity.
- Interconnection Standards

Table 9.8 Dynamic pricing programs offered by Georgia Power Company [65]

Applicable customers	Type of rates	Electricity rate (cents per kWh)	
Residential	Time-of-use rate	On-peak: 2–7 pm, Mon–Fri, June–Sept	19.29
		Off-peak: all hours not included above	4.36
Plug-in electric vehicle	Time-of-use rate	On-peak: 2–7 pm, Mon–Fri, June–Sept	19.29
		Off-peak: 7 am–11 pm for weekends, holidays, and Oct–May; 7 am–2 pm and 7 pm–11 pm, Mon–Fri, June–Sept	5.83
		Super off-peak: 11 pm–7 am, Mon–Sun for all calendar months	1.25
Small business	Time-of-use rate	On-peak: 2–7 pm, Mon–Fri, June–Sept (not including holidays)	16.17
		Off-peak: all hours not included above	June–Sept: 7.30 Oct–May: 7.30 for the first 1,500 kWh; 2.79for usage above 1,500 kWh
Medium Business	Time-of-use rate	On-peak: 2–7 pm, Mon–Fri, June–Sept (not including holidays)	11.69
		Shoulder: 12–2:00 pm and 7–9 pm, Mon–Fri, June–Sept (not including holidays)	5.61
		Off-peak: all hours not included above	2.11
Large business	Time-of-use rate	On-peak: 2–7 pm, Mon–Fri, June–Sept (not including holidays)	9.56
		Shoulder: 12–2:00 pm and 7–9 pm, Mon–Fri, June–Sept (not including holidays)	4.32
		Off-peak: all hours not included above	1.51
Customers with a peak 30-min demand larger than 250 kW each month	Real time pricing – day ahead	Hourly prices are determined each day	
Customers with a peak 30-min demand larger than 5,000 kW each month	Real time pricing – hour ahead	Prices are updated each hour, 60 min before becoming effective	

Table 9.9 Generating capacity cap for eligible distributed facilities in the state of New York [66]

Applicable sector	Solar	Wind	Biogas	Micro-CHP and fuel cells
Residential	25 kW	25 kW	–	10 kW
Nonresidential	2 MW	2 MW	–	–
Farm-based	–	500 kW	1 MW	–

The New York PSC first developed the Standard Interconnection Requirements (SIR) for DG units in 1999, and has amended it many times [67]. The SIR of 2010 contains interconnection and application procedures for distributed facilities 25 kW or less and systems between 25 kW and 2 MW [68]. There is no application fee for applicants proposing to install systems 25 kW or less, but they are responsible for costs of installing the dedicated transformers and other safety equipment if deemed necessary. For systems above 25 kW and up to 2 MW, a nonrefundable $350 application fee is required, and the utility will conduct a preliminary review and a coordinated electric system interconnection review to determine if the proposed facility results in any relay coordination, fault current, and/or voltage regulation problems. The SIR also determines the maximum expense for interconnection equipment that has to be paid by customers. For technical standards, the SIR sets requirements for the design and operation of DG facilities, which are consistent with the IEEE standard 1547.

- Smart Metering Targets
  In an order issued in 1997, the New York PSC views advanced metering as a potential way to develop a robust and competitive retail market [69]. Eligible large commercial and industrial customers were to have the option of owning a Commission-approved meter. Utilities are to provide at least 24 months of customer's energy consumption data at no cost upon a customer request; and they will provide any third party the same data with the customer's approval. This order also states that utilities will invest in smart metering technologies only if it is cost-effective. In 2006, the New York PSC adopted an order to encourage utilities' investment in cost-effective smart metering programs and pilot projects to test various proposals for smart metering deployment [70]. Utilities are also required to file plans and proposals for integrating smart meters into their systems.
- Dynamic Pricing
  In 2005, the New York PSC directed major utilities in the state to accelerate and implement mandatory hourly pricing (MHP) for their largest customers [71]. An order issued in 2006 requires major utilities to develop methods for deriving retail hourly prices, to assess the impacts of MHP, and to submit a report on program implementation [72]. Consolidated Edison Company of New York, Inc. was directed to offer MHP to customers with peak demand greater than 1,500 kW. As of July 2011, this program has been expanded twice and it is now available for customers with peak demand greater than 500 kW [73]. The 2006 order also mandates National Grid to implement MHP for its medium-sized

commercial and industrial customers, and requires New York State Electric & Gas Corporation, Rochester Gas and Electric Corporation, and Orange & Rockland Utilities, Inc., to implement MHP for their time-of-use customers at or above 1,000 kW [72]. In 2011, New York PSC approved Rochester Gas & Electric's plan for expanding its MHP program to customers with peak demand greater than 300 kW, which would add an additional 585 MHP customers to this program [74].

Texas

Texas is the only one of the four States examined in this chapter that requires utilities to offer unlimited cumulative generating capacity under their net metering programs.

- Net Metering
  Texas does not have a statewide net metering policy; however, utilities can, but are not required to, compensate customers for electricity that is generated from distributed renewable resources and sent back to the grid. According to the Public Utility Commission of Texas (PUCT), utilities in Texas are required upon customers' request to provide one or two meters that can separately measure both the inflow and outflow of electricity [75]. Qualifying facilities include distributed renewable generators with a capacity up to 2,000 kW [75]. Beginning in 2009, the PUCT requires each utility to offer qualifying renewable generation facilities that have an aggregate design capacity of 50 kW or less the option of interconnection through a net meter [76]. Excess generation will be purchased by utilities at the avoided cost, and there is no limit on the cumulative generating capacity under the net metering program [76].

  Many municipalities and large utilities in Texas have their own net metering programs. For instance, Austin Energy offers a net metering program for renewable energy systems with a generating capacity less than 20 kW [77]. Eligible technologies include solar, wind, geothermal, hydroelectric, wave and tidal energy, biomass, and biomass-based waste products.
- Interconnection Standards
  PUCT rules address the technical and procedural aspects of interconnection of on-site DG facilities [78, 79]. The rules establish interconnection standards that apply to generating facilities with a maximum capacity of 10 MW and connection at a voltage less than 60 kV. In particular, requirements for generators, network interconnection of DG, and control, protection, and safety equipment are specified to ensure safety and reliability of the interconnection. Customers who fail to comply with the standards may be disconnected from the grid. Pre-interconnection studies and fees will be considered based on the characteristics of DG facilities; for instance, customers with DG facilities less than 500 kW that export less than 15% of the total load and contribute less than 25% of the

Table 9.10 Deployment of smart meters by the three largest utilities in Texas

	Center point	Oncor	AEP Texas
Goal	2.1 million electric meters	3.4 million electric meters	1.1 million electric meters
Achievement as of August 31, 2010	615,518 electric meters	1,251,838 electric meters	78,705 electric meters
Deployment timeline	2009–2012	2008–2012	2009–2013

maximum potential short circuit current on a single radial feeder will not be charged with the pre-interconnection study fee [78].

PUCT also published a Distributed Generation Interconnection Manual to help utilities process interconnection applications. It includes safety and technical requirements of DG installations, applicable rules, application procedures and forms, Texas utility contacts, and equipment pre-certification requirements [80]. Texas utilities are required to evaluate applications based on prespecified criteria, including equipment size and the relative size of the DG system to the feeder load.

- Smart Metering Targets
  Currently, there is no legislation that requires mandatory deployment of smart meters in Texas. However, the state legislature has taken actions to provide more regulatory incentives for smart meter deployment. In 2005, Texas passed House Bill (HB) 2129 to encourage energy saving measures. This bill recognizes the important role that smart meters can play in grid modernization and energy conservation, and encourages the deployment of smart meters by utilities in Texas [81]. It also directs the PUCT to establish a non-bypassable surcharge for a utility to recover reasonable and necessary costs incurred in deploying advanced metering and metering information networks [81]. A subsequent Texas law encourages the development of net metering and advanced meter information networks to allow demand-side energy management and to facilitate demand response initiatives [82].

  Although there is no mandatory smart metering policy, utilities in Texas have been very active in deploying smart meters. The three largest utility companies have all received approval from the PUCT regarding the deployment of smart meters in their territories (see Table 9.10) [83]. As of August 2010, two million smart meters have been installed, and the total number will reach 6.6 million by the end of 2013. Electric utilities in Texas also established the Smart Meter Texas web portal in 2010, which can provide 15-min energy usage data to retail electric providers and customers with a smart meter [84].
- Customer Privacy Protection Law
  HB2129 sets requirements regarding data security and privacy of smart meters. It states that all meter data, including data used to calculate charges for service, historical load data, and any other proprietary customer information, shall belong to a customer. A customer could allow retail electric providers (REPs) to access the data under rules and charges established by the PUCT [81].

- Dynamic Pricing
  A demand response study by FERC found that Texas has the most potential for demand response initiatives, with more than 18 GW expected by 2019 [12]. However, currently there is very little demand response in place, and no mandatory regulations on dynamic pricing. Nevertheless, several electric utility companies offer voluntary dynamic pricing rates. For instance, TOU rate is available for TXU Energy's residential customers who have had smart meters installed at their premises [83]. Participating customers pay 21.9 cent per kWh during summer afternoons (1–6 pm on weekdays from May to October), and 7.9 cent per kWh during off-peak hours.

Smart-Grid Policies of the European Union

The European Union (EU) is the second largest energy market in the world, with over 450 million customers [85]. The objective of European energy policies in the twenty-first century is to achieve a sustainable, competitive, and secure energy supply [86]. Deployment of smart grid forms an essential part of EU's climate change and clean energy initiatives, as it promotes revolution in traditional electricity markets and networks. This section summarizes EU's policies and regulations relating to the deployment of smart-grid technologies. It also examines the smart-grid policy efforts of two EU member countries: Italy and the UK.

Smart-Grid Legislation and Policy Context

- Directive 2001/77/EC
  This Directive requires member states to ensure the transmission and distribution of electricity produced from renewable energy sources without prejudice [87]. Member states are required to publish interconnection standards and rules to facilitate the integration of renewable energy sources into the grid. Transmission and distribution system operators shall provide a comprehensive and detailed estimate of interconnection costs upon customers' request, and publish standard rules regarding the sharing of installation costs.
- Directive 2003/54/EC
  This directive establishes common rules for electricity generation, transmission, distribution, and supply [88]. It mandates member states to publish technical rules and standards governing the interoperability of systems and interconnection activities. Member states are encouraged to implement energy efficiency/demand side management programs to achieve social, economic, and environmental objectives.
- Green Paper on Energy Efficiency or Doing More with Less (2005)
  This Green Paper calls for wide deployment of smart meters and implementation of dynamic pricing programs to promote more economical and rational energy

consumption [85]. Policies shall also be designed to encourage the shift from centralized generation to DG.

- Green Paper – A European Strategy for Sustainable, Competitive, and Secure Energy (2006)
  This Green Paper which was published in 2006 emphasizes that Europe has entered into a new energy era [86]. It provides suggestions and options that form the basis of a new energy policy scheme. This document proposes a European grid code that encourages harmonized grid access conditions and allows customers to purchase electricity and gas from suppliers in other member states. It also suggests that member states develop a plan to increase the interconnection levels between countries.
- Directive 2006/32/EC
  This directive aims to encourage cost-effective and efficient energy consumption in the EU. Member states are required to achieve an energy saving target of 9% by the ninth year of application of this directive. The deployment of appliances and information technologies in residential and commercial sectors will play a significant role in reducing electricity consumption in the future. For instance, this directive recommends intelligent metering systems as one of the eligible energy efficiency improvement measures [89]. Member states are encouraged to subsidize the deployment of improved metering and informative billing.
- Directive 2009/72/EC
  This directive recognizes that innovative pricing formulas, intelligent metering systems, and smart grids are important measures to promote energy efficiency [90]. It mandates member countries to conduct CBA of smart metering programs and requires that 80% of consumers shall be equipped with intelligent metering systems by 2020. This directive also mandates member countries to encourage the development of smart grids to promote decentralized generation and energy conservation.
- Conclusions of the European Council of February 4, 2011
  The Conclusions set the goal of adopting technical standards for electric vehicle charging systems by mid-2011 and for smart grids and meters by the end of 2012 [91].
- Communication "Smart Grid: From Innovation to Deployment"
  This Communication summarizes the current and past policy initiatives that address challenges to smart-grid deployment [92]. Five aspects of government efforts are highlighted: developing common European smart-grid standards, addressing data privacy and security issues, regulatory incentives for smart-grid deployment, smart grids in a competitive retail market in the interest of consumers, and continuous support for innovation and its rapid application.

Smart-Grid Standards

The Conclusions of the European Council of February 4, 2011 confirm that there is an urgent need to adopt European standards for smart grids. To date, the European

Commission (EC) has issued three mandates to European Standardization Organizations (ESOs) relating to European standardization policies.

- European Commission Standardization Mandate for Smart Meters (M/441)
  This mandate invites ESOs to develop European standards which will enable interoperability of smart utility meters (electricity, gas, water, and heat) [93].
- European Commission Standardization Mandate for Electric Vehicles (M/468)
  ESOs are requested to develop European standards or to review existing standards to ensure the interoperability and connectivity related to the charging of electric vehicles [94].
- European Commission Standardization Mandate for Smart Grids (M/490)
  This mandate requires ESOs to develop a framework that consists of technical reference architecture, a set of consistent standards and sustainable standardization processes and collaborative tools to enable the continuous standard enhancement and development in the field of smart grids [95].

Government Agencies and Organizations

The EC's Directorate-General for Energy leads the policy development and implementation of energy-related topics, such as smart grids, energy efficiency, security of energy supply, nuclear energy, and renewable energy. Its sub-Directorate B for Security of Supply, Energy Markets & Networks is the most active player in the EU smart grid policy arena. The work of the Directorate-General for Energy is supported by other important government agencies including the Agency for the Cooperation of Energy Regulators (ACER) and the Executive Agency for Competitiveness and Innovation (EACI).

In November 2009, the European Smart Grids Task Force was established to advise the EC on smart-grid policies between 2010 and 2020. It also coordinates and cooperates with other major stakeholders in this area to facilitate smart grids deployment in Europe, including the Smart Grids European Technology Platform, Smart Grids Forum, and the European Electricity Grids Initiatives (EEGI).

funding mechanisms

The research and development of smart-grid technologies have been receiving financial support from the Framework Program (FPs), the main financial tool through which EU supports research and development activities in a wide range of scientific subjects. The current FP – the Seventh FP (FP7) runs from 2007 to 2013, with a total budget of €50,521 million ($71.5 billion US dollars) [96]. Over the last decade, around €300 million ($424.4 million US dollars) has been spent on smart grid pilot projects [92].

The EC adopted the Recommendation on Mobilizing Information and Communications Technologies to facilitate the transition to an energy-efficient, low-carbon economy in October 2009 [58]. Information and Communications Technologies (ICTs) are seen as important contributors to the achievements of EU's energy and climate goals [97]. Many smart grid projects are funded by the FP-ICT for Energy Efficiency and the Competitiveness and Innovation Framework Program (CIP)-ICT Policy Support Program [98].

- The ADDRESS project
  Active Distribution Network with Full Integration of Demand and Distributed Energy Resources (ADDRESS) is a large-scale project funded by the EC under the seventh FP in the Energy area for the "Smart Energy Networks – Development of Interactive Distribution Energy Networks." The total budget for this project is €16 million ($23 million US dollars), with €9 million ($13 million US dollars) financed by the EC [99]. It is being carried out by a consortium of 25 partners from 11 European countries between 2008 and 2012, under the coordination of one of the largest utilities in Europe – Enel Distribuzione. Partners include universities, research institutes, distribution and transmission network operators, energy supply and retail companies, electric equipment manufacturers, home appliance manufacturers and consultants, and ICT providers and electric equipment manufacturers. The goal of this project is to enable the participation of small and medium customers in the electric market, and finally realize the vision of the European Smart Grids Technology Platform – developing a network that is flexible, reliable, accessible, and economic.

Smart-Grid Policies in Italy and the UK

- Italy
  In line with the provisions of Directive 2009/28/EC, the Italian government issued the "Italian National Renewable Energy Action Plan" in June 2010. The plan provides measures to encourage the modernization of transmission and distribution networks, the integrated management of various generation systems and loads (including electric vehicles), and power generation from renewable sources [100].

  The Interregional Operational Plan for Renewable Energy Sources and Energy Saving was approved by the EC in December 2007, with the aim to "increase the ratio of load supplied by renewable and the energy efficiency, promoting the local development opportunities in four Italian Southern regions: Campania, Puglia, Calabria, Sicilia" [101]. A total of €1.6 billion ($2.3 billion US dollars) was allocated to the program for the period of 2007–2013, with €803 million ($1.23 billion US dollars) provided by the European Regional Development Fund (ERDF) [101]. One focus of this program is to improve the infrastructure of transmission networks to promote renewable energy sources and

CHP generation, which receives €100 million funding from ERDF and Italian state funds [100]. In this context, the Ministry of Economic Development and Enel Distribuzione together launched a €77 million "Smart Medium Voltage Networks" project in southern Italy to make the medium voltage distribution networks more favorable to photovoltaic systems with installed capacity between 100 kW and 1 MW [100]. The Italian utility regulator (Autoritàper l' Energia Elettricaedil Gas) has awarded eight tariff-based financial projects on active medium voltage networks, to demonstrate at-scale advanced network management and automation solutions necessary to integrate DG [102].

Italy has one of the largest and most extensive smart metering programs in the world. Enel Distribuzione, the largest power company in Italy and the second listed utility by installed capacity in Europe, has already completed the installation of smart meters in its electrical distribution system. Thirty-two million customers can have access to more efficient and flexible services brought by smart meters, such as the hourly based tariff system introduced in 2005 [103]. The company has plans to install smart meters for its gas distribution grid, and extend the smart metering system to its distribution grids in Spain, where 13 million smart meters will be installed during the period 2010–2015 [103]. Enel Distribuzione also launched the E-mobility Italy program in three Italian cities: Rome, Milan, and Pisa in 2008 [104]. The program will deliver 100 electric vehicles to selected drivers in the three cities, and build 400 intelligent electric vehicle recharging stations.

- United Kingdom

The renewable target for the UK is to generate 15% of its energy from renewables by 2020, which requires 30% of its electricity to come from renewables by that time [105]. The British government issued the Carbon Plan in 2011, which sets a firm, long-term and legally binding framework to cut emissions by at least 34% by 2020 and 80% by 2050 – below the 1990 baseline [106]. The British government sees smart grids as an effective approach to meet challenges of energy security and climate change, as well as to achieve a low-carbon economy. In the Carbon Plan, smart metering is identified as a way for energy efficiency improvements, as it can change consumer behavior. Under Sections 88–91 of the 2008 Energy Act, the Secretary of State is allowed to modify energy distribution and supply licenses to force the license holders to install or facilitate the installation of smart meters [107]. This Act also introduces the FITs for low-carbon electricity generation facilities with a generating capacity less than 5 MW. Eligible technologies include biomass, biofuels, fuel cells, photovoltaics, waves and tides, wind, solar power, geothermal sources, and CHP systems with a capacity of 50 kW or less.

The Energy Bill 2010–2011, together with its provisions for the new "Green Deal," was first introduced in December 2010. It aims to facilitate the country's energy efficiency improvements by providing financial incentives to householders, private landlords, and businesses [108]. Smart metering is an essential part of the Green Deal.

In July 2010, the Department of Energy and Climate Change (DECC) and Office of the Gas and Electricity Markets (Ofgem) published the "Smart Metering Implementation Program: Prospectus" which sets out detailed proposals for the delivery of smart and advanced meters to all homes and small businesses in Great Britain. This prospectus sets design requirements, central communications, data management, and the rollout plan for the deployment of smart meters, and it seeks responses from the public on a number of questions [109].

DECC and Ofgem jointly published the government's response to the Smart Meter Prospectus in March 2011 [110]. According to this document, suppliers are required to provide smart meters to smaller nondomestic sectors, and both smart meters and in-home display (IHD) will be provided to domestic customers. Smart meter equipment and devices will have to meet the technical standards in the Functional Requirements Catalog, which was published alongside this document. With respect to privacy protection, customers will be able to choose how their consumption data is used and by whom, except where data is required for regulatory purposes. The British government expects full rollout of smart metering by 2019. It is estimated that over 50 million electricity and gas meters will be installed, with a total financial investment of over £11 billion ($17.6 billion US dollars) and a net benefit of more than £7 billion ($11.2 billion US dollars) [110]. However, a report published by the National Audit Office concludes that there is a high level of uncertainty with regard to the extent to which smart meters will bring changes in customers' energy consumption patterns [111]. It recommends DECC and Ofgem to develop benefits realization plans and customer engagement strategy to minimize the potential risk.

Smart-Grid Policies of Other Countries

Japan

The electricity supply in Japan is highly reliable with a power failure time per year/ per household of only 16 minutes compared to 162 minutes in the U.S. [112]. However, Japan aims to reduce carbon emissions by 30% by 2030 compared to the 1990 level [113]. Renewable energy and energy efficiency are expected to play an important role in achieving this goal. Thus, smart-grid investments are needed.

Japan's deployment approach is slightly different from other countries. Smart-grid deployment is seen as creating an opportunity for Japanese industries to gain competitiveness in the global market. The concept of "smart community," which refers to a new, intelligent, and sustainable way of living, not only stimulates changes in the electricity market, but also motivates innovations in automobiles, telecommunications, and home appliances industries.

The Ministry of Economy, Trade and Industry of Japan (METI) is the major government agency responsible for smart-grid development. Its objectives are to enable further integration of renewable energy, facilitate the development of electric vehicles and the charging infrastructure, and create new services using smart meters and ICT networks [114]. In 2009, the METI invested over $73 million on three demonstration projects: Remote Island Smart Grid Project, Smart Charge Project, and Smart House Project. Technologies that were tested include battery storage, electric vehicle charging system, residential photovoltaics, fuel cells, and demand response appliances. In 2010, the METI launched four large-scale smart community pilot projects in Kansai Science City, Yokohama City, Kitakyushu City, and Toyota City [115]. The primary goal of these projects is to develop Community Energy Management Systems, which are a combination of technologies including smart meters, home energy management systems, building and energy management systems, electric vehicles, photovoltaics, and batteries. Four smart community demonstration projects located in the State of New Mexico (US), Hawaii (US), Lyon (France), and Malaga (Spain) have also been carried out by the New Energy and Industrial Technology Development Organization (NEDO), an administrative branch of the METI [116]. These projects aim to prepare for the large-scale introduction of renewable energy, power storage, and electrical vehicle management systems.

There have been increasing cooperation and collaboration between Japan's public and private sectors in the deployment of smart grids. For instance, the Japan Smart Community Alliance established by NEDO in 2010 provides a platform for the participation of a wide range of stakeholders, including industries, electric utilities, government agencies, and research institutes [117]. Toshiba Corporation, Tokyo Electric Corporation, and the Tokyo Electric Power Company are also working together to launch a venture into the commercialization of smart meters [118]. The large-scale deployment of smart meters will start from 2013, and the goal is to have smart meters installed in all households across Tokyo Electric Power's service area.

Another challenge faced by Japan is energy security, as over 90% of energy consumed by Japan is imported. The Japanese government's goal is to have 70% of its electricity generated from zero-emission sources, and almost double its energy independence by 2030 [113]. In order to achieve this target, the government is developing a FIT scheme to purchase renewable energy generated in Japan. The "New Purchase System for Photovoltaic Electricity" was launched on November 1, 2009 [119]. Surplus electricity generated from solar photovoltaics is purchased at ¥48/kWh ($0.59/kWh) for residential sector, and ¥24/kWh ($0.30/kWh) for industries, businesses, and schools. The buyback prices will decrease each year based on the innovation and price trends of solar photovoltaic technologies.

The Republic of Korea

The electric system of the Republic of Korea is more reliable and efficient compared to many other developed countries [120]. However, the country is highly dependent on imported petroleum and liquefied natural gas. It imports over 90% of the total energy consumed, and has only 2.7% produced from renewable energy sources [121]. The greenhouse gases emissions of Korea also are expected to increase more rapidly than many other developed countries: by 2035, its carbon emissions will increase 35% from the 2002 base line, compared to less than 15% for all the OECD countries [121]. Although as a non-Annex I Party, Korea does not have obligations to reduce carbon emissions under the Kyoto Protocol, the Korean government sets a voluntary goal of reducing its greenhouse gas emissions by 30% below the business-as-usual case by 2020 [121]. Reducing the nation's energy dependence and carbon intensity is one of the top priorities of the Korean government.

The deployment of smart-grid technologies has started since 2005. Korea launched the Power IT National Program in order to develop digital, environmental-friendly and intelligent electric power devices and systems, and advance Korean electric power and electrical industries [122]. Ten projects were selected for systematic implementation, including development of energy management systems, intelligent transmission and distribution networks, advanced substation automation systems, power equipment monitoring systems, power line communication ubiquitous technology, power semiconductor, and consumer portal systems.

In August 2008, President Lee Myung-bak announced "Korea's National Strategy for Green Growth," which proposes a total investment of 107 trillion won (US $101 billion) between 2009 and 2013[121]. The deployment of smart-grid technologies is a key part of this five-year plan. Among the 27 core green technologies listed in the national plan, more than one third is related to the development of smart grid and smart cities.

The Korea government has announced the "Smart Grid Road Map 2030" as a key step to build a low-carbon, green growth economy in the long run [123]. The roadmap will be implemented in five sectors: smart power grid, smart consumers, smart transportation, smart renewables, and smart electricity services. By 2030, a nationwide smart grid and 27,140 power charge stations for electric vehicles will be built; and the penetration rate of smart meters and AMI will reach 100% by 2020. Besides, Korea will have 11% of its energy from renewables, and achieve a maximum of 10% power reduction by 2030. The annual blackout time per household will be reduced from 15 min in 2012 to 9 min in 2030, and the power transmission and distribution loss rate will decrease from 3.9% in 2012 to 3.0% in 2030. A total of 27.5 trillion won ($25.85 billion US dollars) will be allocated for the technology development and infrastructure construction in this plan, which is expected to generate 50,000 new jobs every year and reduce a total of 230 million tons of greenhouse gases by 2030.

As a first step to implement the Road Map, the Korean government started a pilot program on Jeju Island in June 2009, which consists of a fully integrated smart grid system for 6,000 households, wind farms, and four distribution lines [124]. A total of $50 million public funds and $150 million private funds will be invested between 2009 and 2013. More than 100 companies from automobile, renewable, power, telecommunication, and home appliance industries participate in the program.

The People's Republic of China

Since the 1980s, China's energy consumption has been growing at an unprecedented rate due to the rapid development of its economy. Between 1990 and 2010, its electricity generation increased from 621.2 to 4206.5 Terawatt-hours (TWh) [125]. The nation's annual growth rate of electricity demand exceeded 10% in 2001 and reached 15% in 2003, exceeding the projected growth rate of 6% [126]. The country has experienced several power outages since 2005, and the shortfall in electricity has started to hurt China's economy [126]. In order to meet the increasing demand and secure economic growth, the Chinese government has increased its investment in electric infrastructure. In recent years, China also aims to make the transition from a traditional manufacturing economy to a high-tech and high value-added manufacturing and service economy. The new energy industry and transport system are two key sectors that receive government support.

In May 2009, the State Grid Corporation of China announced the plan for developing a national wide "strong and smart grid" in China by 2020 [127]. The Ultra High Voltage (UHV) transmission and highly efficient distribution transformer, which enable the expansion of transmission and distribution capacity and reduce loss are the key technologies to be developed and deployed. This plan shows that deployment of smart grids in China can be quite different from the rest of the world, especially from the developed countries. It focuses more on the transmission side than the distribution side, due to the fact that major power generation sources in China, such as coal and hydropower are located in remote areas, and there are huge disparities among power generation in different regions. Other reasons for the focus on transmission might be the relatively primitive structure at the distribution ends, and the unique asset ownership and management structure of utilities and electric markets [128].

The Amendment of the Renewable Energy Law (2009) urges utilities to develop and apply smart grid and energy storage technologies to improve grid operation and management, and facilitate the interconnection of distributed renewable energy [129]. The Chinese government also supports the construction of independent renewable micro-grids in areas not covered by power grids. Promoting the development of clean energy and smart grids is among the top priorities of the government, as noted in the 12th Five-Year Plan that became effective on March 14, 2011 [130–132].

The 12th Five-Year Plan sets separate targets for energy intensity (16% reduction by 2015), non-fossil fuel energy (11.4% of the total primary energy consumption by 2015), and carbon emissions per unit Gross Domestic Product (GDP) (17% reduction by 2015) [132]. Smart grids and clean energy technologies are seen as effective approaches to achieve these targets. New energy industry (nuclear, wind, solar, biomass, and smart grids) and new energy vehicle industry (plug-in hybrid vehicles and electric vehicles) are identified as two of the seven strategic emerging industries that would receive financial and regulatory support from the government. By 2015, several long-distance UHV transmission lines and 200,000 km of transmission lines (333 kV and above) will be constructed. The Plan also proposes the “Rural Electricity Supply Project” to upgrade the rural electric grid and meet the increasing demand of the rural areas. Some of the targets include: developing 1,000 photovoltaics demonstration villages, 200 green energy counties, 300 hydropower and rural electrification counties, and 10,000 MW small hydropower. Between 2011 and 2015, China will invest 286 billion yuan ($44 billion US dollars) in smart-grid deployment [133].

Countries are in different stages of smart-grid deployment. Smart-grid policies are often designed to address the needs and challenges faced by countries. Table 9.11 summarizes the energy and climate change targets of the five nations and regions, as well as the drivers and focuses of their smart-grid policies.

International Collaboration

The SmartGrids European Technology Platform was established in 2004, with an aim to enhance the level of coherence between the European, national, and regional efforts addressing smart grids. One important role of this platform is to cooperate with other countries, especially North America and Japan, to ensure international development paths for smart grids are complementary and consistent with the development of commercial products [134].

The IEA Implementing Agreement on Electricity Networks Analysis, Research and Development (ENARD) was developed by 14 IEA member countries in July 2006. Its mission is to provide comprehensive and unbiased information, data, and advice to key stakeholders and policymakers of the issues relating to current and anticipated developments in electricity transmission and distribution networks [135]. Some of the work programs that are closely linked to smart grids include Annex II (DG system integration), Annex III (infrastructure asset management), and Annex IV (transmission system issues). ENARD is currently focusing its activities within the IEA member countries; however, it is open to participation by non-IEA member countries, private sectors, and nongovernmental organizations.

Established in April 2010, the Global Smart Grid Federation (GSGF) brings together the key smart grid stakeholders around the world, such as US GridWise Alliance, Smart Grid Australia, Smart Grid Canada, Smart Grid Ireland, Korean Smart Grid Association, India Smart Grid Forum, and the Japan Smart Community Alliance [136].

Table 9.11 National targets, policy drivers and focuses by country

	Targets			
	Carbon reduction	Renewable energy (share of total primary energy supply)	Policy drivers	Policy focuses
USA	17% below 2005 level by 2020	Varies across states: CA – 33% by 2020; TX – 5,880 MW by 2020; NY – 29% by 2015; GA – no target	Power system reliability; Renewable energy and energy efficiency; Economic revitalization	Technical and operational standards; Smart meters; Dynamic pricing and demand response programs
EU	20% below 1990 level by 2020	20% by 2020	Renewable energy and energy efficiency; Carbon emissions reduction	Technical and operational standards; Smart meters
Japan	30% below 1990 by 2030	13% by 2030	Energy security; Carbon emissions reduction; Enhancing competitiveness of domestic industries	Smart community; Solar photovoltaic generation
Korea	30% below BAU by 2020	11% by 2030	Energy security; Carbon emissions reduction; Enhancing competitiveness of domestic industries	Smart power grid; Smart consumers; Smart transportation; Smart renewables; Smart electricity services
China	Carbon intensity: 17% below 2011 by 2015	11.4% by 2015	Economic development; Reducing power generation disparities between regions; Reducing energy/carbon intensity; Strategic economic restructuring	Ultrahigh voltage (UHV) regional transmission; Upgrading and modernizing urban and rural electric grid

Its goals are to facilitate the collaboration of governments and nongovernmental organizations, to support the development of smart-grid technologies and foster knowledge sharing. The International Smart Grid Action Network (ISGAN) was launched at the first Clean Energy Ministerial in Washington, D.C. in July 2010 to accelerate the development of smart-grid technologies at the global level. ISGAN focuses on five principal areas including policy, standards, and regulation; finance and business models; technology and systems development; user and consumer engagement; and workforce skills and knowledge [137]. It includes four projects: the global smart grid inventory, smart grid case studies, benefit-cost analyses, and toolkits and synthesis of insi^ghts for decision makers.

Future Directions

As the interoperability of technologies is essential for a large-scale and integrated deployment of smart grids, development of standards at the national and global level will be particularly important in the future. Establishment of lead agencies to coordinate efforts at various levels of governments would facilitate the standardization process, as well as address the cyber security issue across all sectors.

The electric power industry is facing tremendous opportunities and becoming increasingly important in the new emerging low-carbon economy. The costs required for a full deployment of the smart grid are large. Currently, government is still the key player in smart grid investments. This suggests the need for a policy framework that attracts private capital investment, especially from renewable project developers and communication and information technology companies.

A competitive electricity market that encourages variable business models could enhance the flexibility of the electricity system and support an increasing penetration of renewable generation technologies. Reforming the rate design mechanisms that are currently discouraging utilities' investment in advanced technologies, and ensuring that costs and benefits are shared among all stakeholders are also important future directions. Regulatory changes that remove barriers to a competitive energy market could also optimize overall operations and costs, hence increasing the net social benefits from smart grids.

As the deployment of smart grids progresses, demand response and DG may significantly reduce peak demand and make some generation facilities redundant. This requires sophisticated resource planning and CBA at the early stages of smart-grid deployment. Smart grid customer policies, such as dynamic pricing and customer protection, are highly dependent on the understanding of customer behavior. New policies should be developed based on social science studies on consumer feedback and behavior changes in response to smart grid technologies and regulations.

Collaboration on smart-grid standards and experience sharing of demonstration projects can reduce repetition and overlap in smart-grid deployment efforts. Sharing best practices can be particularly beneficial to those developing countries, where electricity infrastructure is expanding rapidly.

Conclusion

This entry underscores the novelty of emerging smart-grid policies. Along with the recent introduction of smart-grid technologies has emerged a new generation of regulations and fiscal policies to ensure that the public's interests are protected.

Access to real-time metered data is illustrative of the new issues requiring public regulation. States are beginning to set requirements regarding data security and privacy of smart meters. Texas, for example, has determined that all meter data, including data used to calculate charges for service, historical load data, and any other proprietary customer information, will belong to a customer; however, customers can allow retail electric providers to access the data under rules and charges established by the Public Utility Commission of Texas.

The ownership of renewable energy credits from customer-owned renewable facilities is another issue that is only now being clarified. The issue is important because RECs have significant economic value, and clear rules and regulations regarding their ownership could help reduce confusion and uncertainties associated with smart-grid investment. This policy issue is also contentious as it involves the design and consideration of several policy regimes, including renewable electricity standards, net metering, interconnection policies, and utility subsidies for renewable projects.

As is typical of emerging policies designed to address issues associated with technological innovations, there is great variability in the goals and the design of smart-grid policies.

- For example, while most states have net metering and interconnection standards, the specifics of these policies vary widely. Due to different preferences in promoting renewable technologies, eligible technologies and customer types vary across net metering and interconnection standards. The application and evaluation procedures for net metering and interconnection also reflect variations in grid safety and reliability concerns.
- Numerous different types of dynamic pricing rates have emerged over the past decade. As might be expected, different pricing regimes have gained prominence in different market segments. Most often, pilot projects have been first launched by large industrial customers, followed by commercial and large nonresidential customers. Variability among dynamic pricing rates also reflects the differences in the policy goals of cost recovery and demand response programs. In general, opt-out options and bill stabilization measures are provided for customer protection. Outreach and education activities are often conducted to increase public awareness of dynamic rates.
- There also is a wide array of policies to support DG-especially renewables. (More limited efforts have addressed the deployment of fuel cells and CHP systems.) Both regulatory policies and financial incentives are widely used to support DG investments. For example, 29 states have implemented a renewable electricity standard [20]. Financial incentive range from FITs to production tax credits, investment tax credits, and loans. To date, 34 states provide loan programs and 24 states provide tax credits for renewables [20].

Despite this wide-ranging policy variability, some policy principles are emerging:

- Cost estimation and allocation are critical, as they could facilitate investment in new smart grid infrastructures. Policies have also been designed to set up cost-sharing rules between the private and public sector, and sometimes, costs are allocated to all customers that benefit from the project. Government subsidies are often used to constrain interconnection costs to affordable levels. For instance, eligible customers for net metering in California are exempted from fees charged by the government, and pay only the costs associated with their interconnection facilities.

- CBA and evaluation metrics are becoming essential, and some government agencies are beginning to require the collection of such information. In some cases, government agencies will invest in smart metering technologies and will subsidize smart-grid investments only if planning and evaluation data show that the subsidies generate more benefits than costs.

Evidence from the past decade suggests that the rapid and widespread deployment of smart-grid technologies will not occur without supporting policies. This review of emerging smart-grid policies in the United States, European Union, Japan, Korea, and China suggests that considerable progress has been made to develop effective policy frameworks. Nevertheless, further advances are needed to harmonize policies across nations, states, and localities, and to learn from recent experiences with this new generation of electric grid technologies [138].

Bibliography

Primary Literature

1. The European Smart Grid Task Force (2010) Task Force Smart Grids – vision and work programme
2. U.S. Department of Energy (2008) Metrics for measuring progress toward implementation of the smart grid: results of the breakout session discussions at the Smart Grid Implementation Workshop, Washington, DC
3. The Electricity Advisory Committee (2008) Smart grid: enabler of the new energy economy, U.S. Department of Energy, Washington, DC
4. U.S. Department of Energy (2008) The smart grid: an introduction. Washington, DC
5. Kurita A, Sakurai T (1988) The power system failure on 23 July 1987 in Tokyo. Paper presented at the 27th IEEE Conference on Decision and Control, Austin, TX
6. U.S.-Canada Power System Outage Task Force (2004) Final report on the 14 August 2003 blackout in the United States and Canada: causes and recommendations. U.S. Department of Energy/Ministry of Natural Resources, Washington, DC; Ottawa, Canada
7. The White House (2006) The federal response to hurricane Katrina: lessons learned. http://library.stmarytx.edu/acadlib/edocs/katrinawh.pdf
8. U.S. Department of Energy (2009) Smart grid system report. Washington, DC
9. National Energy Technology Laboratory (2007) The NETL modern grid initiative powering our 21st-century economy: barriers to achieving the modern grid. U.S. Department of Energy, Washington, DC
10. Brown A, Salter R (2010) Smart grid issues in state law and regulation. Galvin Electricity Initiative
11. International Energy Agency (2010) Energy technology perspectives 2010. OECD/IEA, Paris
12. The Brattle Group, Freeman Sullivan & Co. and Global Energy Partners, LLC (2009) A national assessment of demand response potential. Federal energy regulatory commission staff report. Federal Energy Regulatory Commission, Washington, DC

13. Tseng P (2007) Modeling regional electricity generation. U.S. Energy Information Administration, Washington, DC
14. U.S. Energy Information Administration (2010) International energy outlook 2010. Washington, DC
15. U.S. Energy Information Administration (2011) Emissions of greenhouse gases in the U.S. Retrieved 23 June 2011, from http://www.eia.gov/environment/emissions/ghg_report/ghg_overview.cfm
16. U.S. Energy Information Administration (2010) Electric power industry 2009: year in review. Retrieved 23 June 2011, from http://www.eia.gov/cneaf/electricity/epa/epa_sum.html
17. California Public Utilities Commission (2011) Net Surplus Compensation. Retrieved 21 June 2011, from http://www.cpuc.ca.gov/PUC/energy/DistGen/netsurplus.htm
18. California Public Utilities Commission Energy Division (2005) Update on determining the costs and benefits of California's Net Metering Program as required by Assembly Bill 58
19. Public Law 109–58: Energy Policy Act of 2005. (119 Stat. 594; Date: 8/8/2005). Text from: United States Public Laws. Available from: ProQuest® Congressional; Accessed 23 May 2011
20. Database of State Incentives for Renewables & Efficiency (2011) Summary maps. Retrieved 20 June 2011, from http://www.dsireusa.org/summarymaps/index.cfm?ee=1&RE=1
21. Doris E, Busche S et al (2009) Net Metering Policy Development in Minnesota: Overview of Trends in Nationwide Policy Development and Implications of Increasing the Eligible System Size Cap. National Renewable Energy Laboratory, Golden, CO
22. Federal Energy Regulatory Commission (2006) Generator Interconnection. Retrieved 21 June 2011, from http://www.ferc.gov/industries/electric/indus-act/gi.asp
23. National Association of Regulatory Utility Commissioners (2003) Model interconnection procedures and agreement for small distributed generation resources. U.S. Dept. of Energy, Washington, DC
24. Institute of Electrical and Electronic Engineers Standards Association (2010) 1547 series of interconnection standards. Retrieved 21 June 2011, from http://grouper.ieee.org/groups/scc21/dr_shared/
25. Brown MA, Chandler J et al (2009) Making homes part of the climate solution: policy options to promote energy efficiency. Oak Ridge National Laboratory, Oak Ridge, TN
26. Federal Energy Regulatory Commission (2011) Assessment of demand response and advanced metering staff report. Washington, DC
27. Borenstein S, Jaske M et al (2002) Dynamic pricing, advanced metering and demand response in electricity markets. The Center for the Study of Energy Markets (CSEM) working paper series. University of California Energy Institute, Berkeley, CA
28. Faruqui A, Hledik R (2009) Transitioning to dynamic pricing. The Brattle Group, San Francisco, CA
29. Faruqui A, Sergici S (2009) Household response to dynamic pricing of electricity – a survey of the experimental evidence. The Brattle Group, San Francisco, CA
30. Faruqui A, Palmer J (2011) Dynamic pricing of electricity and its discontents. The Brattle Group, San Francisco, CA
31. Faruqui A, Hledik R et al (2007) The power of five percent: how dynamic pricing can save $35 billion in electricity costs. The Brattle Group, San Francisco, CA
32. Renewable Energy Policy Network for the 21st Century (REN21) (2011) Renewables 2010 global status report. REN21 Secretariat, Paris
33. Couture TD, Cory K et al (2010) A policymaker's guide to feed-in tariff policy design. National Renewable Energy Laboratory, U.S. Department of Energy, Golden, CO
34. DB Climate Change Advisors (2010) GET FiT program: global energy transfer feed-in tariffs for developing countries, Deutsche Bank Group
35. KEMA (2009) Electricity storage: policy issues. Retrieved 13 Jul 2011, from http://www.kema.com/Images/KEMA%20Energy%20Storage%20Policy%20Briefing.pdf

36. Executive Office of the President of the United States (2011) A policy framework for the 21st century grid: enabling our secure energy future. Executive Office of the President of the United States, Washington, DC
37. Public Law 110–140: Energy Independence and Security Act of 2007. (121 Stat. 1492; Date: 12/19/2007). Text from: United States Public Laws. Available from: ProQuest® Congressional; Accessed 3 June 2011
38. Public Law 111–5: American Recovery and Reinvestment Act of 2009. (123 Stat. 115; Date: 02/17/2009). Text from: United States Public Laws. Available from: ProQuest® Congressional; Accessed 6 June 2011
39. U. S. Department of Energy (2011) American Recovery & Reinvestment Act – Recovery Act Overview. Retrieved 21 June 2011, from http://www.oe.energy.gov/american_recovery_reinvestment_act.htm
40. California Public Utilities Commission (1995) California Public Utilities Code Section 2827
41. The Public Utilities Commission of the State of California (1999) Order instituting rulemaking into distributed generation
42. California Public Utilities Commission (2006) Rule 21 model rule draft to implement D.05-08-013
43. California Public Utilities Commission (2004) Administrative law judge and assigned commissioner's ruling adopting a business case analysis framework for advanced metering infrastructure. California Public Utilities Commission. Rulemaking 02-06-001
44. California Public Utilities Commission (2006) Final opinion authorizing Pacific Gas And Electric Company to deploy advanced metering infrastructure. Decision 06-07-027
45. California Public Utilities Commission (2009) Decision on Pacific Gas and Electric Company's Proposed Upgrade to the Smart Meter Program. Decision 09-03-026
46. California Public Utilities Commission (2007) Opinion approving settlement on San Diego Gas & Electric Company's advanced metering infrastructure project. Decision 07-04-043
47. California Public Utilities Commission (2008) Decision approving settlement on Southern California Edison Company advanced metering infrastructure deployment. Decision 08-09-039
48. California Public Utilities Commission (2009) An act to add Chapter 4 (commencing with Section 8360) to Division 4.1 of the Public Utilities Code, relating to electricity. Senate Bill No. 17
49. California Public Utilities Commission (2010) Decision adopting requirements for smart grid deployment plans pursuant to Senate Bill 17 (PADILLA), Chapter 327, Statutes of 2009. Decision 10-06-047
50. California Public Utilities Commission (2010) An act to add Chapter 5 (commencing with Section 8380) to Division 4.1 of, and to repeal Section 393 of, the Public Utilities Code, relating to public utilities. SB 1476
51. California Public Utilities Commission (2005) Decision closing this rulemaking and identifying future activities related to demand response. Decision 05-11-009
52. California Public Utilities Commission (2006) Decision adopting default critical peak pricing for 2007. Decision 06-05-038
53. California Public Utilities Commission (2010) Decision on peak day pricing for Pacific Gas and Electric Company. Decision 10-02-032
54. Southern California Edison (2010) Demand Response Programs. Retrieved 27 June 2011, from http://asset.sce.com/Documents/Shared/100818_Demand_Response_Program_ Guide.pdf
55. California Public Utilities Commission (2010) An act to amend Section 9620 of, and to add Chapter 7.7 (commencing with Section 2835) to Part 2 of Division 1 of, the Public Utilities Code, relating to energy. AB 2514
56. California Public Utilities Commission (2005) Opinion clarifying participation of renewable distributed generation in the renewable portfolio standards program. Decision 05-05-011
57. California Public Utilities Commission (2007) Opinion adopting methods to determine the renewable energy credits from renewable distributed generation. Decision 07-01-018

58. California Public Utilities Commission (2001) Interim Opinion: Implementation of Public Utlities Code Section 399.15(b), Paragraphs 4–7; load control and distributed generation initiatives. Decision 01-03-073
59. California Public Utilities Commission (2011) Assigned commissioner's ruling directing temporary suspension of accepting customer reservation requests under the self-generation incentive program. In: Proceeding R10-05-004, San Francisco
60. Brown MA, Gumerman E, Baek Y, Wang J, Morris C, Wang Yu (2011) Renewable energy in the South. Southeast Energy Efficiency Alliance, Atlanta, GA. Retrieved 29 June 2011, from http://www.seealliance.org/PDFs/RENEWABLE%20ENERGY%20IN%20THE%20SOUTH.pdf
61. Georgia General Assembly (2001) The Georgia Cogeneration and Distributed Generation Act of 2001. Senate Bill 93
62. Georgia Power (2011) Electric service tariff: renewable and nonrenewable resources schedule: RNR-7. Retrieved 29 June 2011, from http://www.georgiapower.com/pricing/pdf/11.10_RNR-7.pdf
63. Georgia Power (2011) Your meter is about to get smarter. Retrieved 29 June 2011, from http://www.georgiapower.com/residential/smartmeter.asp
64. Charles J, Black Energy Economics (2011) Dynamic Pricing Evaluation for Washington. National Association of Regulatory Utility Commissioners (NARUC) Grants & Research Department
65. Georgia Power (2011) Business pricing – Georgia power. Retrieved 29 June 2011, from http://georgiapower.com/pricing/gpc_rates.asp
66. State of New York Public Service Commission (1997). New York Consolidated Laws, Public Service Law, Article 4. Provisions Relating to Gas and Electrical Corporations; Regulation of Price of Gas and Electricity. NY CLS Pub Ser § 66-j & 66-l
67. State of New York Public Service Commission (1999) Opinion and oder adopting standard interconnection requirements for distributed generation units. Case 94-E-0952
68. New York State Public Service Commission (2010) New York state standardized interconnection requirements and application process for new distributed generators 2 MW or less connected in parallel with utility distribution systems
69. State of New York Public Service Commission (1997) Opinion and order establishing regulatory policies for competitive metering. Opinion No. 97-13.Case 94-E-0952
70. State of New York Public Service Commission (2006) Order relating to electric and gas metering services. Case 94-E-0952, Case 00-E-0165, Case 02-M-0514
71. State of New York Public Service Commission (2005) Order instituting further proceedings and requiring the filling of draft tariffs. Case 03-E-0641
72. State of New York Public Service Commission (2006) Order denying petitions for rehearing and clarification in part and adopting mandatory hourly pricing requirements. Case 03-E-0641
73. Consolidated Edison Company of New York, I (2009) Mandatory hourly pricing (MHP) program. Retrieved 1 Jul 2011, from http://www.coned.com/escos/news/ESCONewsletters/2009/ESCO%20Newsletter_2009-23.pdf
74. State of New York Public Service Commission (2011) CASE 09-E-0717 proceeding on motion of the commission as to the rates, charges, rules and regulation of rochester gas and electric corporation for electric service: plan for implementation of expansion of mandatory hourly pricing
75. Public Utility Commission of Texas (2008) Chapter 25. Substantive rules applicable to electric service providers – metering for distributed renewable generation. § 25.213
76. Public Utility Commission of Texas (2009). Chapter 25. Substantive rules applicable to electric service providers – arrangements between qualifying facilities and electric utilities. §25.242 (h)
77. Austin Energy (2010) Distributed generation from renewable resources rider. Retrieved 13 Jul 2011, from http://www.austinenergy.com/About%20Us/Rates/distributedGenerationFromRenewa bleSources.htm

78. Public Utility Commission of Texas (2001) Chapter 25. Substantive rules applicable to electric service providers – §25.211 interconnection of on-site distributed generation (DG). §25.211
79. Public Utility Commission of Texas (1999) Chapter 25. Substantive Rules applicable to electric service providers – §25.212 Technical requirements for interconnection and parallel operation of on-site distributed generation. §25.212
80. Public Utility Commission of Texas (2002) Distributed generation interconnection manual
81. Public Utility Commission of Texas (2005) An act relating to energy-saving measures that reduce the emission of air contaminants. H.B. No. 2129
82. Public Utility Commission of Texas (2007) An act relating to energy demand, energy load, energy efficiency incentives, energy programs, and energy performance measures. H.B. No. 3693
83. Public Utility Commission of Texas (2010) Report to the 82nd Texas legislature: a report on advanced metering as required by House Bill 2129, Austin
84. Smart Meter Texas (2011) Frequently Asked Questions. Retrieved 28 June 2011, from https://www.smartmetertexas.com/CAP/public/learn_more/learn_more_ faq.html#a2
85. Commission of the European Communities (2005) Green paper on energy efficiency or doing more with less. COM(2005) 265 final, Brussels
86. Commission of the European Communities (2006) Green paper: a european strategy for sustainable, competitive and secure energy. COM(2006) 105 final, Brussels
87. The European Parliament and the Council of the European Union (2001) Directive 2011/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market. OJ L 283/33, Official Journal of the European Communities
88. The European Parliament and the Council of the European Union (2003) Directive 2003/54/EC of the European Parliament and of the Council of 26June 2003concerning common rules for the internal market in electricity and repealing Directive 96/92/EC.OJ L 176/37, Official Journal of the European Communities
89. The European Parliament and the Council of the European Union (2006) Directive 2006/32/EC of the European Parliament and of the Council on energy end-use efficiency and energy services and repealing Council Directive 93/76/EEC. The European Parliament and the Council of the European Union, Official Journal of the European Union. OJ L 114/64, Official Journal of the European Communities
90. The European Parliament and the Council of the European Union (2009) Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC. The European Parliament and the Council of the European Union, Official Journal of the European Union. OJ L211/55, Official Journal of the European Communities
91. General Secretariat of the Council (2011) European Council 4 February 2011-conclusions, Brussels
92. European Commission (2011) Communication from the Commission to the European Parliament, The Council, The European Economic and Social Committee and the Committee of the Regions: smart grids: from innovation to deployment. COM (2011) 202 Final
93. European Commission (2009) Standardization mandate to CEN, CENELEC and ETSI in the field of measuring instruments for the development of an open architecture for utility meters involving communication protocols enabling interoperability, M/441 EN. European Commission, Brussels
94. European Commission (2010) Standardization Mandate to CEN, CENELEC and ETSI concerning the charging of electric vehicles, M/468 EN. European Commission, Brussels
95. European Commission (2011) Standardization mandate to European Standardization Organizations (ESOs) to support European Smart Grid Deployment, M/490. European Commission-Directorate General for Energy, Brussels
96. European Commission (2011) Understand FP7. Retrieved 5 Jul 2011, from http://cordis.europa.eu/fp7/faq_en.html

97. The Commission of the European Communities (2009) Commission recommendation of 9.10.2009 on mobilising information and communications technologies to facilitate the transition to an energy-efficient, low-carbon economy. Sec(2009)1315, Sec(2009)1316. Commission of the European Communities, Brussels
98. European Commission (2011) ICT for sustainable growth. Retrieved 6 June 2011, from http://cordis.europa.eu/fp7/ict/sustainable-growth/energy_en.html#smartgrids
99. ADDRESS (2011) Towards the smart grids of the future. Retrieved 5 Jul 2011, from http://www.addressfp7.org/
100. Italian Ministry for Economic Development (2010) Italian National Renewable Energy Action Plan
101. European Commission (2007) Development Programmes -Operational Programme Renewable Energy and Energy Efficiency. Retrieved 5 Jul 2011, from http://ec.europa.eu/regional_policy/country/prordn/details_new.cfm?gv_PAY=BG&gv_reg=ALL&gv_PGM=1040&gv_defL=4&LAN=7
102. International Energy Agency (2011) Technology roadmap – smart grids. OECD/IEA, Paris
103. Enel (2011) Smart metering system. Retrieved 5 Jul 2011, from http://www.enel.com/en-GB/innovation/project_technology/zero_emission_life/smart_networks/smart_meters.aspx?it=0
104. Enel Distribuzione (2011) E-mobility. Retrieved 5 Jul 2011, from http://www.enel.com/en-GB/innovation/project_technology/zero_emission_life/mobile_sustainability/e-mobility.aspx?it=-2
105. Redpoint Energy and Trilemma UK (2010) Electricity market reform analysis of policy options
106. HM Government (2011) Carbon plan. Department of Energy and Climate Change
107. UK Parliament (2008) Energy Act 2008
108. The UK Parliament (2011) Energy Bill [HL] 2010–11. Retrieved 5 Jul 2011, from http://services.parliament.uk/bills/2010-11/energyhl.html
109. Department of Energy and Climate Change and Office of the Gas and Electricity Markets (2010) Smart metering implementation programme: prospectus
110. Department of Energy and Climate Change and Office of the Gas and Electricity Markets (2011) Smart metering implementation programme: response to prospectus consultation
111. National Audit Office (2011) Department of Energy and Climate Change: preparations for the roll-out of smart meters, London
112. Nakanishi H (2010) Japan's Approaches to Smart Community. Technical regulations, standards and conformity assessment policy division. Ministry of Economy, Trade and Industry, Japan
113. Ministry of Economy, Trade and Industry, Japan (2010) The strategic energy plan of Japan. Retrieved 6 Jul 2011, from http://www.meti.go.jp/english/press/data/pdf/20100618_08a.pdf
114. Ito S (2009) Japan's initiative on smart grid – a proposal of nature grid. Information Economy Division, Ministry of Economy Trade and Industry (METI)
115. Ministry of Economy, Trade and Industry, Japan (2010) Announcement of master plans for the demonstration of next-generation energy and social systems. Retrieved 6 Jul 2011, from http://www.meti.go.jp/english/press/data/20100811_01.html
116. New Energy and Industrial Technology Development Organization (2011) NEDO projects – news list (2011). Retrieved 9 June 2011, from http://www.nedo.go.jp/english/archives2011_index.html
117. Japan Smart Community Alliance (2010) What's JSCA. Retrieved 5 Jul 2011, from https://www.smart-japan.org/english/tabid/103/Default.aspx
118. Yogasingam A (2009) Toshiba partners with two companies to commercialize smart meters, EE Times
119. Ministry of Economy, Trade and Industry, Japan (2009) The new purchase system for photovoltaic electricity will be launched 1 Nov 2009. Retrieved 7 Jul 2011, from http://www.meti.go.jp/english/press/data/20090831_02.html
120. Bae H, Wheelock C (2010) Smart grid in Korea-smart power grid, consumers, transportation, renewable energy, and electricity service: market analysis and forecasts, PikeResearch

121. United Nations Environment Programme (UNEP) (2010) Overview of the Republic of Korea's National Strategy for Green Growth
122. Ministry of Knowledge Economy and Korea Smart Grid Institute (2005) 10 Power IT Projects. Retrieved 7 Jul 2011, from http://www.smartgrid.or.kr/Ebook/10POWER_IT_PROJECTS.PDF
123. Ministry of Knowledge Economy and Korea Smart Grid Institute (2010) Korea's smart grid roadmap 2030: laying the foundation for low carbon, green growth by 2030. Retrieved 7 Jul 2011, from http://www.greentechmedia.com/images/wysiwyg/News/SG-Road-Map.pdf
124. Korea Smart Grid Institute (2010) Korea's Jeju smart grid test-bed overview. Retrieved 9 June 2011, from http://www.smartgrid.or.kr/10eng3-1.php
125. BP (2011) BP Statistical Review of World Energy June 2011. Retrieved 12 Jul 2011, from http://www.bp.com/sectionbodycopy.do?categoryId=7500&contentId=7068481
126. Austin A (2005) Energy and power in China: domestic regulation and foreign policy. The Foregin Policy Centre, London
127. State Grid Corporation of China (2011) The acceleration of smart grids. Retrieved 5 Jul 2011, from http://www.sgcc.com.cn/ztzl/newzndw/cyfz/03/243983.shtml
128. Li J (2009) From strong to smart: the Chinese smart grid and its relation with the globe, Asia energy platform
129. The National People's Congress Standing Committee (2009) Renewable Energy Law of the People's Republic of China (Amended)
130. Xinhua News Agency (2010) Report on the work of the government of China 2010, Beijing
131. Xinhua News Agency (2011) Report on the work of the government of China 2011, Beijing
132. Xinhua News Agency (2011) The 12th five-year plan for National Economy and Social Development of the People's Republic of China, Beijing. Retrieved 2 Jul 2011, from http://www.gov.cn/2011lh/content_1825838.htm
133. Smart Grid China Summit (2011) China's leading smart grid gathering for interaction and knowledge sharing. Retrieved 10 Jul 2011, from http://www.smartgridchinasummit.com/smartgrid/
134. Directorate-General for Research (2006) European smart grids technology platform -vision and strategy for Europe's electricity networks of the future, Brussels
135. Baker JN (2011) International energy agency implementing agreement on electricity networks analysis, research and development: programme of work. International Energy Agency
136. Global Smart Grid Federation (2011) About the global smart grid federation. Retrieved 1 Jul 2011, from http://www.globalsmartgridfederation.org/about.html
137. The International Smart Grid Action Network (2011) Fact sheet: international smart grid action network. Retrieved 2 Jul 2011, from http://www.cleanenergyministerial.org/pdfs/factsheets/CEM2_Fact_Sheet_ISGAN_07April2011.pdf
138. Brown MA, Sovacool BK (2011) Climate change and global energy security: technology and policy options. MIT Press, Cambridge, MS

Books and Reviews

Gellings CW (2009) The smart grid: enabling energy efficiency and demand response. Fairmont, Lilburn, GA
Heffner G (2011) Smart grid – smart customer policy needs. An IEA paper submitted to the Energy Efficiency Working Party. International Energy Agency, Paris
Willrich M (2009) Electricity transmission policy for America: enabling a smart grid, end-to-end. Energy innovation working paper series, Massachusetts Institute of Technology

Index

M.M. Begovic (ed.), *Electrical Transmission Systems and Smart Grids: Selected Entries from the Encyclopedia of Sustainability Science and Technology*, DOI 10.1007/978-1-4614-5830-2, © Springer Science+Business Media New York 2013