3 Smart Energy Resources: Supply and Demand

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Planning and operating the grid is a complex process to ensure the dynamic balance of the supply and demand of the electrical grid. Utilities must ensure there is sufficient margin of supply for any contingencies in the generation supply as well as the changes in the transmission and distribution grid configuration. Utilities must schedule and dispatch generation sources to minimize costs and maximize efficiency and security of supply.

In the past, the load on the grid depended on individual consumer energy usage patterns. Utilities had very little visibility of loading patterns at the distribution feeder or individual consumer level. As utilities deploy more smart meters and additional monitoring devices further down into the distribution network, they will have a greater understanding of the system load dynamics and can better plan and manage generation and grid assets. Utilities can now also implement more advanced technologies to help balance the supply-demand equation, such as adding distributed generation to the grid, and changing consumer load behaviors through energy pricing options or real-time pricing signals.

Smart Energy Resources is the term used in this book to define the new set of resources available to utilities to balance the supply-demand equation—renewable generation, energy storage, and consumer demand management. The challenge is not only the long-term planning and implementation of the resources, but also the real-time operation and management of the supply-demand equation, while operating in an open access market, and with generation resources that are more distributed further down on the distribution grid.

### 3.1 THE ENERGY SUPPLY SIDE OF THE EQUATION

In the early beginnings of the electric industry, power generation was comprised of a series of small generators installed at large customer facilities, towns, and cities. As the demand for reliable electricity supply increased and the industry developed, the need for larger generators and interconnected power systems grew as well. Three basic types of power generation are used meet the varying characteristics of electric loads: baseload units, intermediate units, and peak load units. These three categories of power generation largely reflect trade-offs between capital cost and operating cost, where each type of generator serves a different role, and in combination, they lower total costs and meet reliability needs.

**Baseload units:** Baseload generation capacity represents generation that essentially operates continuously at the same level. Baseload generation typically includes nuclear, coal, or very efficient gas-fired plants. The generation from these plants is used during all hours of the year. Note that in some regions, hydro may also be used to supply base load when it is in ample supply.
Intermediate or responsive and load following units: These generation plants are generally more responsive to load changes than baseload units and are intended to ramp (up and down) to supply varying load. Many units in this group may be considered load following units. Moving up the load duration curve from baseload, these units help the grid supply electricity load demanded by consumers on the timescale of minutes or hours, and some of these plants can respond to load changes in seconds. Responsive and load-following generation capacity is often provided by combined-cycle natural gas power plants and hydro generation. Intermediate generation units are not always needed on the grid, such as at night, and when they are, it is not always at full capacity.

Utilities or system operators pay a premium for intermediate and responsive load following power over baseload units because such plants can be quickly dispatched as needed at a relatively low variable cost. As they must be flexible enough to be ramped up and down as a regular part of operations, the operating efficiency of these plants is usually less than baseload generation, which translates to somewhat higher variable costs. These price premiums help compensate plant owners for the reduced production that occurs, to make up for the fact that they do not generate power for as many hours as baseload plants. In exchange for this higher cost, intermediate plant owners make assurances that they will be available to provide power when needed.

Peaking units: Peaking units help utilities serve loads during the hours of highest demand. For most utilities, peak load only occurs for a few hours in the year, and is typically much greater than the total average base load. For example, it may be the case that ~20% of the total system generation capacity must be available to serve <10% of the hours in the year. As with responsive and load following units, peaking units operate even fewer hours per year, and the owners of these plants must receive premium payments to stay profitable.

The pattern of generation usage and the types of generation available determines the economic and environmental cost of generation systems. Less efficient fossil fuel units tend to emit greater pollution and are more expensive to operate, but they are responsive when needed. Responsive, load following, and peaking units many times sit idle until the few hours per day or per year they are needed. While utilities and grid operators would undoubtedly prefer not to have to pay for these expensive units, they represent the only supply-side tool to meet large spikes in demand to respond to contingencies that occur with other plants and the T&D (transmission and distribution) system.

Because utilities and system operators have minimal influence and control on the load or demand side of the grid, they are required to build out redundant supply-side capacity to ensure a high level of reliability. With significant peak demand by consumers, utilities must procure generation portfolios that are largely overbuilt. As a result, most power systems have low-capacity factors. To illustrate, in 2006 in the ISO-NE region (Independent Systems Operator-New England) of the United States, 25% of the entire generation fleet ran 2.92% of the time or less, and 15% of the entire generation fleet ran 0.90% of the time or less. These calculations exclude the idle generation that was kept available to meet the required 10% planning reserve margin [1]. Put another way, 20% of ISO-NE’s total generation capacity was used to deliver only 0.34% of the annual energy use, and 30% of its total generation capacity was used to deliver only 1.63% of annual energy use [2]. In most other parts of the United States, generation asset utilization is similarly low, and, on average, the entire U.S. generation fleet operates at a 50% capacity factor.

These illustrations show that building generation to meet the highest peak loads is quite cost-inefficient, and much of the generation fleet is unused over many hours of the year. In other words, the system is significantly overbuilt to compensate for varying loads, and these generation units must still be paid for by the utility or power market, and ultimately by consumers. The electric energy payments are for electricity produced ($/MWh) in an hour. Capacity payments are for the availability to respond as needed to major changes in load or generation on the grid and provide a specific level of output ($/MW). Baseload units are considered to provide energy supply. Responsive and load-following units provide energy and capacity and, thus, in some markets get paid for both.
power industry has followed this paradigm for many years. However, smart grid technology is now able to provide efficient alternatives to supply-side only solutions.

Large-scale centralized generation dominated the power industry for decades until growing environmental and socioeconomic concerns and rising interest in power system efficiency improvement favored the construction of smaller-scale generation facilities (particularly those of renewable nature) closer to customer loads over the construction of large power plants and long transmission lines. This trend, prompted, for instance, by the Public Utilities Regulatory Policy Act (PURPA) of 1978 or the Energy Policy Act of 1992, has led to the emergence of the distributed energy resource (DER). DER technologies are smaller capacity power generation and storage resources typically located close to the load they serve, either owned by the utility, a third party, or by the consumer. DERs may be located “behind-the-meter” on a customer’s premises where they may supply all or a portion of the customer’s load, or DERs may be located on the main primary distribution circuit as a “community-level” energy supply. DERs may also be capable of injecting power into the grid, or into a nonutility local network in parallel with the utility grid. DERs typically use renewable energy sources, combined heat and power (CHP) or cogeneration systems, wind turbines, micro gas turbines, backup diesel generators, batteries, fuel cells, or a combination of technologies, e.g., PV and battery storage. DG (distributed generation) is a term that is commonly used to refer to generation only (not storage). There are many potential configurations for DERs, from basic backup generation all the way up to a full microgrid.

Providing backup has been the most basic and prevalent application of DERs in the past. Backup generators are usually small diesel generators designated as support for specific loads. Under this configuration, the grid has primary responsibility for providing power; the backup generator only operates when the grid has been compromised or demand exceeds the ratings of the grid equipment that serves the load. Backup generation can be owned by the utility or by the consumer (private). The problem with backup generations is that they lead to what is called low asset utilization, since the backup generators do not run unless the grid is unavailable. Because they have relatively low asset utilization rates, the cost of delivered energy over the lifetime of backup generators tends to be very high. Those high costs drive private backup generator customers to opt for smaller backup generators that are generally not large enough to pick up the entire load. When an outage occurs, most of the load must be dropped with only critical loads, such as emergency lighting, remaining active. Furthermore, these critical loads are often on a separate circuit, meaning that even if the backup generators were large enough, they would not be able to power regular loads. Utilities follow similar logic, putting backup generators only on circuits where critical operations, such as hospitals or high-tech businesses, are located. In many situations, it would be helpful to the system to have the DER operating much of the time. But without embedded intelligence in these resources, they cannot be effectively integrated into the rest of the system. In some cases, private backup generators can support the grid when there is a requirement to do so or there are opportunities in the wholesale market.

The last two decades have seen the resurgence of grid-connected DER, either independent power producers (IPPs), privately owned DER, or utility-owned DER. This DER application has the objective of supplying service to the grid or directly to customers in a continuous fashion, that is, in the same way as conventional centralized generators. The main difference with this approach is the location (close to the loads), installed capacity (smaller size), and type or lack of ancillary services (e.g., voltage regulation and frequency regulation) that the DER provides. Furthermore, it requires interconnection with the distribution system using synchronous, induction, and electronically coupled generators. This can represent a significant challenge since distribution systems have historically designed to be operated in a radial fashion, without any special considerations for DG, and it may lead to impacts that could affect the operation of both distribution systems and DG, particularly for intermittent DG, such as solar PV and wind. Smart grid technologies can play a significant role in facilitating the integration of DG and mitigating impacts on the distribution grid.

More recently, the increasing deployment of large scale wind and solar plants is also changing the equation on the supply side. Indeed, in places like Australia, the progressive deployment of wind and solar utility plants has resulted in a number of older coal and gas plants being retired
or mothballed since they are no longer profitable. This change in the supply mix is changing the characteristics of the supply side of the equation since solar and wind, although variable in nature, assume the role of variable non-dispatchable baseload. This changes the requirements for the balance of the generation fleet, increasing the value of generation that is flexible and can respond to load changes quickly, e.g., batteries, or fast acting open cycle gas plants that can ramp up within 15 min. This opens an additional opportunity for demand side flexibility, but also paves the way for a faster evolution towards the smarter grid so that DER and flexible loads can become more prominent actors in the grid space.

3.2 THE CONSUMER DEMAND SIDE OF THE EQUATION

Utilities and power providers have, for the most part, found that management of consumer loads results in lower financial returns. To utilities and other grid operators, consumer loads must be met regardless of how much power is demanded. Utilities and grid operators have assumed complete responsibility for meeting consumer demand, regardless of the pattern of the demand or how much it costs to provide the electricity.

However, the deployment of variable renewables, both at utility-scale as well as at DER customer-scale, is a challenge to meet this consumer demand, due in part by utilities having no control of what happens behind the meter, and extreme grid conditions, such as zero net load in the middle of the day, as the case forecasted for South Australia in 2026/7 [3].

There are significant pilots and research examples that indicate that consumers may be willing to change their demands in response to incentives, information, and prices. Recent studies have shown that something as simple as an in-home display that shows peak hours or peak prices can help shift consumer demand. Recent advanced technology allows appliances to automatically change power use based on the grid needs or in response to different electricity prices in ways that minimize the impact to consumers. These advances suggest that the consumer mass market can change their demand, which opens a whole new industry for Demand Side Management (DSM) technologies and services. This has resulted in the development of a cohesive set of product technologies, programs, standards, and consumer devices for consumer demand management. Measurement and validation of demand management participation by the consumer are required in addition to a means of financial settlement, both of which can be enabled by smart meters. Communication is also a key component over both the utility service area as well as within a customer premise. AMI infrastructures can provide communications to the consumer for demand management, although other communications technology options are also being explored and piloted.

Assume that consumer loads can be divided into two categories, so-called critical or nondiscretionary loads that cannot be disconnected from the grid at any time and noncritical or discretionary loads that are not significantly impacted if disconnected from the grid. Critical loads might include hospitals, critical telecommunication infrastructure, security systems, and emergency response sites. Noncritical loads might include residential customer washers and dryers, hot water heaters, decorative lights, and some part of air conditioning load. Management of discretionary loads could include dimming certain lights, reduced heating/cooling needs, and altering less critical certain business processes.

Beyond the distinction between critical and noncritical loads, it is useful to think of loads across a spectrum of values based on the customer's willingness to alter usage patterns. Consider a potential scenario where each load is prioritized compared to other loads, and the importance of each load is reflected in the price the consumer will pay to retain the service provided by that end-use device. The load (importance) ranking for every load in every house, neighborhood, or city could be put in line to receive power based on how much value it provides, rather than treating all loads as having equal importance. If each load can be controlled on or off based on the current price of electricity and the value placed on the service by the consumer, one could envision a prioritization of each load in terms of a specific electricity price level. A similar approach is to couple specific consumer
smart grid enables informed participation by customers, making it an integral part of the electric power system. With bidirectional flows of energy and coordination through communication mechanisms, a smart grid should help balance supply and demand and enhance reliability by changing how customers use and purchase electricity. These changes are expected to be the result of smarter consumer choices and shifting patterns of behavior and consumption. Enabling such choices requires new technologies, new information regarding electricity use, and new pricing and incentive programs.

Having smarter consumers allows a smart grid to add consumer demand as another manageable resource, together with power generation, grid capacity, and energy storage. From the standpoint of the consumer, system management in a smart grid environment involves making economic choices based on the variable cost of electricity, the ability to shift load, the level of economic incentives and how they affect the customer’s financials, the impacts of curtailing load (e.g., loss of comfort or impact in the business), and the ability to store or sell energy. From the standpoint of a smart grid operator, system management in a smart grid environment involves sending the price signals necessary to stimulate the right load shift or utilization of energy storage at the right time.

Consumers who are presented with a variety of options for purchasing power, consuming and producing energy are given the ability to do at least two things. First they could respond to price signals and other economic incentives to make better-informed decisions regarding when to purchase electricity, when to generate energy using DG, and whether to store and reuse it later with distributed storage. Second, consumers need to make informed investment decisions regarding more efficient and smarter appliances, equipment, and control systems.

System engineers must be able to understand and incorporate models of the devices consumers use and the patterns of their use. This knowledge doesn’t necessarily need to reside with an electric utility because other providers in the market (e.g., load aggregators, smart thermostat providers) are expected to become more pervasive in the market. However, utility system engineers will have to change their processes and models to incorporate this knowledge. The models must include all the salient features of the devices and their aggregation that support the smart grid, so planners and engineers can quantify the financial benefits and the operational impact of the smart grid on the overall electric system.

### 3.3 RENEWABLE GENERATION

#### 3.3.1 REGULATORY AND MARKET FORCES

Many countries across the world, including the United States, have developed regulations to enable integration of more renewable energy into the overall generation portfolio. These include renewable energy portfolio standards (RPS), renewable tax credits, and feed-in tariffs. In some countries, various jurisdictions have also created Renewable Energy Targets to further accelerate the move toward renewable energy. Some of these requirements for renewable energy are so aggressive that utilities are concerned about the grid performance and system operational impacts of the intermittent nature of renewable energy generation (e.g., wind and solar).

For example, in 2002, California established its RPS program, with the goal of increasing the percentage of renewable energy in the state’s electricity mix to 20% by 2017. On November 17, 2008, Governor Arnold Schwarzenegger signed Executive Order S-14-08 requiring that California utilities reach the 33% renewable goal by 2020. Achievement of a 33% by 2020 RPS would reduce generation from nonrenewable resources by 11% in 2020. This is currently the most aggressive RPS proposed by any of the U.S. states. Other state governments have similar, although at lower
penetration levels, but also aggressive RPS allocations [4]. We can also find a good example in Australia, where, for example, the state of South Australia has a target of 50% by 2025 and the state of Queensland a target of 50% by 2030.

As electric utilities prepare to meet their respective renewable regulatory requirements, it becomes evident that utilities must adapt their planning and operations practices in order to maintain high levels of service reliability and security. These initiatives require integration of significantly higher levels of renewable energy, such as wind and solar, which exhibit intermittent generation patterns. Due to the geographic location of renewable resources, much of the expected new renewable generation additions will be connected via one or two utility’s transmission systems. This presents unique challenges to these utilities as the level of intermittent renewable generation in relation to their installed system capacity reaches unprecedented and disproportionate levels.

Entities in the United States, such as CEC (Consumer Electronics Control), NERC (North American Electric Reliability Council), CAISO (California Independent Systems Operator), NYSEDA (New York State Energy Research & Development Authority), SPP (Southwest Power Pool), and CPUC (California Public Utilities Commission), have initiated and funded several studies on the integration of large levels of renewable energy, and most of these studies concluded that with 10%–15% intermittent renewable energy penetration levels, traditional planning, and operational practices will be sufficient. However, once a utility exceeds 20% penetration levels of renewable resources, it may require a change in engineering, planning, and operational practices, including the development of a smarter grid. These studies support continuing transmission and renewable integration planning studies and recommend that smart grid demonstration project installations should be conducted by the different power utilities.

The United States, and especially California, has a different set of electric system characteristics than in Europe, but there is no experience or research in Europe that would lead us to think that it is technically impossible to achieve 20%–30% intermittent penetration levels at most U.S. utilities. Long transmission distances between generation resources and load centers characterize the network in the United States and especially in the WECC region. There are now areas in Europe and Australia that are highly penetrated with intermittent renewable, especially wind generation, at higher levels of around 30%–40%.

Large-scale wind and solar generation will affect the physical operation of the grid. The areas of focus include frequency regulation, inertia, load profile following, and broader power balancing. The variability of wind and solar regimes across resource areas, the lack of correlation between wind and solar generation volatility and load volatility, and the size and location of the wind plants relative to the system in most U.S. states suggest that impacts on regulation and load profile requirement resource smoothing will be large at above 20% penetration levels [4].

The European experience taught us that there are consequences of integrating these levels of wind resources on network stability that should be addressed as wind resources reach substantial levels of penetration. A list of the major issue categories follows:

- New and in-depth focus on system planning. Steady-state and dynamic considerations are crucial.
- Accurate resource and load forecasting become highly valuable and important.
- Voltage support to manage reactive power compensation is critical to grid stability. This also includes dynamic reactive power requirements of intermittent resources.
- Evolving operating and power balancing requirements. Existing generator ramp rates must be considered in order to balance power from large-scale wind and solar generation. Grid operations must also ensure grid stability and minimize start-stop operations for load-following generators.
- Increased requirements for ancillary services. Faster ramp rates and a larger percentage of regulation services will be required, which can be supplied by responsive storage facilities. These requirements may require specific market incentives that can drive deployment.
and operation of such resources; otherwise, these services may continue to be delivered by existing plants.

- Equipment selection. Variable-speed generation (VSG) turbines and advanced solar inverters have the added advantage of independent regulation of active and reactive power. This technology is essential for large-scale renewable generation.
- Strong interconnections. Renewable generation and energy storage are, by their nature, only available in certain geographic locations. Therefore, strong interconnections make geographic integration of energy resources possible.

Technical renewable integration issues should not delay efforts to reach the renewable integration goals. However, focus has increased on planning and research to understand the needs of the system, for example, research on energy storage options.

Studies and actual operating experience indicate that it is easier to integrate wind and solar energy into a power system where other generators are available to provide balancing power and precise load-following capabilities. The greater the number of wind turbines and solar farms operating in a given area, the lower the variability in their aggregated generation. However, this variability will be strongly correlated with weather and how it impacts the various specific geographical areas where the renewable portfolio sits. High penetration of intermittent resources (>20% of generation meeting load) affects the network in the following ways [4]:

- Thermal and contingency analysis
- Short circuit
- Transient and voltage stability
- Electromagnetic transients
- Protection coordination
- Power leveling and energy balancing
- Power quality

The largest barrier to renewable integration in the United States is sufficient transmission facilities and associated cost-allocation in the region to access the renewable resources and to connect these resources to load centers. Other key barriers include environmental pressure and technical interconnection issues, such as forecasting, dispatchability, low-capacity factors, and intermittency impacts on the regulation services of renewable resources.

In the United States, the sources of the major renewable resources are remote from the load centers in California and the Midwest states. This results in the need for addition of new major transmission facilities across the country. Wind and solar renewable energy resources normally have capacity factors between 20% and 35%, compared to higher than 90% of traditional nuclear and coal generation. These low-capacity factors place an even higher burden on an already scarce transmission capacity. Identification, permitting, cost-allocation, approval, coordination with other stakeholders, engineering, and construction of these new transmission facilities are costly and time-consuming barriers.

Although energy production using renewable resources is pollution free, wind and solar plants need to be balanced with fast ramping regulation services like peak generation, hydro generation plants, or energy storage batteries. Existing regulation generation is too slow and more pollutive during ramping regulation service. The increased requirements in regulation services counteract the emission savings from these renewable resources, depending on what fuel is used to deliver the additional regulation services. Currently, the frequency regulation requirement at the CAISO is around 1% of peak load dispatch, or about 350 MW. This is currently mainly supplied by peaker (gas) generating plants and results in higher emission levels. It has been calculated that around 2% regulation would be required for integrating 20% wind and solar resources by 2010 and 4% to integrate 33% renewables by 2020 [4].
With the integration of wind and solar generation, the output of the fossil fuel plants needs to be adjusted frequently in order to cope with the fluctuations in wind and solar generation. Some power stations will be operated below their maximum output to facilitate this, and extra system balancing reserves will be needed. At high penetrations (above 20%), wind and solar energy may need to be “spilled” or curtailed because the grid cannot always utilize the excess energy.

In grids with a very high penetration of renewables, occasional season variations in renewable resources (e.g., the wind “drought” in South Australia during July 2017) may have wider generation fleet implications that require utilities to switch baseload generation fuels (from wind to gas, for example). Therefore, generation fleets have to include not only fast reacting resources, as described above, but also slow reacting resources that are able to provide inertia to minimize the effect of these types of events. This can be a technical challenge as well as a market challenge, since the generation fleet and grid will have to balance fast and slow acting generation resources, whilst being profitable, yet not dramatically increasing consumer prices.

3.3.2 TECHNOLOGIES

There are several renewable sources of electric energy (generically called renewables). The main difference between renewables and other conventional energy sources is that renewables provide energy that is cleaner with respect to pollution. Another distinguishing difference is that renewable energy sources do not deplete natural resources in the process of creating power. The third difference is that renewables are scalable to the appropriate size anywhere from single-house applications all the way up to large-scale renewables, which can supply power to thousands of homes. Some of the most common renewable energy resources are introduced in the next sections.

3.3.2.1 Solar PV

Solar PV generation has experienced a tremendous growth in recent years due to growing demand for renewable energy sources. PV represents a method of generating electric power in solar panels that are exposed to light. Power generated is based on the conversion of the energy of the sun's radiation. A solar cell that is exposed to light transfers electrons between different bands inside the material. This, in turn, results in a potential difference between two electrodes, which caused direct current (DC) to flow. There are several main PV applications, such as solar farms, building, auxiliary power supply in transportation devices, stand-alone devices, and satellites. Utilities around the world started incorporating solar farms into their generation portfolios mostly during the last decade. To incorporate solar farms into utility grids, alternating-current/direct-current (AC/DC) converters are required, as well as the associated control and protection systems. The main issue with PVs is intermittency. Since PV is a variable power source that cannot be accurately predicted, several efforts have been undertaken to increase the dispatchability of PV power. Successful approaches have included adding battery storage to store the PV energy during off-peak hours or low demand, and then discharging the batteries during peak usage periods. However, when PV is combined with other generating technologies and/or load management, the issues of intermittency may be strongly reduced. Today, solar PV represents <0.5% of total global power generation capacity. However, in some areas of the world, the penetration of PV has been increasing to much higher levels (e.g., states in Australia such as South Australia and Queensland). PV growth is currently seen in both the deployment of centralized power plants, as well as small customer-owned DG, bringing electrical challenges not only to the large transmission power systems but also at the distribution level, an area that traditionally has been “a set it and forget it” deployment of assets.

3.3.2.2 Solar Thermal

Solar thermal energy (STE) is a technology that converts solar energy into thermal energy (heat). There are three types of collector levels that are based on the temperature levels: low, medium,
and high. In practice, low-temperature collectors are placed flat to heat swimming pools or space heating, medium-temperature collectors are flat plates used for heating water or air, and high-temperature collectors are used for electric power production. Heat represents the measure of the thermal energy that an object contains, and three main factors, specific heat, mass, and temperature, define this value. Essentially, heat gain is accumulated from the sun rays hitting the surface of the object. Then, heat is transferred by either conduction or convection. Insulated thermal storage enables STE to produce electricity during the days that have no sunlight. The main downside to STE plants is the efficiency, which is a little over 30% at best for solar dish/stirling engine technology, while other technologies are far behind.

3.3.2.3 Wind
Wind power is obtained by using wind turbines to convert the energy of the wind into electricity. Wind energy is a highly desirable renewable energy source because it is clean technology that produces no greenhouse gas emissions. The main downside of wind power is its intermittency and the impact on the environment (visual, noise, and wildlife). During normal operation, all the power of the wind turbine must be utilized when it is available. If the power from the wind turbine is not used, the wind turbine output must be curtailed, or the excess power generated can be used to charge an energy storage system. Due to the intermittency or variability of the wind speed, power output from wind turbines is inconsistent. Inconsistency in power output is the main reason why wind farms cannot be used in a utility’s base-load generation portfolio without the addition of energy storage. The capacity factor of a wind power turbine ranges from 20% to 40%.

3.3.2.4 Biomass and Biogas
Dead trees, wood chips, plant or animal matter used for production of fibers, chemical, or heat all refer to biomass. Technologies associated with biomass conversion to electrical energy include releasing energy in the form of heat, or the conversion to a different form, such as combustible biogas or liquid biofuel. The downside of biomass as a fuel is its potential for increased air pollution. The biomass industry has recently experienced an upswing, and the level of electricity in the United States produced by biomass plants is around 1.4% of the total U.S. electricity supply.

3.3.2.5 Geothermal Power
Geothermal power is extracted from the earth through natural processes. There are several technologies in use today, such as binary cycle power plants, flash steam power plants, and dry steam power plants. The main issue with geothermal power is low thermal efficiency of geothermal plants, even though the capacity factor can be quite high (up to 96%). Geothermal plants can be different in size. Geothermal power is reliable and cost effective due to no fueling costs, but initial capital costs associated with deep drilling as well as earth exploration are the main deterring factors from higher penetration of geothermal resources.

3.3.2.6 Wave Power
There are two types of ocean power that can be harnessed: wave power and tidal power. Wave power is associated with the energy produced by ocean waves that are on the surface and converting that energy for the generation of electricity. Today, wave farms have been installed in Europe. Currently, this type of renewable does not have significant penetration, because it is highly unreliable, and it requires large wave energy converter to be deployed. The first such farms are expected to be a wave park in Reedsport, Oregon, and the Perth wave energy project in Western Australia. The PowerBuoy technology that will be used for this project will have modular, ocean-going buoys, and the rising and falling of the waves will cause the buoys to move, creating mechanical
energy that will be later converted to electric energy and transmitted offshore through the underwater transmission line.

3.3.2.7  **Hydro**
Hydropower plants use the energy of the moving water as the main source for producing electricity. The water fall and gravitational force of this falling water hit the blades on the rotor, which cause the rotor to turn, thus producing electricity. Most of the time, hydropower plants are built in places where there is not an abundance of water, but the water is very fast moving (like in mountainous areas), and in the valleys where there is an abundance of water, but the water is moving slowly.

3.3.2.8  **Fuel Cells**
A fuel cell uses the chemical energy of hydrogen or another fuel to cleanly and efficiently produce electricity. If hydrogen is the fuel, electricity, water, and heat are the only products. Fuel cells work like batteries, but they do not run down or need recharging. They produce electricity and heat as long as fuel is supplied. A fuel cell consists of two electrodes—a negative electrode (or anode) and a positive electrode (or cathode)—sandwiched around an electrolyte. Fuel cells can convert the chemical energy in the fuel to electrical energy with efficiencies of up to 60%.

3.3.2.9  **Tidal Power**
Tidal power converts the energy of tides into electricity. The most common tidal power technologies are tidal stream generators and tidal barrages. Tidal stream generators rotate underwater and produce electricity using the kinetic energy of tidal streams. Tidal barrage uses a dam located across a tidal estuary to produce electricity using the potential energy of water. Water flows into the barrage during high tide and then it is released during low tide while moving a set of turbines. New technologies, such as dynamic tidal power, are being discussed and evaluated; this technology is intended to take advantage of a combination of the kinetic and potential energy of tides.

3.3.3  **RENEWABLE ENERGY IN THE SMART GRID**
To integrate renewable energy generation at high penetration levels, several planning and operational guidelines should be followed. A smart grid strategy to achieve high renewable penetration should include [4].

- Generation mix to utilize different complementary resources
- Advanced smart grid transmission facilities, including fast responsive energy storage, Flexible AC Transmission Systems (FACTS), HVDC (high-voltage direct current), Wide Area Monitoring, Protection and Control (WAMPAC), etc.
- Smart grid applications on distribution networks including distribution automation, fast demand response, including distributed resources (DRs) on the distribution feeders, distributed energy storage, controlled charging of plug-in electric vehicles (PEVs), demand-side management (DSM), etc.

Additional transmission planning is required to identify facilities and storage options to integrate these high levels of renewables.

Most of the models for these advanced wind and solar facilities have not been fully developed yet and need to be validated. The generator models for wind and solar generation technologies need to be upgraded and validated to include short-circuit models and dynamic variance models like clouding and short-term wind fluctuations.
The European experience with high levels of intermittent resources up to 80% penetration levels does not transfer fully due to the difference in U.S. grid design and load density. The integration of renewable energy at this scale will have significant impact, especially if the addition of energy storage devices (central and distributed) and FACTS devices utilized to counterbalance the influence of the intermittent generation sources. Utilities and ISOs in the United States should conduct Research, Development, and Demonstration (RD&D) projects and commence studies to fulfill its obligation to accurately and reliably forecast the impacts on future system integrated resource planning. Due to the long lead time for some of the proposed technology solutions, it is recommended that utilities engage these challenges sooner versus later. If technical challenges manifest, a timely solution cannot be implemented if studies, demonstration installations, and field tests still must be conducted. Additionally, utilities should study all conceivable options that may severely affect transmission system integrity and stability. Otherwise, utilities may experience unintended consequences due to unforeseen technical issues resulting from high penetrations of new renewable energy sources.

3.4 ENERGY STORAGE

Energy storage, in general, is a very old concept, even though it was not recognized as such. For instance, solar energy has been transformed and stored in the form of fossil fuels that are used today in many applications. Energy storage concepts have not been widely applied to power systems until recently, due mainly to technological and economic limitations given the large volumes of energy that typically are of interest in the power industry. Some exceptions are pumped hydro and uninterruptible power supply (UPS) systems. However, energy storage concepts have been commonly applied to other areas of electrical engineering, such as electronics and communications, where the amounts of energy to be stored are easier to manage.

3.4.1 REGULATORY AND MARKET FORCES

Grid energy storage or the ability to store energy within the power delivery grid can arguably be regarded as the “holy grail” of the power industry, and it is expected to play a key role in facilitating the integration of renewables, DRs and plug-in electric vehicles (PEVs) and fully enabling the capabilities, higher efficiency, and operational flexibilities of the smart grid. The main challenge with electric energy is that it must be used as soon as it is generated, or if not, it must be converted into other forms of energy. During the times when their assistance is not required, storage systems accumulate energy. Later, stored energy is dispatched into the power system for certain periods of time, thus decreasing the demand for generation and assisting the system when needed.

The ability to store energy in an economic, reliable, and safe way would greatly facilitate more efficient operation of the power systems. Unfortunately, high costs and technology limitations have constrained the large-scale application of storage systems. Historically, pumped hydro has been the most common application of energy storage technologies on power system level applications. Nevertheless, the last two decades have seen the emergence and practical applications of new technologies, such as battery systems and flywheels, prompted by the increasing interest and need to integrate intermittent renewable resources and PEVs, growing demand for high reliability, for instance, via implementation of microgrids, and the need for finding alternative technologies to provide ancillary services and system capacity deferral among others. There is growing interest worldwide in this area, and regulatory mechanisms and incentives are being proposed and debated.

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2 PEV—Plug-in electric vehicle, typically meant to include the entire family of grid-rechargeable vehicles, including plug-in hybrids (PHEVs), battery electric vehicles (BEVs or EVs), and extended range electric vehicles (EREVs).
One of the most successful regulations is currently in California where the California State Law (AB 2514) sets energy storage procurement targets in the State of California (Enacted 2010). The IOU utilities must procure and deploy 1.325 GW of energy storage by the year 2020. This legislation is designed for the following reasons:

- Reduce emissions of greenhouse gases
- Reduce demand for peak electrical generation
- Defer or substitute an investment in generation, transmission, or distribution assets
- Improve the reliable operation of the electrical transmission or distribution grid

A failed legislation, which provides a tax incentive, may be redrafted and implemented in the future. In this code, the U.S. Congress Storage Act of 2009 (S. 1091) called for an amendment to the Internal Revenue Code to:

- Allow a 20% energy tax credit for investment in energy storage property directly connected to the electrical grid (i.e., state systems of generators, transmission lines, and distribution facilities) and designed to receive, store, and convert energy to electricity and deliver such electricity for sale
- Make such property eligible for new, clean, renewable energy bond financing
- Allow a 30% energy tax credit for investment in energy storage property used at the site of energy storage
- Allow a 30% nonbusiness energy property tax credit for the installation of energy storage equipment in a principal residence

Other market examples include Australian State Governments directly funding deployment of storage, such as in South Australia (100 MW/129 MWh battery), Victoria (100 MW, undetermined energy capability); and the UK Government, which is funding £246 million of research, innovation and the scale-up of battery technology.

There are several main applications where energy storage systems can be used. Some of those include frequency regulation, spinning reserve, peak shaving/load shifting, and renewable integration [6].

3.4.1.1 Frequency Regulation

In practice, there always exists a mismatch between generation and load in a power system. This mismatch results in frequency variations. System operators are always trying to match the generation to the load so that the frequency can be as close as possible to 60 Hz (or 50 Hz in Europe and Australia and other International Electrotechnical Commission (IEC) standards-based countries). Variability of the frequency is further increased by the addition of intermittent renewables, such as solar and wind. Any power system is required to maintain the frequency within the desired limits. Any large variations from 60 Hz will cause unwanted system instability and can bring the whole system down. As noted earlier, system operators are trying to balance the generation and load by varying the output of certain generating units based on the system frequency. This type of regulation is called frequency regulation. In addition to having the whole system being able to supply power for the desired load, utility operators always have an extra amount of generation that is known as spinning reserve. This spinning reserve must be enough to provide power for frequency regulation purposes as well as support the tripping of the largest generating unit in the system to prevent the power interruptions. The amount of regulation capacity is most based on historical records and might vary on several factors, such as time of the day and time of the year.

One basic difference between the regulated and deregulated markets is that deregulated markets may have a market for ancillary services, such as frequency regulation. In this market,
reserve capacities of every generating unit can be bid and market price is paid for capacity reserved for the regulation as well as actual provided energy. The system works by using a control system for each balancing authority that sets the outputs of each generation asset. The system computes the difference between the power output and load demand (adjusted with frequency error bias) called area control error or ACE. From this signal, another signal called automatic generation control or AGC is computed and sent to regulation service providers. These providers, in turn, adjust their power output based on the AGC signal that was received. A frequency increase requires providers to supply additional power to the grid, which is equivalent to an energy storage system discharging energy to the system. On the opposite side, a frequency decrease requires providers to reduce power to the grid, which is equivalent to charging an energy storage system.

In the past, thermal generators or hydro facilities have been used to provide frequency regulation due to their fast response, which is needed for effective regulation. However, this was not the most optimal way for economic dispatch because of the emissions, fuel costs, losses, and increased wear and tear on the generating sources. In addition, these are sometimes base-load generating plants, so output had to be reduced to provide frequency regulation capacity, which, in turn, caused higher-cost generating units to be online to support the load. Energy storage that provides frequency regulation allows for better optimization of generation assets. In addition, every MW of renewable resources added to the system will require between 3% and 10% increase in regulation service.

3.4.1.2 Spinning Reserve
As mentioned earlier, the total generation in a region that belongs to one utility system is equal to the load demand plus some spinning reserve. The amount of spinning reserve is equal or larger to the highest power-producing unit connected to the system plus some margin. The reason for this is the need for immediate additional power if the largest unit goes off-line suddenly. Knowing that it takes a certain amount of time to start any generating unit, having energy storage systems provides additional benefit because those systems can be immediately deployed. During the high-load periods, majority of thermal and hydro units are dispatched and run at their maximum efficiency and cannot be utilized as spinning reserve. So, to have spinning reserve, additional units are needed. Note that during light- or medium-load conditions, these generating units have output less than maximum, with the difference being designated as spinning reserve. Committing generating resources for spinning reserves is mandatory, but it results in increased operating costs and decreased efficiency. Energy storage systems help in reduction of spinning reserves provided by thermal and hydro generating units and allow dispatchers to set operating points at maximum levels during the economic dispatch. Like frequency regulation market, in deregulated markets, there exists a spinning reserve service market, where generation owners bid to provide this service. The only downside to energy storage systems is that they provide output only for a limited amount of time. After the energy storage system has started providing energy to the utility system, additional generating units must be deployed before the output of energy storage systems runs out to avoid service interruptions. At a time where energy storage systems come at a premium cost, a possible strategy is to size the energy storage system to be able to support the service while a peaking generator is started and ramps up to the desired output. As energy storage systems decrease their costs, they may be able to serve more of the requirements in a cost-effective way.

3.4.1.3 Peak Shaving and Load Shifting
Load demand is always changing, and utilities employ different techniques to predict daily load curves. Major inputs into load estimation are temperature, load demand during the last seven to ten days, and historical data. Based on the estimated load curves, economic dispatch is created to
identify generating units that will be supplying the needed power along with spinning reserves and uncertainty in load estimation. Every generating unit has operating costs, and economic dispatch is based on these costs. Units with lowest operating costs are used for base loading, and run most of the time. For example, nuclear, hydro, and modern coal plants are almost exclusively used for base load generation. Note here these units also have the highest capital cost of construction. To cover the peak load demand, utility must bring on-line its higher operating cost generating units. For example, plants that have combustion turbines (CTs) might only be utilized a few hours during the whole year to cover the peak load. To level demand and move energy usage toward the off-peak hours, energy must be stored first. This can be done during the time with low demand because the cost of generation is low. This energy can be supplied from energy storage systems to the grid during the peak times.

3.4.1.4 Renewable Integration
Energy storage, power electronics, and communications have a key role to play to mitigate the intermittency and ramping requirements of large-scale renewable energy penetration of wind and solar energy. Since their inception, wind and solar technologies have made major breakthroughs and become more reliable and cost effective. Many utilities are constantly incorporating additional renewable resources into their generation portfolios. However, the biggest issue associated with wind and solar power is their unpredictability and variability of the output, although developments in wind forecasting techniques have come a long way to give a much higher predictability to the use of wind in the system. Solar forecasting techniques are also being developed to bring increased forward-looking visibility. These developments will reduce the need for regulation and support a higher-carrying capacity at a lower cost. In addition, these technologies also require regulation. Solar and wind energy productions are not dispatchable and result typically in high levels of power and associated voltage fluctuations. However, coupled with sophisticated forecasting techniques, they can be used for bidding in wholesale markets. Common problems in remote wind production areas include low capacity factors for all the wind farms, impacts of line contingencies on wind farm operations, curtailment of wind farm outputs during high production times, and high ramp rate requirements [4]. In most urban regions, PV flat-plate collectors are predominately used for solar generation and can produce power production fluctuations with a sudden (seconds time scale) loss of complete power output. With partial PV array clouding, large power fluctuations can also result at the output of the PV solar farm with large power quality impacts on distribution networks. These power variations on large-scale penetration levels can produce several power quality and power balancing problems. Cloud cover and morning fog require fast ramping and fast power balancing on the interconnected feeder. Furthermore, several other solar production facilities are normally planned in close proximity on the same electrical distribution feeder that can result in high levels of voltage fluctuations and even flicker. Reactive power and voltage profile management on these feeders are common problems in areas where high penetration levels are experienced. In the case of low voltage (LV) feeders that support a large number (50–150) of customers (e.g., Australia), situations of low-load high solar production can contribute to voltage rise in distribution networks to levels that can either cause potential problems to PV owners (their inverters trip under high-voltage conditions) or to appliances of all users in the feeder, driving the need for anticipated network upgrades and the associated expense.

3.4.2 Technologies
Energy storage methods can be divided into several groups: chemical, electrical, electrochemical, mechanical, thermal, and biological. Table 3.1 summarizes some of the most common types of energy storage systems connected to the utility power grid.
3.4.2.1 Batteries

Battery energy storage is mostly used for load leveling (Figure 3.1), peak shaving, PV smoothing, and frequency regulation. Today, there are two main types of batteries based on their chemistry and structure. One type is called a power battery, and these batteries can deliver fast charge/discharge. These types of batteries are mainly used for frequency regulation and PV smoothing. Another type
of battery has slow charge/discharge times, and those types of batteries are mostly used for load leveling and peak shaving.

Energy storage systems can be used for smoothing the power out of renewable sources. This can be accomplished by limiting the rate of change of the output of a renewable resource. Energy storage systems can either add or remove power from the system as needed to smooth the power output of a renewable resource. One of the most promising solutions to mitigate these integration issues is by implementing a hybrid fast-acting energy storage and STATCOM (static synchronous compensator) in a smart grid solution. Several fast-reacting energy storage solutions are currently available on the market. For mitigating the mentioned wind and solar integration problems, the energy storage device needs to be fast acting and a storage capability of typically 15 min to 4 h and a STATCOM that is larger than the battery power requirements to have adequate dynamic reactive power capabilities. Figure 3.2 shows an example of a STATCOM

FIGURE 3.1  Conceptual description of grid energy storage. (a) Network power flows and (b) energy storage and release cycles. (From Wikipedia, Grid Energy Storage, http://en.wikipedia.org/wiki/Grid_energy_storage.)
and battery energy storage application for mitigating a wind farm-related integration issue [9]. The main components and technical characteristics of this smart energy storage solution are as follows:

- 8 MW/4 h battery
- 20 MVAr inverters for the battery energy storage and STATCOM
- Integrated control and HMI (human-machine interface) of STATCOM and battery energy storage system
- Substation communications interface for integrating the battery energy storage solution into a distribution automation and ISO market participation environment

High-power batteries, efficient inverters, and sophisticated switching make energy storage a practical new technology application for distribution systems. There are a small but growing number of installations of 0.25–4 MW energy storage systems on utility systems using a wide variety of battery technologies. Figure 3.3 is an example of bulk energy storage (“utility-scale”) installed in a utility substation that can be used for a variety of applications. In a peak shaving application, the intelligence in the control system charges the batteries during off-peak times and then supplies energy during peak times. This creates several opportunities for economic justification, such as the ability to make full use of intermittent renewable sources regardless of the time of day or present loading, the ability to shave peak load, and the deferral of substation and feeder capacity upgrades. This utility-scale energy storage can also be used for microgrid applications.

Energy storage that is connected to the electric distribution system outside the substation is likely to be of smaller MW sizes but can still have a great impact on reliability and automatic restoration systems. Figure 3.4 shows an example of a smaller footprint 250kW energy storage inverter and controller that would be installed out of the substation closer to the customer (“community-scale” storage), perhaps also installed on a large commercial or industrial customer site. The batteries would typically be separate to the inverter in an adjacent cabinet.
3.4.2.2 Superconducting Magnetic Energy Storage (SMES)

SMES stores energy in the magnetic field that is created due to the flow of DC in a superconducting coil. The coil has been cooled cryogenically to below its superconducting critical temperature. SMES consists of three parts: bidirectional AC/DC inverter system, superconducting coil, and cryogenically cooled refrigerator. DC charges the superconducting coil, and when the coil is charged, it stores magnetic energy until it is released. This energy is released by discharging the coil. Bidirectional inverter is used to convert AC to DC power and vice versa during the coil
charging/discharging cycles. The cost of SMES is high today because of its superconducting wires and refrigeration energy use, and its main use is for reducing the loading during the peak times.

The main technical challenges associated with SMES are large size, mechanical support due to high forces, superconducting cable manufacturing, infrastructure required for installation, low levels of critical current when superconducting properties of materials break down, levels of critical magnetic field, and health effects due to exposure to large magnetic fields.

### 3.4.2.3 Flywheels

Flywheel Energy Storage (FES) operates on the principle of conservation of rotational momentum—a flywheel is accelerated to a very high speed to store kinetic energy. When energy is demanded from the system, the flywheel rotational speed is reduced. To reduce friction during the rotation, a vacuum chamber is used to contain the rotor. The rotor is connected to an electric motor or generator. FES is not affected by the change of temperature, and stored energy is easily calculated, but the main danger is the fatigue failure of the flywheel and the containment of damage from any failure.

### 3.4.2.4 Compressed Air

Energy generated at one point in time (off-peak) can be stored and later used during different periods of time (peak). Compressed Air Energy Storage (CAES) represents one viable option. There are three types of air storage: adiabatic, diabatic, and isothermic. Adiabatic storage retains the heat that is produced by compression and later returns the heat to the air when the air is expanded to generate power. Diabatic storage dissipates some portion of heat as waste. For air to be used after it is removed from storage, it must be heated again prior to expansion in the turbine to power the generating unit. Isothermal storage operates under the same temperature conditions by utilizing the heat exchanger. These exchangers account for some losses.

Most CAES systems currently in operation do not utilize the compressed air to directly generate electricity [10]. Rather, the compressed air is fed into simple-cycle CTs, reducing the compression work in the standard recuperated Brayton cycle. In this mode, the CAES system serves to precompress combustion air during off-peak periods, improving the output of the CT during on-peak periods.

### 3.4.2.5 Ultracapacitors

Ultracapacitors or supercapacitors are storage devices for DC energy. To be able to be connected to the power grid, a bidirectional AC/DC inverter is needed. Because of their fast charge/discharge rates, ultracapacitors are used only during short power interruptions and voltage sags.

Unlike batteries where energy is stored chemically, ultracapacitors store this energy electrostatically. Ultracapacitors consist of two electrodes called collector plates, which are suspended in an electrolyte. The dielectric separator is placed between the collector plates to prevent the charges from moving from one electrode to another. Applied potential difference between the two collector plates causes negative ions in the electrolyte to be attracted to the positive collector plate and positive ions in the electrolyte to be collected on the negative collector plate.

Ultracapacitors have several advantages and disadvantages compared to batteries. Some of the disadvantages include lower amount of energy stored per unit of weight, more complex control and switching equipment, high self-discharge, additional voltage balancing, safety issues, while some of the advantages include long life, low cost per cycle, good reversibility, high rate of charge/discharge, high efficiency, and high output power.

### 3.4.2.6 Pumped Hydro

Pumped hydro storage method stores energy in the form of water, which is pumped from a reservoir on a lower elevation to a reservoir on a higher elevation. This is done during the off-peak hours when the cost of production of electricity necessary to run the pumps is lower. During the high-demand period, this water is released through the turbines. Pumped hydro is the highest-capacity storage
3.4.2.7 Thermal
Thermal energy storage consists of a series of technologies that store thermal energy in reservoirs (e.g., using molten salt or ice) when electricity production is cheap (e.g., during off-peak, when most of the electricity is produced by using efficient and relatively inexpensive “base” units) and releases it for heating or cooling purposes when electricity production is expensive (e.g., during peak, when electricity is produced by using costly “peaking” units), which equates to electricity production savings and/or T&D capacity deferral due to load shaving.

Recent developments in thermal storage have investigated conversion of stored heat directly into electricity, using Brayton or Rankine cycles [11]. Work on these systems has been catalyzed by thermal storage systems utilized for concentrating solar power, where excess heat captured during the day is stored for power generation in the evening. Round-trip efficiency of electrical-thermal storage remains problematic, with typical verified efficiencies below 30%. As a result, much attention is currently focused on increasing the temperature of thermal storage to greater than 500°C, utilizing phase-change materials to reduce system size and augmenting thermal storage material to improve thermal conductivity within the storage tanks.

3.4.3 Energy Storage in the Smart Grid
Energy storage applications can be centralized or distributed. The selection of the type of solution and technology to be used in an application is a function of the type of problem to be addressed and a series of technical and economic considerations such as ratings, size and weight, capital costs, life efficiency, and per-cycle cost. Figure 3.5 shows a summary of the installed

![Energy Storage Pie Chart]

**FIGURE 3.5** More than 1500 installed grid-connected energy storage projects worldwide as July of 2016. (From DOE Global Energy Storage Database, http://www.energystorageexchange.org/projects/data_visualization.)
grid-connected energy storage technologies worldwide. Table 3.2 summarizes the key grid applications of energy storage.

Centralized energy storage applications consist of large MW-size facilities usually connected to transmission system level voltages; these applications are typically used for providing ancillary services during short periods of time (e.g., seconds or minutes) and for mitigating the impacts of intermittent renewable generation. Distributed storage consists of smaller MW-size facilities connected to distribution system level voltages, either at distribution substations, feeders, or customer facilities;

<table>
<thead>
<tr>
<th>TABLE 3.2</th>
<th>Energy Storage Applications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric (grid-supplied) energy time shift</td>
<td>Charges the storage plant with inexpensive electric energy purchased during low price periods and discharges the electricity back to the grid during periods of high price</td>
</tr>
<tr>
<td>Electric supply capacity</td>
<td>Reduces or diminishes the need to install new generation capacity</td>
</tr>
<tr>
<td>Load following</td>
<td>Alters power output in response to variations between electricity supply and demand in a given area</td>
</tr>
<tr>
<td>Area regulation</td>
<td>Reconciles momentary differences between supply and demand within a given control area</td>
</tr>
<tr>
<td>Electric supply reserve capacity</td>
<td>Maintains operation when a portion of normal supply becomes unavailable</td>
</tr>
<tr>
<td>Voltage support</td>
<td>Counteracts reactive effects to grid voltage so that it can be upheld or reinstated</td>
</tr>
<tr>
<td>Transmission support</td>
<td>Enhances transmission and distribution system performance by offsetting electrical irregularities and interruptions</td>
</tr>
<tr>
<td>Transmission congestion relief</td>
<td>Avoids congestion-related costs by discharging during peak demand to reduce transmission capacity requirements</td>
</tr>
<tr>
<td>Transmission and distribution upgrade deferral and substitution</td>
<td>Postpones or avoids the need to upgrade transmission and/or distribution infrastructure</td>
</tr>
<tr>
<td>Substation on-site power</td>
<td>Provides power to switching components and communication and control equipment</td>
</tr>
<tr>
<td>Time-of-use energy cost management</td>
<td>Reduces overall electricity costs for end users by allowing customers to charge storage devices during low price periods</td>
</tr>
<tr>
<td>Demand charge management</td>
<td>Reduces charges for energy drawn during specific peak demand times by discharging stored energy at these times</td>
</tr>
<tr>
<td>Reliability</td>
<td>Provides energy during extended complete power outages</td>
</tr>
<tr>
<td>Power quality</td>
<td>Protects on-site loads against poor quality events by using energy storage to protect against frequency variations, lower power factors, harmonics, and other interruptions</td>
</tr>
<tr>
<td>Renewables energy time-shift</td>
<td>Stores renewable energy (which is frequently produced during periods of low demand) to be released during periods of peak demand</td>
</tr>
<tr>
<td>Renewables capacity firming</td>
<td>Addresses issues with ramping from renewable sources by using stored energy in conjunction with renewable sources to provide a constant energy supply</td>
</tr>
<tr>
<td>Wind/solar generation grid integration</td>
<td>Assists in wind- and solar-generation integration by reducing output volatility and variability, improving power quality, reducing congestion problems, providing backup for unexpected generation shortfalls, and reducing minimum load violations</td>
</tr>
</tbody>
</table>

this includes applications such as community energy storage (CES) and vehicle-to-grid (V2G). CES is a concept that is increasingly being implemented with applications ranging from 25 kWh to 75 kWh and devices similar to pad-mounted distribution transformers. Distributed energy storage, in general, is typically used for intermittent renewable generation integration, distribution reliability improvement, capacity and T&D deferral; therefore, they are required to have longer storage times (e.g., minutes or hours), as shown in Figure 3.6. This application is also increasingly being considered for integration of PEVs. The US DOE and Energy Storage Association (ESA) provide very comprehensive descriptions of the recommended applications, as well as advantages and disadvantages of each technology, which are summarized in Table 3.1 and Figure 3.6, and discussed in the next sections.

The coordinated implementation of smart grid technologies, such as distributed energy storage, communications, control, power electronics, and power system technologies, allows the seamless integration of intermittent DG and adds further capabilities to it including controllability (i.e., dispatchability) and predictability. These capabilities can be used for capacity planning applications (e.g., capacity deferral), increased operational flexibility during outages (intentional islanding), and reliability improvement. Furthermore, distributed storage in the smart grid context may be used to mitigate impacts caused by both, DG (especially PV) and PEVs. Table 3.3 summarizes the suitability of energy storage technologies for grid applications.

![Figure 3.6: Energy storage technology ratings and discharge times for electric utility applications. (From Sandia Report Electricity Storage Handbook, SAND2015-1002, February 2015.)](image)
### TABLE 3.3

**Suitability of Energy Storage Technologies for Grid Applications**

<table>
<thead>
<tr>
<th>Application Description</th>
<th>CAES</th>
<th>Pumped Hydro</th>
<th>Flywheels</th>
<th>Lead-Acid</th>
<th>NaS</th>
<th>Li-ion</th>
<th>Flow Batteries</th>
</tr>
</thead>
<tbody>
<tr>
<td>Off-to-on peak intermittent shifting and firmin</td>
<td><img src="image" alt="Definite suitability for application" /></td>
<td><img src="image" alt="Possible use for application" /></td>
<td><img src="image" alt="Possible use for application" /></td>
<td><img src="image" alt="Possible use for application" /></td>
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<td><img src="image" alt="Possible use for application" /></td>
<td><img src="image" alt="Definite suitability for application" /></td>
</tr>
<tr>
<td>On-peak intermittent energy smoothing and shaping</td>
<td><img src="image" alt="Definite suitability for application" /></td>
<td><img src="image" alt="Definite suitability for application" /></td>
<td><img src="image" alt="Possible use for application" /></td>
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<td><img src="image" alt="Definite suitability for application" /></td>
<td><img src="image" alt="Possible use for application" /></td>
</tr>
<tr>
<td>Ancillary service provision</td>
<td><img src="image" alt="Definite suitability for application" /></td>
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3.5 ELECTRIC VEHICLES

3.5.1 REGULATORY AND MARKET FORCES

With the implementation of smart grid technologies and the associated improvements in the reliability, sustainability, security, and economics of the electric grid comes the opportunity to include vehicles as an active participant in the smart grid. Although electrification of segments of the transportation energy sector does not require any technological or systemic advancements of the electric grid over what is presently available, the large scale of the transportation energy sector will provide long-term challenges to the legacy systems of the electric grid along with considerable opportunities for improved power, energy, and economic management in a smart grid system.

Electric transit (including electric trains and catenary trolleybuses) has a long history of integration with the electric grid. Electric transit has traditionally always operated at large, centralized scales, “tethered” to the grid. These technologies require a more-or-less continuous provision of electricity during operation of the vehicle. The introduction of high-density energy storage has introduced a watershed change in electric transportation in the form of distributed, small vehicles operating in an untethered mode. The ongoing and large-scale introduction of PEVs to the world automotive fleet is one of the most important changes to the transportation energy sector in history, and the capabilities of the smart grid will play a large role in determining whether the electricity sector can realize benefits from this integration.

Relative to a conventional internal combustion vehicle or conventional HEV baseline, there are numerous potential benefits that come with the electrification of transportation energy through PEVs [15]:

- Reduced petroleum (fossil fuel) consumption
- Lower life-cycle greenhouse gas and pollutant emissions (depending on the mix of electricity generation type)
- Typically lower fueling costs
- Lower life-cycle cost of ownership (depending on vehicle comparison)

Because of these potential benefits, there is a steady and growing interest in the development of PEVs. Numerous traditional and entrepreneurial automakers have research, development, and limited production plug-in vehicle programs. Nearly every OEM and several entrepreneurial vehicle manufacturers have launched large-scale production PEV programs. The rate of introduction of PEVs into the world vehicle fleet will continue to accelerate under pressures from regulators, such as Environmental Protection Agency (USA), California Air Resources Board, and others. The increasing commercial and private investment in PEVs will drive a corresponding investment in electrical infrastructure servicing PEVs. This investment in infrastructure will include public and in-home electric charger installations, which will incorporate passive or active forms of communication to facilitate the integration of large fleets of PEVs onto the electric grid.

The following sections will examine the potential impact of PEVs on the existing grid, describe methods of using smart grid technologies to alleviate foreseen problems, and investigate potential opportunities to enhance the performance of the electric grid using PEVs.

3.5.2 TECHNOLOGIES

3.5.2.1 Hybrid (HEV)

An HEV is a type of EV that uses a combination of a conventional Internal Combustion Engine (ICE) and an electric motor for propulsion. HEVs use different technologies to improve efficiency and reduce emissions; such technologies include using regenerative breaking, using the ICE to generate
electricity to recharge batteries or power the electric motor, and using the electric motor during most of the time and reserving the ICE for propulsion only when needed. Commercial examples of this type of vehicle include the Toyota Prius and the Honda Insight. HEVs are not PEVs since they can operate autonomously without the need of recharging batteries using the power grid. Therefore, no impact on the power grid is expected from proliferation of this type of EV.

### 3.5.2.2 Plug-in Hybrid (PHEV)

A PHEV is a type of EV that has an ICE and an electric motor (like an HEV) and a high-capacity battery pack that can be recharged by plugging-in the car to the electric power grid (like a BEV). There are two basic PHEV configurations [16]:

- **Series PHEVs** or Extended Range Electric Vehicles (EREVs) are PEVs where only the electric motor and drivetrain provide tractive power to the wheels and the ICE is only used to generate electricity. Series PHEVs can run solely on electricity until the battery is discharged. The ICE will then generate the electricity needed to power the electric drivetrain. For shorter trips, these vehicles might use no gasoline at all.
- **Parallel or blended PHEVs** are PEVs where both the engine and electric motor are mechanically connected to the wheels, and both propel the vehicle under most driving conditions. Electric-only operation usually occurs only at low speeds.

The main advantage of PHEVs with respect to BEV is that PHEVs have longer driving range and shorter recharge time. Relative to conventional internal combustion engine vehicles, PHEVs are characterized by lower operation cost and lower environmental impact.

### 3.5.2.3 Battery (BEV)

A battery electric vehicle (BEV) is a type of EV that uses rechargeable battery packs to store electrical energy and an electric motor (DC or AC depending on the technology) for propulsion. Intrinsically it is a PEV since the battery packs are charged via the electric vehicle supply equipment (EVSE), that is, by “plugging-in” the BEV. The North American standard for electrical connectors for EVs is the SAE J1772, which is being maintained by the Society of Automotive Engineers (SAE) [17]. The standard defines two charging levels AC Level 1 (120 V, 16 A, single-phase) and AC Level 2 (208–240 V, up to 80 A, single-phase). Furthermore, additional work is being conducted on standardizing Level 3 (300–600 V, up to 400 A, DC). The technical requirements of BEV batteries are different from those of other energy storage applications include demanding requirements on power/weight ratio, energy/weight ratio, cost, and energy density. At present, a variety of lithium-ion chemistries has demonstrated the ability to meet these requirements in the automotive application. No single lithium-ion chemistry has yet emerged as dominant in the BEV application. Since BEVs do not have combustion engines, their operation fully depends on charging from the electric grid. Therefore, uncontrolled charging cycles of BEVs under scenarios of high market penetration may cause increased loads on power distribution systems. For example, if BEVs are charged upon their return to “home,” their loads may be coincident with the afternoon/evening residential demand peak, leading to higher costs to generate, transmit, and distribute electricity to vehicles [18].

In the US, BEVs are, as of 2016, the highest selling EVs in the market. US PHEV and BEV sales for the 2010–2016 period exceeded 550,000 units, as shown in Figure 3.7.

### 3.5.3 Electric Vehicles in the Smart Grid

The adoption of electric vehicles reduces gasoline consumption and tailpipe emissions and improves the urban area air quality. However, electric vehicles can have disruptive impacts on the power grid if they are not integrated carefully. Most vehicles return home in late afternoon and
early evening. If they all begin charging the moment they arrive home, the power grid, which may already be at peak load, can have difficulties providing for the additional demand. Distribution system problems, such as transformer overloading and feeder congestion, may become more prevalent. At a larger scale, the bulk system may lack the necessary supply capacity to meet the added demand. Therefore, generation, transmission, and distribution systems are expected to require costly upgrades to support the demand of many more electric vehicles. However, the difference between the total time required to fully charge an electric vehicle and the total time that the vehicle is plugged in allows for charging flexibility that can potentially be used to charge vehicles in a more grid-friendly way.

The environmental benefits of fuel switching from gasoline to electricity is not going to be fully achieved if primarily fossil resources are used to supply the energy requirement of electric vehicles. The main obstacle to non-fossil resources (excluding nuclear that has its own challenges) is the intermittency of renewable generation, which limits the amount that can be integrated and compels system operators to schedule/dispatch expensive reserve units. Implementation of charge controlling strategies eases the operation of bulk power systems with a high penetration level of intermittent renewables, which is beneficial from both economic and environmental perspectives.

The role of electric vehicle demand response is to facilitate a cost-effective and emission-minimizing alignment between charging demand and available energy supply resources. Our interest in demand response for electric vehicles is motivated by the fact that the EV load is inherently different from other deferrable loads, and including this load in the demand response will increase the diversity of the flexible load fleet, and as a result potentially its performance capabilities: (1) EV loads can be delayed for relatively more time than thermostatically controlled loads; (2) EVs can potentially feed electricity into the grid; (3) EV chargers are physically located where other flexible loads may not exist; (4) charging stations are equipped with controls that can provide system operators with

voltage response resources even when no EV is plugged to it; and (5) the power factor of the EV charger load differs from other flexible electric loads, which is valuable from the operation point of view.

### 3.5.3.1 Grid Support

Due to the higher cost of PEVs compared to conventional vehicles, research has been conducted to determine if PEVs can provide additional services to help offset the added expense of a PEV. Studies have shown that vehicles sit unused, on average, for >90% of the day [20]. Using this fact, researchers have conducted studies on the ability of PEVs to provide grid support services to provide a source of revenue for the vehicle owner. If this revenue helped offset the initial cost of the plug-in vehicle, it could increase the incentive for consumers to purchase PEVs. The primary means for monetizing the capabilities of PEVs is proposed participation in a deregulated ancillary services market. Studies to date have determined that frequency regulation is the component of the ancillary services market most compatible with plug-in vehicle capabilities and will provide the largest financial incentive to vehicle owners [21–23].

There are two primary types of power interactions possible between the vehicle and the electric grid. Grid-to-vehicle charging (G2V) consists of the electric grid providing energy to the plug-in vehicle through its charging connector. G2V is the traditional method for charging the batteries of BEVs and PHEVs. A vehicle-to-grid (V2G) capable vehicle has the additional ability to provide energy back to the electric grid. V2G provides the potential for the grid system operator to call on the vehicle as a distributed energy and power resource.

For PEVs to achieve widespread near-term penetration in the ancillary service market, the two primary stakeholders in the plug-in vehicle ancillary service transaction must be satisfied: grid system operators and vehicle owners. The grid system operators demand industry standard availability and reliability for regulation services. The vehicle owners demand a robust return on their investment in the additional hardware required to perform the service and minimal impact on the performance and lifetime of the vehicle’s battery.

Since PEVs are not stationary but instead have stochastic driving patterns, these resources possess unique availability and reliability profiles in comparison to conventional ancillary services generation system. In addition to this, the power rating of an individual plug-in vehicle is significantly less than the power capacity of conventional generation systems that utilities normally contract for ancillary services. These key aspects of PEVs create unique challenges for their integration and acceptance into conventional power regulation markets to provide ancillary services.

The connection between the grid system operators and the PEVs to provide grid support services can be classified as one of two types that have been proposed to date: a direct, deterministic architecture and an aggregative architecture. The direct, deterministic architecture, shown conceptually in Figure 3.8, assumes that there exists a direct line of communication between the grid system operator and the plug-in vehicle so that each vehicle can be treated as a deterministic resource to be commanded by the grid system operator. Under the direct, deterministic architecture, the vehicle can bid and perform services while it is at the charging station. When the vehicle leaves the charging station, the contracted payment for the previous full hours is made, and the contract is ended. The direct, deterministic architecture is conceptually simple, but it has recognized problems in terms of near-term feasibility and long-term scalability.

First, there exists no near-term information infrastructure to enable the required line of communication. The direct, deterministic architecture cannot use the conventional control signals that are currently used for ancillary service contracting and control because the small, geographically distributed nature of PEVs is incompatible with the existing contracting frameworks. For example, the peak power capabilities of individual vehicles (1.8 kW [25], 17 kW [26]) are well below the 500 kW–1 MW threshold that is required for many ancillary service hourly contracts [27].
In the longer-term, the grid system operator might be required to centrally monitor and control all the PEVs subscribed in the power control region—a potentially overwhelming communications and control task [28]. As these millions of vehicles engage and disengage from the grid, the grid system operator would need to constantly update the contract status, connection status, available power, vehicle state of charge, and driver requirements to quantify the power that the system operator can deterministically command. This information would need to be fed into the operator’s market system to determine contract sizes and clearing prices.

The aggregative architecture is shown conceptually in Figure 3.9. In the aggregative architecture, an intermediary is inserted between the vehicles performing ancillary services and the grid system operator. This aggregator receives ancillary service requests from the grid system operator and issues power commands to contracted vehicles that are both available and willing to perform the required services. Under the aggregative architecture, the aggregator can bid to perform ancillary services at any time, while the individual vehicles can engage and disengage from the aggregator as they arrive at and leave from charging stations. This allows the aggregator to bid into the ancillary service market using existing contract mechanisms and compensate the vehicles under its control for the time that they are available to perform ancillary services. As such, this aggregative architecture attempts to address the two primary problems with the direct, deterministic architecture.

First, the larger scale of the aggregated power resources commanded by the aggregator and the improved reliability of aggregated resources connected in parallel allow the grid system operator to treat the aggregator like a conventional ancillary service provider. This allows the aggregator to utilize the same communications infrastructure for contracting and command signals that conventional ancillary service providers use, thus eliminating the concern of additional communications workload placed on the grid system operator.

In the longer term, the aggregation of PEVs will allow them to be integrated more readily into the existing ancillary service command and contracting framework, since the grid system operator needs only directly communicate with the aggregators. The communications network between...
the aggregator and the vehicles is of a more manageable scale than communications network required under the direct, deterministic architecture. The aggregative architecture is, therefore, more extensible than the direct, deterministic architecture as it allows for the number of vehicles under contracts to expand by increasing the number of aggregators, increasing the size of aggregators, or both. Since many distribution utilities are installing “advanced metering” systems, allowing two-way communication with individual consumers, these utilities could potentially enter the ancillary service market by providing such aggregation services using their metering communications networks. From the perspective of the grid system operator, the aggregative architecture represents a more feasible and extensible architecture for implementing PEVs as ancillary service providers. For the system operator, the aggregative architecture is an improvement relative to the direct, deterministic architecture because it allows PEVs to make use of the current market-based, command and control architectures for ancillary services. Aggregators can control their reliability and contractible power to meet industry standards by controlling the size of their aggregated plug-in vehicle fleet, thereby providing the grid system operator with a buffer against the stochastic availability of individual vehicles. This allows the aggregator to maintain reliability equivalent to conventional ancillary service providers including conventional power plants. Because the payments from the grid system operator for ancillary services are equal for both architectures, the direct, deterministic architecture offers no apparent advantages from the perspective of the grid system operator.

From the perspective of the vehicle owner, the direct, deterministic architecture is preferred relative to the aggregative architecture. The initial allowable investment for the aggregative architecture is ~40% of the initial allowable investment for the direct, deterministic architecture [24]. The substantially higher initial investments allowed by the direct, deterministic architecture suggest that the average vehicle owner will prefer the direct, deterministic architecture.

These divergent preferences of the vehicle owners and the system operator highlight a fundamental problem that must be overcome before PEVs can be successfully implemented into the ancillary service market. The differing requirements of the stakeholders make only the aggregative architecture acceptable to both parties. The direct, deterministic architecture is unacceptably complex,
unreliable, and unscalable to utilities and grid system operators. The aggregative architecture more than halves the revenue that can be accrued by the vehicle owners but still allows for a positive revenue stream. Only the aggregative architecture is mutually acceptable to all stakeholders and can provide a more feasible pathway for the realization of a near-term utilization of PEVs for ancillary service provision.

3.5.3.2 Energy Buffering

There exists a daily load cycle for the U.S. electric grid. In general, the grid is relatively unloaded during the night and reaches peak loading during the afternoon hours in most U.S. climates. Balancing authorities dispatch power plants to match the power generation to the time-varying load. Types of generation resource are dispatched differently to meet different portions of the load. Nuclear and large thermal plants are typically dedicated to relatively invariant “base-load” power. Thermal generation with fast response rates (e.g., combustion turbines), hydropower, and energy storage can be dispatched to meet predicted and actual load fluctuations. By combining generation types, the control authority meets the time-varying load with a time-varying power generation, while meeting constraints imposed by environmental requirements, emission caps, transmission limitations, power markets, generator maintenance, unplanned outages, and more.

Even at relatively low market penetrations, plug-in vehicles will represent a large new load for the electric grid, requiring the generation of more electrical energy. In one set of scenarios analyzed by NREL researchers, a 50% plug-in market penetration corresponded to a 4.6% increase in grid load during peak hours of the day [29]. When vehicle charging and discharging can be controlled, other studies have found that as many as 84% of all U.S. cars, trucks, and SUVs (198 million vehicles) could be serviced using the present generation and transmission capacity of the U.S. electrical grid [30]. Controlling the electrical demand of PEVs will determine the infrastructure, environmental and economic impacts of these vehicles. Smart grid technologies can provide the control, incentives, and information to enable the successful transition to PEVs, but these technologies must reconcile the requirements of the electricity infrastructure with the expectations and economic requirements of the vehicle owner.

The simplest and most effective means for controlling the energy consumption of PEVs is direct utility control of charging times. Under this scenario, the utility would only allow consumers to charge during off-peak hours. By filling the nightly valley in electrical load, PEVs would reduce the hourly variability of the load profile. This has the effect of improving the capacity factor of base-load power plants, reducing total emissions and costs, and eliminating the load growth due to plug-in vehicle market penetration. From a utility perspective, having direct control of the vehicle charging is ideal. From a consumer perspective, the willingness of vehicle owners to tolerate utility control of charging times depends on the type of plug-in vehicle that is being considered. For BEVs, the charger is the only source of energy for the vehicle, and being limited to charging during off-peak periods would significantly limit the usability of the vehicle and perhaps reduce its consumer acceptability. For PHEVs, the vehicle can operate with normal performance and reduced fuel economy when charging is not available. The degree to which consumers would tolerate increased fueling costs due to utility control of charging is under debate.

A more acceptable means for using smart grid technologies to control the energy consumption of plug-in vehicles is by providing incentives for off-peak charging through a time-of-use (TOU) rate. A TOU rate is an electricity rate structure where the cost of electricity varies with time. Smart grid technologies, such as advanced metering and consumer information feedback, are necessary conditions for implementation of TOU tariffs. TOU rates are generally designed to represent the fact that electricity is more expensive during the day (when the grid is highly loaded) and less expensive during the night (when the grid is lightly loaded) to incentivize the conservation of electricity during the day. Special TOU rate structures have been designed for EV use to encourage EV owners to charge their vehicles at night, thereby conserving electricity during hours of peak
demand. These legacy EV TOU rate structures have also been made available to PHEV owners. In theory, TOU rates should be able to be designed to provide an economic incentive for plug-in vehicle owners to charge their vehicles at night. In practice, the TOU rate can provide robust economic incentives for EV owners to charge their vehicle during off-peak periods because electricity is the only fuel cost for EVs. When TOU rates are applied to low all-electric range PHEVs, they can only provide partial compensation for the increase in vehicle fuel consumption that is caused by delaying charging until off-peak periods. For high all-electric range PHEVs, TOU rates are very effective at incentivizing off-peak charging of PHEVs. In summary, achieving the goals of controlling the energy consumption of many PEVs cannot be achieved solely by incentivizing off-peak charging through TOU rates [31].

These results do not necessarily suggest that an increase in peak load is inevitable with the introduction of PEVs. Instead of the smart grid being used to enable consumer controls, punitive pricing structures, and price volatility, smart grid must be used to engage the consumers in understanding how they can improve the sustainability and economy of the vehicle/grid systems. Consumer education and real-time information exchange between the utility and consumers will be a critical component of controlling the energy consumption rate and timing of plug-in vehicles.

3.5.3.3 Transactive Energy Support

Implementation of time-of-use rates changes the consumption habits by shifting the demand from expensive peak hours to less coincident hours, but the dynamic pricing provides a better alignment of consumption with real-time conditions. Under real-time pricing, EV chargers wait for lower electricity prices, particularly if the difference between the time needed for the EV to reach full charge and the time available before the next departure is large. The role of electric vehicle demand response is to facilitate a cost-effective and emission-minimizing alignment between charging demand and available energy supply resources. Our interest in demand response for electric vehicles is motivated by the fact that the EV load is inherently different from other deferrable loads. The EV load management will potentially improve the capability of the demand response program because: (1) the EV charging load can be delayed for relatively longer time than thermostatically controlled loads, (2) EVs can potentially feed electricity into the grid, (3) EV chargers are physically located where other flexible electric loads may not exist, (4) charging stations are equipped with controls that can provide frequency/voltage regulation service, and (5) the power factor of the EV load differs from other flexible loads, which is valuable from the operation point of view.

In order to make use of the charge flexibility, a charge control strategy using the transactive control paradigm was examined in [32]. Transactive control is related to the concept of agent-based control, which refers to methods that control agents’ collective behavior via a limited number of inputs. Transactive control can be considered as a special type of agent-based control for agent-based systems where the agents are able to perform economic transactions [33]. This strategy evaluates the willingness of an EV to buy energy (and potentially to sell energy under the vehicle to grid technology scenario) in real time. Every EV submits its willingness-to-pay price to the local utility, which aggregates these prices and clears the market given the available supply resource. If an EV’s offer price was above the cleared price, it charges at full capacity; otherwise, it forgoes charging until the next market cycle (e.g., every 5 min). The willingness-to-pay price is computed based on (1) the expected mean and uncertainty of electricity price in the time window that the EV expects to be plugged-in, which is periodically provided by the utility to every individual vehicle, (2) the remaining time to departure, (3) the battery state-of-charge, (4) the charging station’s characteristics, and (5) the EV owner’s comfort control setting, which helps the charger satisfy the consumer’s anxiety about having a full charge at the time of departure.
3.5.4 Case Study: EV and PV Participation in the Retail Real-Time Market

Analysis of electric vehicle charge control strategies requires detailed simulation of charging times and locations. To simulate EV load on the power grid, a mobility model is required to represent driving/parking habits, which differ from one region to another and from one season to another. A mobility model is usually based on driving diary of conventional vehicles, including daily trip departure times, arrival times, and traveled distances. It is reasonable to expect that as electric vehicles become more common, data from these vehicles will be more widely used in place of today’s survey. Often, the sample size of the surveyed vehicles is too small or the length of driving diary is too short, and it cannot accurately or generally represent needed driving patterns. One solution is a statistical method that employs copula multivariate probability distributions [34] to produce a larger sample population spanning multiple days, with the same statistical properties, including correlations between driving parameters found in the original under-sampled population.

A case study of 50 homes with both PVs and EVs on a capacity-constrained feeder was considered to demonstrate the performance of the transactive charger control strategy. Three charging scenarios were considered (Figure 3.10): the V0G scenario assumes chargers begin charging as soon as vehicles are plugged in, unless the real-time price (RTP) exceeds the customer’s maximum price to prevent feeder overloading. The V1G scenario assumes chargers only charge when the RTP is below the customer’s willingness-to-pay price. V2G scenario assumes that charging is like V1G but a vehicle also discharges when the RTP is above the opportunity cost of recharging later, given the expected average price for the remaining time to departure, with comfort setting considered. Notice that the battery degradation costs are neutral with V1G, but is impacted by V2G.

We assume the residential rooftop PV panels have power capacity normally distributed about a mean of 2 kW with 0.1 kW standard deviation truncated at ±3 SD. The PV generation profile used is for a July day in Victoria, BC (~48° N latitude) with intermittent cloudiness, using data available at www.victoriaweather.ca. The general assumptions for this case study are shown in Table 3.4 (more

![FIGURE 3.10](image) Household load and rooftop solar PV with vehicle-grid integration scenarios: uncontrolled charger (V0G—a), unidirectional price-responsive charger (V1G—b), and bidirectional price-responsive charger/discharger (V2G—c). (Courtesy of the University of Victoria, BC, Canada.)
information available in [32]). The locational marginal price (LMP) is the electricity price on the feeder, which reflects the underlying wholesale market’s clearing price. It should be noted that the bid price for PV is zero.

The driving diary of the EV fleet is generated using the copula multivariate probability distributions with the same characteristics as the survey data in [35]. Figure 3.11 shows how the correlation between driving parameters is similar for the original population and the new population, which is ~10 times larger.

The RTP resulting from the charging strategies, as well as the total and feeder load profiles, and the corresponding state-of-charge profiles are illustrated in Figures 3.12 through 3.14, respectively, for V0G, V1G, and V2G scenarios.

The results are summarized in Table 3.5 and suggest that the price is generally reduced when control strategies are applied. The peak price time is shifted to later in the evening under V0G scenario but not under V1G or V2G scenarios. Total EV energy consumption is reduced only about 2% using V1G and about 3% using V2G, whereas the net payments are significantly reduced in comparison to V0G. More sophisticated bidding strategies can provide more improvements. It should be noted that non-EV flexible loads, such as HVAC can also actively participate in the real-time pricing in parallel with the EV load, but because the purpose of this simulation was to highlight the impact of the EV load, the flexibility of other loads was precluded.

### 3.6 CONSUMER DEMAND MANAGEMENT

The management of energy demand at the consumer has been the focus of research and debate for several decades. Consumer demand management takes many forms driven by utility incentives for consumers to reduce overall energy usage or to change energy usage patterns. Widely used terms for consumer demand management include energy efficiency, energy conservation, demand response (DR) management, and demand-side management (DSM).

A major challenge for a utility regarding supply and demand of electricity is that the load on the system is not constant and the utility must try to efficiently dispatch generation to meet the load on the system at various times during the day. Utilities typically have various generation sources, such as coal-fired plants, gas turbines, hydroelectric power, or power purchased on the open market, that cause the utility to incur different costs. The cost to deliver electricity to customers on the grid is related to the change in load and supply over time, and any changes in the operation of the grid and available generation sources. Changes in supply include outages of generation and transmission and changes in supply from energy sources, such as wind and solar
FIGURE 3.11 Case study driving patterns: original population (left) versus new population (right): departure time and daily commuted distance (top), departure time and arrival time (middle), and arrival time and daily commuted distance (bottom). (Courtesy of the University of Victoria, BC, Canada.)
photovoltaic (PV). During peak energy demand or major changes in supply, higher cost generation sources are used, such as gas turbines, which result in a higher cost to supply required energy grid needs. During the lowest demand periods, lower cost generation, such as nuclear, hydro, and coal-fired power plants, are the primary sources of electricity. A traditional way to bill customers for electricity is to charge the average price to supply electricity throughout the year and to
measure energy consumption in terms of non-time-differentiated energy (kWh) use over a period or weeks of months.

It may seem counterintuitive for a utility to implement measures that reduce consumer consumption since it reduces the utility revenue. However, in some cases, the reduction in energy consumption during peak, load periods can provide significant operating and financial benefits to a utility. This may translate to avoiding grid congestion, or the ability to supply electricity to customers during contingencies, such as when generation is unreliable. In the long term, it may also help defer grid upgrades when this reduction of energy consumption comes to the grid as a cost less than the annualized cost of the grid investment. But also, importantly, a grid with a growing portion of local customer generation changes the network planning activity and associated spending. For example, in some areas the network operator may prefer not to upgrade the grid when forecasts identify that the constraint will be short-lived (e.g., 3 to 5 years) and will disappear with increased customer local generation adoption trends. This shift of peak electricity may result in significant reductions in capital investment and operating costs, while maintaining grid reliability. Many retail electricity suppliers currently implement specific usage rates or charges for industrial and commercial customers that

### FIGURE 3.14
Case study in V2G scenario: price (a), load (b), and state-of-charge (c). (Courtesy of the University of Victoria, BC, Canada.)

<table>
<thead>
<tr>
<th>Output</th>
<th>Unit</th>
<th>V0G</th>
<th>V1G</th>
<th>V2G</th>
</tr>
</thead>
<tbody>
<tr>
<td>RTP mean</td>
<td>$/MWh</td>
<td>128.14</td>
<td>76.86</td>
<td>76.83</td>
</tr>
<tr>
<td>RTP stdv</td>
<td>$/MWh</td>
<td>146.30</td>
<td>26.94</td>
<td>26.92</td>
</tr>
<tr>
<td>RTP peak time</td>
<td>HH:MM</td>
<td>20:40</td>
<td>15:25</td>
<td>15:25</td>
</tr>
<tr>
<td>Energy</td>
<td>kWh/EV.day</td>
<td>22.27</td>
<td>21.82</td>
<td>21.59</td>
</tr>
<tr>
<td>Charge cost</td>
<td>$/EV.day</td>
<td>4.70</td>
<td>1.51</td>
<td>1.49</td>
</tr>
</tbody>
</table>
include some type of maximum demand component and corresponding fee or penalty for consumption beyond agreed-upon levels.

### 3.6.1 Demand Management Mechanisms

Demand management is generally based upon actions on the consumer side of the meter that reduce consumer load, invoke energy efficiency, DR, distributed generation (DG), or energy storage. Use of the full set of demand management options is also called integrated DSM (IDSM) [36]. Energy efficiency measures alone generally focus on reducing total energy consumption of consumer loads, such as lighting, space conditioning, appliances (e.g., refrigerators, air conditioners, hot water heaters, washing machines, dishwashers), and variable speed motors. Instead, IDSM is an approach to offer customers a full suite of demand-side opportunities.

One part of this, DR, typically refers to reducing consumer electricity usage at specific times during the day, week, or season. Historically, DR has been used to reduce electric usage during peak load times. Reduction in the peak load typically results in deferral of the energy used to an off-peak period. Alternatively, peak load reductions can effectively reduce the load on the system altogether. In recent times, DR has taken several forms, such as voluntary curtable load, behavioral-based response, price (or incentive)-based response, or event-based response.³ An early form of DR is direct load control where utilities could remotely control consumer loads, such as water heaters and air conditioners to turn them off during peak load.

The idea that the demand side of the grid can be managed and demand can respond to information and to signals from the utility is not new. Still, in most markets, demand remains unresponsive to price signals from suppliers or the suppliers may not yet provide demand signals. Both direct load control and price response are increasingly being considered or piloted in various locations. To illustrate, consider the impact of higher gas prices on the amount of air travel or the type of car you consider purchasing. If prices go up a few cents per gallon, you might not care, but when gas prices double, or triple, or even go up by an order of magnitude, your behavior is more likely to change. Presumably, most consumers will shift their behavior or respond in some way as prices change. As an alternative approach, customers may be offered incentive payments in lieu of high prices as a method to encourage demand reductions. In markets where end customers are not exposed directly to high wholesale prices (e.g., Australia, where wholesale prices can go up to AUD$14,000 per MWh), retailers, if exposed to these prices, may choose to engage customers and pay them to reduce load.

If load reduction measures can be encouraged through customer incentives, information, pricing, and technology, the costs to provide the capacity needed for reliable electric service can be significantly reduced. In these ways, a portion of the burden of reliability and the risks with power outages can be shifted to the consumer who will either directly or indirectly realize the benefits. As consumers more cost-effectively manage their consumption through load response, overall system costs can be reduced. For example, with customers enrolled in peak load response in ISO-NE, the system reserve margin may be lowered 10% or more [37]. Correspondingly, this is expected to reduce the probability that peak load would exceed power availability by between 10% and 50%. This reduction in peak capacity may reduce ISO-NE supply side costs by as much as 8.5%. Thus, with an incremental amount of demand management, significant electricity cost reductions are possible. DG installed at the consumer site is another effective means to reduce load demand on the grid seen by the utility. DG generally includes any generation at the customer premises, such as solar PV, wind turbines, fuel cells, combined heat-and-power, and diesel generation or microturbines.

³ On the one hand, voluntary customer curtailment can reduce loads but is usually paid only an energy price ($/kWh) for such reductions. This behavior is neither certain nor predictable. On the other hand, sophisticated electronic controls enable rapid dispatchable load reduction at a specific location. These certain, predictable actions to lower loads may be in response to network operating events or changes in generation pricing.
Some of the DG is considered *must-take* as it is simply put on the grid whenever electricity from these sources is produced. In other cases, it has become dispatchable\(^4\) by either the utility or the ISO who can determine when consumer sources are connected to the grid. When DG provides power to the grid, it may be *net-back-metered* (credited at retail rates), paid or credited at wholesale prices, or valued at some other contractual or tariff regulated rate. If the DG is dispatchable by the utility or the ISO, consumers may be paid for both availability of the distributed energy resources (DERs) as well as additional incentives when the resources are called upon. Larger-scale nondispatchable DG, such as wind power or PV electricity, are generally paid an energy value but are not considered to provide capacity benefits or avoided transmission and distribution (T&D) benefits as they are variable in nature and, thus, are uncertain resources. This is changing, however, as some renewable resource deployments (e.g., wind and PV) are integrated with battery storage to create a reliable source of energy. Importantly, the combination of non-dispatchable renewable resources with dispatchable loads and DERs in a portfolio approach can greatly enhance the capability of the former resources to contribute to the overall load curtailment goal. Reliability of delivery, in this case, will be strongly correlated with weather and how it affects the availability of these resources and increase in load.

Energy storage devices at a consumer site can take power from the grid (to be charged) and provide power back to the grid (discharge) at critical times, or at least offset the amount that is being drawn from the grid. Accordingly, storage can be dispatched to gain market benefits and take advantage of low-cost power (for charging) at times when grid reliability and costs are less consequential, or when a renewable resource is generating in excess and exporting to the grid at low cost. The ability of storage to perform market arbitrage, as with DR, depends on the speed of the response and the availability of the storage when grid needs and market prices are greatest. Storage may be controlled through voluntary (manual) behavioral response or automatically with use of event- or price-based triggers. This suggests that for storage to be of greater value, advances in control algorithms and grid/market interface technology are a high priority. Energy storage can serve many purposes to meet peak loads, variability of renewable generations, or another grid dispatchability needs. Increased use of storage is expected to provide capacity availability, energy, voltage support, and frequency regulation. It is considered a flexible resource with significant market opportunities. Batteries can be utilized in various formats. Larger batteries are being piloted in substations and to support large PV or wind installations. Smaller batteries are being installed as community energy storage (CES) and technology is being developed that can utilize energy backfeed from vehicle batteries. Virtual power plants, aggregating a thousand or more small residential batteries, are also being piloted to mimic the outcomes and benefits that a larger battery can deliver.

### 3.6.2 Consumer Load Patterns and Behavior

At the same time, every day as people get up and go to work and as industry and commerce begin, electric power systems ramp up to meet demand. The electric grid sees predictable changes in load over the course of each day depending on the type of load and various other factors, such as the day of the week, temperature, etc. This results in a series of daily, weekly, seasonal, and annual cyclical changes in load and load peaks. In each case, the utility must provide sufficient generation and transmission/distribution capacity to ensure that demand is fully met in all circumstances.

During the hottest hour of the hottest day in the summer, some utilities experience an enormous demand for electricity, caused by air conditioning units, that the utility must meet to avoid a local brownout (low-voltage condition) or a system blackout (complete loss of voltage). These situations can be even more extreme when some of the generating assets are undergoing maintenance or are

\(^4\) Dispatchable resources are those available to be turned on and synchronized to grid frequency or can be turned up or down to vary generation capacity, in response to grid operator instructions. Non-dispatchable resources cannot respond to grid operator instructions, so are considered *must-take* or may be *baseload* resources.
out of service. To meet these few hours of “peak demand,” the utility must build or have access to enough generation and transmission/distribution capacity to meet the system peak. However, much of that capacity remains unused during the remainder of the year. In fact, for much of the year, electricity demand does not approach the level of the annual peak. In countries with extensive (one distribution transformer serving 50 to 150 customers) low-voltage networks, a quick and large uptake of solar PV (e.g., Australia, with state level penetration of almost 30% in the states of Queensland and South Australia) by customers may cause the reverse problem, or local voltage rise. In this case, the distribution network will also need to have enough capacity to absorb this energy and deliver it upstream.

Load shapes describe the changes in load on a daily or seasonal timescale. Most load shapes are typically represented as an average hourly energy use, for example, kWh/h (Figure 3.15). However, seasonal load shapes are sometimes represented as peak values, for example, MW, even though sometimes that peak value is obtained from the maximum of an average diurnal load shape, i.e., MWh/h. In either case, the load is effectively a power value and not an energy value.

There are some important characteristics of load shapes that must always be considered when they are used. First, the difference between summer and winter lighting load shapes is greater the further the load is from the tropics. This means that any load control system that is affected by diurnal phenomena, such as temperature or insolation, is going to vary more seasonally the further the location is from the equator. Second, for the same outdoor temperature, air-conditioning loads are typically higher in humid climates than dry climates. This means that air-conditioning control strategies may tend to yield greater benefits in humid climates than they do in drier climates. Third, higher-income regions typically have higher loads per capita than less affluent areas. Fourth, commercial loads may be less dependent on climate and weather than are residential loads. Commercial buildings’ cooling systems are more dominated by internal heat gains from lights, computers, and people, and they have less exterior surface area per square foot of floor than do residential buildings. Fifth, industrial loads are also sensitive to economic conditions. When the economy slows, the first things to slow are typically the factories. Sixth, agricultural loads are highly seasonal and sensitive to weather. Water pumping and refrigeration are driven by the growing season in any given region. Seventh, load shape data can change significantly over time because of evolving energy efficiency standards and consumer purchasing habits. Much of the load shape data from the 1980s are still being used because of a lack of newer better data. But the penetration of consumer electronics into the residential market has changed substantially since then, even though the efficiency of appliances

FIGURE 3.15 Example diurnal load shape. (© 2012 Pacific Northwest National Laboratory. All rights reserved. With permission.)
has improved significantly at the same time. Eighth, the composition of the load has changed over the years, particularly due to an increase in consumer electronics and motor loads. Ninth, because lighting efficiency programs have been successful in recent three or four decades and new loads have emerged, lighting load has become a smaller fraction of the total load. In contrast, refrigeration, washing and drying loads may experience a “rebound” when high-efficiency appliances come equipped with new features that can consume more electricity. And finally, the quick uptake of customer-owned generation (e.g., rooftop solar PV), such as in Australia and California, and the associated variations induced through seasons and weather are creating a “negative” element to change the overall load profile.

One way to visualize utility peak loads is to take all the hours in a year and the corresponding maximum load in each hour and then rank them by the load demanded. Graphing this from the hour of the highest load to the hour of lowest load produces a “load duration curve,” which is shown in Figure 3.16.

The figure immediately makes evident that the slope of the line does not remain constant. Rather, the slope is steeper at the left end and at the right end of the graph and less steep in the middle. This signifies rapid change in power demand as you consider the top 1000 load hours and lowest 1000 load hours of the year. Figure 3.16 labels a few notable features of the load duration curve. In addition to the peak shown in this curve, the response of consumer loads can also add value when utilized to compensate for variations in output from renewable energy sources. The most common use of a load duration curve is for planning studies, when planners estimate the number of hours per year for which a system resource must be allocated. The load duration curve can also be used to estimate the maximum amount of load that should be curtailed during a certain period. Although from a generation mix perspective, this planning activity will essentially look at aggregated demand throughout the network from a network assets perspective. Planning focuses on the smallest transformers and other distribution assets since their suitability to deliver electricity reliably will depend on the localized load curves.

While the load shape describes the amount of load that is present at any given time of day and day of year, that description is not, by itself, sufficient for the study of loads in the context of the smart grid. The load ramp time, duty cycles, and periods of those cycles are also very significant when load control strategies seek to modify them. It is possible to measure directly both the duty cycle and the period of loads using end-use metering technology. However, end-use metering is quite expensive, and the data collected about any given device are often the superposition of the device’s natural behavior and other driving functions, such as consumer behavior. So, it is often very difficult to clearly identify the fundamental properties of each load. Furthermore, for any time-domain

![Figure 3.16 Typical load duration curve. (© 2012 Alex Zheng. All rights reserved. With permission.)](image-url)
models where the load aggregate is a consideration, not only the duty cycles or probabilities of devices must be considered, but also their periods and state phases, as shown in Figure 3.17.

In such cases, the state of a single device is the timing of the device’s on event in relation to one complete cycle. Hence, it may be more complicated to aggregate devices with differing usage patterns and functional power cycles. This is important in demand management where utilities need to consider the diversity of consumer load patterns when modeling loads.

### 3.6.3 Conserved Versus Deferred Energy

Load managed by DR can be separated into two parts—conserved energy and delayed energy. In some instances, the load that DR turns off at a designated time is not “recovered” or deferred entirely for use later. This permanent reduction in energy use due to short-term reduction in demand is referred to as conserved energy, because the net impact is equivalent to having never used that energy in the first place. However, not all the consumer load reduction is completely conserved. For example, although loads from lighting may not need to be made up for later, shutting off a hot water heater or air conditioner for a short amount of time may result in additional loading later. This “bounce-back” effect can sometimes result in secondary peaks later in the day when the entire curtailed load comes back online. This energy consumption is known as deferred energy, or the “snap-back” effect, because it still occurs but later. Consumer load reduction needs to be managed carefully to ensure that it does not create artificial peaks that are costly to manage because of deferred demand for energy returning later in the day. Utilities have a variety of methods for managing deferred energy, but most methods are essentially different ways of staggering the return of consumer consumption to full load.

From the perspective of load behavior, demand management has two mechanisms to offer utilities and customers (Figure 3.18). The first is energy efficiency or energy conservation. These strategies reduce the total electric energy consumed by a customer. Typically, these include (1) reducing total runtime, for example, by lowering a thermostat; (2) reducing load during operation, for example, by retrofitting higher efficiency equipment; and (3) substituting fuel sources, for example, replacing central fossil-fueled electricity with distributed renewable sources. The primary benefit of energy
conservation is to allow the utility to avoid the cost of acquiring new sources of energy or deploying new network assets to meet growing demand. Although a utility’s primary incentive is to increase revenue from energy transport and sales, a significant fraction of a utility’s costs includes the acquisition and financing of new energy sources and network assets. New energy resources or network assets can often be so expensive that the effect on rates is too great for consumers to bear. For example, if a utility forecasts a 50% growth in demand over the next 10 years, that would result in a 25% rate increase, but it can implement an energy conservation program that reduces that growth to <10% over the same period without a rate increase; the obvious choice is the conservation program.

The second is peak load shifting. This strategy reduces the peak load on the system by shifting coincident demand to non-coincident times, for example, by using energy storage. The primary benefit of peak load shifting programs is that they allow the utility to avoid the need to build new system capacity that does not come with a corresponding increase in energy sales revenue. Adding capacity is typically a very capital-intensive proposition for a utility, so any program that can move load off peak without reducing revenues from energy sales is attractive.

As a rule, strategies that reduce energy consumption are supported by existing utility DSM programs. These programs are not generally considered smart grid programs in today’s sense of the
word because (1) they are already widespread, and (2) they do not require information technology (IT) to realize most their benefits. In contrast, peak load shifting programs require accurate and timely information to operate effectively, particularly if incentive signals, such as prices, are to capture all possible opportunities and reconcile any contradictory signals that may persist. One exception is conservation voltage reduction (CVR). Given the right mix of load characteristics, CVR can be used to maintain voltage levels between allowed maximum and minimum ranges, by using smart grid technology to monitor, manage, and reduce voltage, producing an overall conservation effect.

The focus of most advanced load modeling research is on those load behaviors that are affected by or can directly participate in smart grid technologies. Hence, most recent load modeling research primarily addresses load shifting behavior and other behaviors that respond to relevant signals from utilities or from the bulk system.

### 3.6.4 Anticipated Energy

Load managed by DR can also seek to deliver the opposite outcome—to anticipate consumption that would occur later in the day. For example, in a network with residential areas with high penetration of rooftop solar PV, in low load/high generation situations, the export of distributed generation may be too large for the local network assets to handle, leading to the need for early asset upgrades to maintain network and asset reliability. In these conditions, it will be beneficial to the network operator to have DR bringing flexible loads, such as hot water heaters, ice precooling, and pool pumps, to consume part of that excess reverse electricity flow. This consumption would occur at another time but what effectively is attempted is to bring some of the consumption forward with no disruption to the customer. This nontraditional form of DR has been explored in high solar PV penetration grids, such as the case of some states in Australia and in California.

### 3.6.5 Utility-Customer Interaction

There are several ways that customers can use demand management. Generally, consumers need to know what loads they want to reduce, and utilities need to provide customer participation options that may include advanced metering and market pricing data. With a smart meter or any other connected load interface device in place and either advanced electricity pricing or incentive schemes (e.g., payment for the ability to reduce customer load) that are communicated to consumers, automated DR can be employed to directly trigger load reductions, also called auto-DR, when specific price levels are exceeded. A major aim of auto-DR is to enable DR through a preprogrammed response, for example, to reduce appliance loads at specific price levels, so that consumers can directly participate with minimal effort and gain the benefits of DR. It is expected that as IoT connects more and more loads, consumers will be able to choose from a multitude of strategies for their DR participation, which can involve choosing between more “comfort” settings or more “economic” settings, according to consumer priorities for the day and time of the event. Alternatively, customer demand management may be employed manually using “behavioural DR,” where the customer receives notice of an upcoming load-reduction request, and through an appropriate incentive structure, makes decisions on their load usage during the event, or even in some cases for residential customers, choosing to leave the house temporarily to reduce consumption to a minimum. This back and forth between market prices, customer preferences, customer incentive, the meter, and consumer loads will enable a more complete electricity market, particularly as loads can increasingly respond to prices as much as the supply-side responds to price. This fully participatory DR market will provide the needed complement to the supply-side of the electricity market, resulting in greater market efficiency. In contrast, today’s largely supply-only market leaves electricity prices

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5. This is known as a dual, supply-demand market equilibrium, as compared to the predominantly supply-side only electricity market equilibrium. See Ref. [38].
unresponsive to loads, and consumer response is not a factor. Not only will a more dynamic consumer load and supply-side market be more efficient and increase reliability (reduce blackouts and brownouts), it will reduce market price volatility and the potential for market power manipulation.

Figure 3.19 illustrates a set of steps and information flows between the utility or market and the consumer, focusing on the use of price signals. The electricity market takes energy information and provides price signals, which are sent to consumers by advanced smart meters or other communications mechanisms, such as cable TV, phone line, wireless networks. Consumers can respond extemporaneously or through automated technology to direct incentives and market prices. Smart consumer devices, such as lighting and appliances that can respond to price signals to turn off, reduce, or defer or anticipate load, will provide the basis for consumer DR enablement and help respond to market prices and customer information. One example could utilize home area network (HAN) technology and open standards. The smart meter, in addition to its digital time-based metrology, can provide advanced information flow to the utility, the market, and to customers. This can be especially useful for the electricity market and the grid operator to verify the availability of DR as it prepares to respond to system contingencies and reduce loads in response to prices. However, the smart meter will likely not be the only central point for this information flow since other providers that don’t own metrology or have more cost-efficient communications solutions (e.g., existing wireless or cable providers) may utilize other strategies to deliver a DR outcome. In fact, customers might adopt smart thermostats to optimize their own consumption, without having DR as an intended goal, and these thermostats might access the Internet and be optimized via cloud applications. The installed base of these thermostats could then provide a platform to implement DR without using the meter as a gateway into the customer’s premise.

### 3.6.6 Value of Demand Management

Utilities benefit in many ways from demand management programs: (1) avoiding dispatch of expensive peak generation units, (2) deferring long-term capital investments in excess generation and T&D capacity, (3) reducing carbon footprint by using more efficient units, (4) increasing system reliability, and (5) savings from lower energy use during high-cost times, (6) additional tools to support the growth of renewable energy (e.g., wind and solar) for which the power output varies.

The value of demand management is usually compared to opportunities to defer or fully avoid supply-side and grid alternatives that are constructed. The resources and related costs deferred or avoided include electricity generation (power plants), transmission lines, distribution, customer costs, and environmental pollutants, including $SO_2$, $NO_x$, and $CO_2$. Where competitive markets exist for deferred or avoided resources, market prices can be used to value demand management.

Demand management provides grid support functions, such as contingency response, reserves, and frequency control. Demand resources can be called upon to respond to disturbances on the
system to prevent and mitigate outages. In addition, by providing reserves and frequency regulation, demand resources can enhance the stability of system operations without the need for additional generation capacity. In California, for example, if only 20% of the state's retail demand in 1999 was subject to time-based pricing, and with only a moderate amount of price responsiveness, the state's electricity costs would have been reduced by 4% or $220 million. The following year, in 2000, electricity prices were more than four times as high, and the same amount of DR would have saved California electricity consumers about $2.5 billion—or 12% of the statewide power bill. These, and other estimates of benefit potential, were presented to the U.S. Congress in a senate-requested report by the General Accounting Office in 2004. The PJM Interconnection estimated that during the heat wave of August 2006, DR reduced real-time prices by >$300 per megawatt-hour during the highest usage hours, estimated to be equivalent to >$650 million in payments for energy. Many utilities, such as PG&E and Southern California Edison, have been able to use demand management programs to help justify recovery on extensive AMI rollouts.

Demand management can also make important contributions to addressing climate change and other environmental issues. One way that it does this is by enhancing and reinforcing customer energy efficiency, the accepted cornerstone of emission reduction policies. With DR technologies, customers will receive information on their electricity usage that they have never had before and receive it in a timely manner such that it acts as feedback to reinforce their energy management efforts. Furthermore, they will have price and rate options or incentives that will stimulate them to be more efficient and target energy consumers. DR technologies will be the answer to the question: “How can you manage what you cannot measure?” A report in 2007 from the Brattle Group [39] has shown that even where customers are not on time-differentiated rates, they may reduce their electricity usage by 11% just by being more informed and understanding better how and when they are using electricity. The report suggested that if DR were implemented nationwide in the United States using only existing, cost-effective technologies, peak load could be reduced by 11.5% (assuming nationwide consumer acceptance of such a program). The study concludes that a more conservative nationwide DR program would result in a peak load reduction of 5%, which would correspond to nationwide savings of $3 billion each year, or $35 billion over the next two decades. This figure does not include other benefits, such as lower wholesale electricity prices, improved reliability, or enhanced customer service.

**SIDE BAR: BENEFITS REALIZED: DEMAND RESPONSE SAVES THE TEXAS GRID FROM BLACKOUT**

On February 26, 2008, the Texas grid suffered a significant increase in demand (4.4 GW) due to colder than expected weather coupled with a decline in wind power (1.4 GW) and an underdelivery of power from other power sources. This sudden strain caused a drop in system frequency, which triggered emergency grid procedures into action. Because of the system-wide lack of generation capacity, the Electric Reliability Council of Texas (ERCOT) turned to their demand response (DR) program, also known as Load acting as a Resource (LaaS), to help bring demand back in line with supply. These loads consisted of large industrial and commercial users who signed up in advance to curtail their electricity use for payment during grid emergencies. The cost of dispatching these resources is significantly lower than dispatching peaking gas turbines, whose costs can be as much as an order of magnitude higher. This program enabled an estimated 1.1 GW of DR resources within a 10-min period, helping to stave off a blackout. Most of these loads were restored after an hour and a half [40,41].

The economic benefits of demand management have historically been based on grid capacity needs and demand management operational capabilities. In many places, demand management has been used only during system emergencies when generation capacity was scarce. It is increasingly
accepted that demand management can reduce the need to purchase high-cost, capital-intensive infrastructure (e.g., generation and transmission capacity) that is used to preserve reliability, and reduce uncertainties in loads and system conditions. This contrasts with earlier versions of demand management programs that had limited availability and uncertain response times when called. Still, these earlier demand management programs did offer significant operational certainty to ensure that specified load reductions occur.

In the last three decades, demand management has been primarily viewed as a means to bolster grid reliability during emergencies. More recently, demand management is viewed as a flexible resource to respond to a full set of market needs, mitigate price and congestion needs, and respond to a series of needs for specific reliability and energy-based services. The Federal Energy Regulatory Commission (FERC) in the United States has provided rules to enable demand management to be treated comparably with supply-side resources, which means that demand management can be used, and compensated, in the same specific ways as supply-side resources. Demand management, in response to price or reliability needs, is no longer just for emergency peak load management. Demand management can now be used for the full set of market opportunities, on the one hand, to respond to variations in renewable energy supplies and, on the other, to reduce fuel costs in power plants.

The long-standing goal of many in the demand management industry has been to reduce the peak loads and increase loads during minimum load times, and increase power plant fleet utilization, that is, increase the fleet capacity factor. With greater use of demand management, daily load curves would have lower peaks resulting in lower average electricity costs. With a flatter load profile, grid operators and utilities can use the more efficient plants more hours per year.

Demand management can provide major wholesale benefits and is increasingly used to derive benefits that are monetized in organized electricity markets. When electricity market generation is scarce or prices are high, load reduction from demand management is valuable. Many demand management resources can participate directly in organized markets, though energy efficiency is largely the exception.

The basic competitive wholesale market services that demand management, DR, and energy storage may participate in are as follows:

1. Resource adequacy (planning reserve), which can be defined on a locational (subregional) basis (e.g., 15% of total planned load)
2. Operating reserves, including spinning and non-spinning generation reserves that must be available online within 10 min (e.g., 7.25% of current hourly load)
3. Frequency control or automatic generation control to ensure that regional frequency (on a subsecond basis) is maintained
4. Emergency capacity, which may include capacity market requirements (e.g., in PJM and ISONE)
5. Energy, on a zonal, nodal, instructed, or distribution circuit basis, including providing supplemental energy needed to “back-fill” operating reserve requirements
6. Congestion management for locational “out-of-merit” or “out-of-sequence” conditions
7. Energy price mitigation, particularly on a locational basis, to reduce energy prices, such as when scarcity conditions exist

Organized competitive markets provide most of these services in separate markets for day-ahead, hour-ahead, and “real-time” trading and scheduling. Power generation plants and demand management services that comparably satisfy necessary conditions can operate in many different markets on a given day. A major increase in the need for ramping capacity for grid balancing is in response to the large amount of variable renewable resources on the grid, particularly wind generation and PV generation.
Demand management can also be used for load management at specific locations on the distribution system. At a time when energy demand is flattening but demand peaks still exist, building network assets may not be the most economical and efficient option. In areas where the network component of consumer retail bills is high, grid operators will face government pressure to manage growth. Regulators may seek non-network options that have better financial returns. The rapid deployment of customer self-generation, such as rooftop solar PV and very soon batteries are also further complicating the work of planners and utilities in general. Consumer choices in response to higher rates may render network upgrades stranded when these choices contribute to reducing the peak demand that motivated the upgrade in the first place. This is a new element or rather its effect has become more pronounced with the advent of more efficient appliances, solar PV, and energy storage.

**Case Study: United Energy Partners with Demand Response Provider to Use DR for Network Support**

The Australian network services provider United Energy has entered a partnership with a Demand Response Service provider Greensync to deliver a demand response and energy storage project that will allow the deferral of a network upgrade in the Mornington Peninsula. The evaluation of the options to serve the constraint was done under a regulatory process designated a Regulatory Investment Test—Distribution (RIT-D), which is managed for compliance by the Australian Energy Regulator (AER). This process undertakes a cost-benefit analysis to ascertain the net-present-value (NPV) of all proposed solutions whether they involve the building of network assets or a non-network option, such as Demand Response. The network upgrade is estimated at AUD$29.5 million for a need to deploy in 2022. Three alternatives were compared: A pure network augmentation, a hybrid DR and network augmentation, and a generation (diesel genset) network support. The winning hybrid DR comprises a DR service running for 4 years starting in 2019 with load curtailment of 11.5 MW, growing up to 13.1 MW in 2022, followed by network augmentation in 2022. Although not eliminating the need for the network augmentation, this non-network demand response initiative will allow UE to delay having to build new infrastructure to meet infrequent high demand in the area.

Although there are several cases of long-standing network support agreements with generators or large loads for network support purposes, this landmark project in Australia is the first public regulatory project that has won by NPV value to deliver DR encompassing households, small businesses, and community organizations, as well as large, medium and small loads for network support [42,43].

The greatest value from demand management is realized when it can serve multiple purposes—such as for the high-voltage grid, customer needs, and the distribution grid. The flexibility of demand management to serve these purposes depends on the hours of availability and the trigger(s) used to activate and, thus, harness the demand management. There is a likelihood that the accrual of these benefits may occur at different times of the days, making the ability to meet multiple objectives difficult to achieve.

The potential contribution that demand management can make to renewable energy development should be noted. In the case of wind energy, a geographic wind resource may not be available during peak demand periods. By matching that wind resource with DR during the period that wind is unavailable, the wind resource may become more viable. Conversely, in periods of excess solar PV generation in the distribution grid, bringing flexible loads (e.g., hot water heaters, pool pumps) to consume that excess generation may allow for more solar PV to be deployed without resulting in the need for network augmentation or the creation of a barrier for customers that wish to adopt the technology. To support high levels of intermittent renewables on the grid, demand management enables
load to follow generation, instead of the traditional model of generation following load. The result is a greater opportunity to replace higher marginal cost and less environmentally friendly resources with a combination of wind (or solar) and DR.

The calculation of benefits for demand management usually depends on (1) whether it can be dispatched (in contrast to voluntary response), (2) the certainty (predictability) of availability, (3) the response times when it is called, and (4) the ability to verify its availability and its dispatchability when called upon.6

The installation of interval metering has been one of the main enablers of demand management and has brought about a greater certainty of demand management availability and performance. Many states in the United States have begun to address demand management cost-effectiveness.7 California has decided that dispatchable demand management qualifies as resource adequacy, which allows it to be more valuable.8 This also means that dispatchable demand management can qualify to provide grid ancillary services called operating (spinning and non-spinning) reserves and emergency capacity.9 Fast responding demand management may also qualify to provide instructed energy,10 which is usually paid for at the highest energy market prices.

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**Case Study: PNNL Olympic Peninsula Project Saves Utility and Consumers Money**

In 2004, Pacific Northwest National Laboratory (PNNL), in partnership with the Bonneville Power Administration, started the Olympic Peninsula GridWise Demonstration Project, which equipped over 100 households with advanced meters, as well as thermostats, water heaters, and dryers that could respond to communications signals from the meter. The software used in the pilot program enabled homeowners to customize devices in terms of choice of the desired level of comfort or economy, to automatically optimize the level of power use based on dynamic electricity prices that changed every 5 min. This DR demonstration project yielded average electricity bill savings of 10% for participants [44].

The project also provided benefits to the utility by reducing transmission congestion during peak hours and the need to build additional transmission. This pilot project showed that the Bonneville Power Administration could successfully defer additional transmission investment for at least 3 years. Called “GridWise,” this demonstrated that intelligence-enabled appliances can reliably and economically be used to alter load profiles in response to real-time price signal, and reduce the need for peaking plants and additional capacity expansion.

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**3.6.7 Beyond Peak Shifting**

The benefits of demand management go beyond mere peak shifting and many times include lower overall levels of consumption—a conservation effect—as well as very large price reduction effects.

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6 The recent DR cost-effectiveness protocol highlights the following operational factors for DR: availability, notification time, trigger, distribution, and energy price. These factors do not directly reflect the requirements to qualify for specific CAISO markets or provide distribution load management, which seem essential for cost-effectiveness.

7 For example, see CPUC ALJ Hecht’s August 27, 2010, ruling in Rulemaking 07-01-041 (DR OIR) to provide guidance on the scope and contents of the utilities’ DR applications. This ruling emphasizes a set of related topics: use of price responsive DR, resource adequacy (planning reserve margin) requirements, integration with the wholesale market, integrated demand-side management, load impact estimates, and cost-effectiveness metrics.

8 Resource adequacy has also been defined as long-term planning reserves, which are needed when other plants and transmission lines do not operate, most typically because of “forced outage.”

9 Operating reserves are short-term reserves to be used within 10 min, typically when generation or transmission outages occur. Operating reserves come in two forms, spinning or “hot” reserves and non-spinning or “cold” reserves.

10 Instructed energy is provided by the CAISO’s electronic dispatch, which requires the generator to be available and respond, and either rapidly increase or decrease generation output as needed.
It is difficult to convey the economic impact of these benefits as they are complex to estimate and are specific to each electricity control area. The Federal Energy Regulatory Commission (FERC) in the United States reports over 50,000 MW in peak load reduction potential from its 2010 survey [45], which is broken down as follows:

- Wholesale commercial/industrial DR potential increased from 12,656 MW in 2008 to 22,884 MW in 2010.
- Utility commercial/industrial DR potential increased by 23% from 2008 to 2010.
- Wholesale and commercial/industrial segments are over 80% of the DR potential.
- Residential DR potential is estimated to be over 7000 MW.
- Four DR programs (emergency response, interruptible load, direct load control, and load as capacity resource) account for 79% of total U.S. peak load reduction potential.

This FERC report also summarizes the market barriers to greater use of DR that regulatory reform may remove or significantly mitigate [45]:

- Disconnect between wholesale and retail markets—pricing is not consistent.
- Measurement and verification challenges with establishment and use of base-line levels of DR.
- Lack of real-time information sharing—retail entities do not share wholesale or distribution system-level information with customers.
- Ineffective DR program design—retail DR programs do not reflect wholesale market realities and benefits.
- Disagreements on cost-effectiveness analysis—the benefits attributable to DR.

The FERC’s estimate of national DR potential broken out by region is shown in Figure 3.20. The gap between business as usual (BAU), achievable participation in DR, and full participation in DR is estimated. These differences reflect varying degrees to which barriers to DR adoption are present.

While demand management at the industrial level has been in place in different forms for decades, at the commercial and residential levels, it is relatively new. This is because industrial loads tend to be larger and more concentrated, making them ideal candidates for curtailment during peak hours. Utilities can easily cut large loads by making only a few calls. But curtailling such high-value loads also risks greater economic harm. Demand management would allow low value, noncritical commercial and residential loads to be turned off with less economic impact.

There are several evolving trends in the industry that hold promise for wider and more active participation from commercial and residential consumers:

- **Improved human interfaces:** Among the many in-home displays recently released or in development, an example is Intel’s Intelligent Home Energy Management Proof of Concept. This features a vibrant OLED screen and integrates traditional thermostat features with energy cost management (through connection with ZigBee compatible advanced meters), home security system monitoring, tasks reminders, and media functions such as video memos [46].
- **Portability of human interfaces:** Smart thermostats now can be controlled by an app on the consumer’s smartphone and are available at all times to accept settings changes, giving its users a variety of control options where the trade-off between cost and comfort can be decided in advance.
- **Lower-cost sensors and communications devices:** Lower-cost sensors and communications devices will make it cost effective and faster to communicate between the utility and the consumer through a variety of channels.
Better energy management software: Google’s PowerMeter and Microsoft’s Hohm energy management software may serve as predecessors leading to new tools for customers to manage their energy use in an online, highly visual environment.

Greater public awareness: Increased public education and concern about environmental and energy issues, especially in the past decade, have driven greater involvement in personal energy use management and demand for information and control over emission sources for both commercial and residential applications.

### 3.6.8 Demand Response Implementation

Key to the implementation of demand response management programs is an integrated set of applications that enable both the utility and consumers to understand and have control over energy consumption. At the utility level, economic DR programs are implemented that offer economic incentives to customers to contain and/or shift their energy demands to better match system-level demand with system supply resources. At the consumer level, home energy managers (HEM) or smartphone apps provide real-time energy consumption information and optimize the operation of connected appliances and energy management devices in the household. The primary objective is not only to provide consumer applications and HEM devices that empower and allow better management of energy consumption without adversely compromising lifestyle but to also allow utilities to optimize rate structures, reduce reserves, and allow greater economic flexibility in the near and long term. Demand management may also be used to mitigate unexpected supply disruptions or overload conditions. During such conditions, customers may be asked to curtail consumption on short notice or utilities may use direct load control to shed consumer loads.
Demand management should not be limited to solutions that are able to suppress or shift demand and alleviate peak load. The vision should be to provide a solution that goes beyond peak shifting and provides flexibility and increased efficiency in managing overall demand. The solution should match generation resources with demand from electricity consumers in an efficient, predictable manner and incorporate the control, integration, and optimization of renewable and other DERs as the adoption of these technologies increases.

The demand response management system (DRMS) is the utility application that manages DR capabilities from the utility down to the consumer. The DRMS also interfaces and operates with other utility operational and information systems, such as EMS, DMS, OMS, customer information systems (CISs), and billing. To be an end-to-end solution, a DRMS needs to have this level of functionality at a minimum to provide real value to a utility.

First-generation DRMSs typically focus on functionalities needed to support peak shifting by obtaining load information from the meter and statistically estimating load availability based on customer enrollment and consumer historical data compared to the load forecast from EMS. Once a DR event is selected, the DRMS sends a basic signal to preestablished groups of customers based on the estimated amount of MWs required. In-home enabling technologies, such as smart thermostats, in-home displays (IHDs), HEMs, and smart appliances, receive the signals and perform the load management activities based on the consumer’s preferences. Two-way communications allow the utility to measure the effect and verify consumer participation in demand management.

As load management technologies advance and the DRMS is integrated with more utility enterprise applications, the DRMS enables the use of DR to support emergency response and virtual generation capability in the EMS. Through aggregation, it estimates demand in near real time and can dynamically select customer groups based on electrical nodes and resource availability. The DRMS also incorporates and accounts for distributed resources such as energy storage, wind, solar, and PHEVs.

The operations component of the DRMS contains all the critical applications for a utility to manage and maximize resources for DR events. These applications include response estimation, dispatch, aggregation/disaggregation, measurement and verification, and reports and analysis.

More recently, the concept of a Virtual Power Plant (VPP) has been used interchangeably with DRMS, where the intended outcomes are the same.

### 3.6.8.1 Load Modeling and Forecasting

For most of the twentieth century, loads were quite simple to understand and represent, even as they grew increasingly unpredictable over the years. The philosophy of power systems engineering is that the purpose of the bulk power system is only to satisfy the load and not to question why it is present or attempt to manage it directly. Consequently, load was treated largely as a boundary condition. In fact, very early electric system planners generally anticipated only three types of loads: constant impedance loads from devices such as incandescent light bulbs, inductive loads from motors, and system losses from cables and transformers. The times and quantities that were present were quite easy to anticipate, and the system could easily meet the need to balance supply and demand by having generators follow the load using voltage and frequency feedback signals.

As a result, with few exceptions, power engineers tended to downplay the significance of load behavior. Load was treated largely as a static boundary condition, even when numerical simulations made it practical to do otherwise. It made perfect sense to keep load a constant parameter in the context of steady-state flow solutions or sub-minute dynamic simulations because (1) that is how the system was operated, and (2) whatever uncertainty was present was both small enough and random enough to be readily addressed by good dispatch practices and the existing feedback controls. At every time scale in between, load behavior simply was not complex enough to warrant much consideration beyond basic forecasting needs.

The first hint of the potential significance and complexity of load behavior came with the cold load pickup problem. This problem arises after prolonged power outages where all thermostatic loads have settled well outside their normal control hysteresis bands and load patterns have lost
diversity. When the power is turned back on, all these devices turn on simultaneously, causing a surge in demand that can far exceed the demand prior to the power outage and even exceed the maximum capacity of the system (which is why it can take several days to restore full service to all customers after a major system outage). This phenomenon is also observed in load curtailment rebounds, which are similar in nature although not generally as severe.

But, it was not until the advent of smart grid technology that power engineers came to seriously consider the potential role that loads could play in meeting system needs. It was realized rather quickly that loads exhibit behaviors that are not simply detrimental to the system, such as cold-load pickup or load curtailment rebound. The same phenomena that give rise to adverse behaviors might also be used productively to support strategies such as bulk system underfrequency load shedding at the end-use level (instead of at the neighborhood level), distribution system undervoltage support, or support of intermittent renewable generation, such as wind and solar.

Economies of scale, regulatory barriers, customer expectations, and a strong preference for centralized command and control in vertically integrated utilities have made it far easier to govern a few large generators than many small loads. So for more than one hundred years, the system was controlled exclusively from the supply side. Understanding load behavior was unnecessary, and with remarkably few exceptions, it remained largely an academic question.

The introduction of smart grid technology, the growth of intermittent renewable generation resources, the surge of local DG such as rooftop solar PV and the advent of intelligent load controls have converged to make loads potentially an equal partner in the electric system’s physical and economic operation. As a result, load modeling has become an increasingly important consideration in the design and operation of smart grid technologies and in the debate about how to host and enable the implementation of renewable resources.

To understand how loads respond to changes in circumstances, utilities must begin by understanding how loads behave in general. Load behavior analysis and modeling require subdividing loads into the main classes that influence the kinds of behavior observed. Primary among these taxonomies is the economic nature of the load, namely, residential, commercial, industrial, and agricultural. For smart grid purposes, residential and commercial loads are the most challenging and interesting. In contrast, industrial loads are not the focus because they have individual characteristics that can be difficult to model, and agricultural loads because they tend to be simple in comparison.

In addition, at least from the perspective of electric system modeling, it is vital to identify the degree of electrification of the load itself. Electrification is typically characterized by end use, that is, the type of device that meets an electric customer’s needs. Not all devices use electricity to satisfy the demand for goods and services, and the fraction of those that do varies according to factors such as geography, demographics, regulatory policy, and long-term expectations for energy prices for the fuels, if any, needed by the various prime movers, for example, steam, water, wind, sun.

Finally, intermittent availability of lower-cost fuels, particularly those that are relatively uncorrelated with electricity prices, can make multifuel systems economically advantageous. From the standpoint of load behavior, these can either be implemented as direct-delivery systems, such as solar water heaters, or be mediated by electricity delivery systems, such as rooftop PVs. The availability and behavior of these systems can influence load behavior as well.

Smart and efficient execution of demand management commands relies strongly on smart measurement and analysis of consumer and market data. Different portions of end-user consumption level are qualified for various demand management programs, such as interruptible load, direct load control, or demand dispatch. Metering of individual consumer load consumption versus an aggregate measurement of the consumer total load provides detailed knowledge on the consumer habits and consumption patterns and enables a more appliance-oriented DR approach with a higher chance

\[11\] One notable exception was the advent of DSM programs focused on energy conservation. These programs address the problem of load growth through conservation measures, such as efficient appliance retrofits and consumer education. To this day, DSM programs remain effective at controlling the net rate of load growth.
of success. This would require smart and efficient analysis of the raw data to extract meaningful information from it for DR purposes. Various estimating and forecasting techniques can be used to develop a reasonably accurate model for consumer demand and provide a forecast for its demand during the future time intervals. The sensitivity of the consumer to the electricity prices can be incorporated into the model to reflect the response of the consumer to demand management events. More complicated econometric models can be developed to account for the qualitative data, such as the personal habits of the individual consumer toward DR events. These models can determine a probability value by which an individual consumer may comply with a demand management event issued by the utility, and if proved reliable, they become part of statistical reliability. This information proves to be very useful in validating the demand management event and determining whether extra measures are necessary. Matching this information with electricity market prices, from the full set of separate market elements, is an additional challenge.

Traditionally, DR programs have been offered to the customers as a set of fixed options with preset terms and conditions. The customer would then pick the program that fits his/her needs the best. There are several attributes that are directly associated with each program, such as the maximum duration of the demand management event, the maximum number of times a demand management event may be issued in a year/month, and the maximum number of consecutive days a demand management event may be issued. Other attributes are more related to the consumer, for instance, the minimum notice for the event. All these attributes could make a difference in the comfort level of the customer participating in the corresponding programs and, therefore, impact the acceptance and success of the program.

With proper modeling of the customer load patterns and habits, it is possible to customize the programs to tailor these attributes to fit customer needs and habits. This will create a wider and more flexible set of program terms and incentives for selection by the customer. More choices can lead to higher customer program participation. With additional choices, a consumer may view the process of selecting the suitable programs confusing, making the selection difficult or even risky. This issue could be buffered via a mechanism that utilizes consumption patterns and habits of individual consumers to propose an optimal program selection to the consumers to create mutual benefits for both parties.

3.6.8.2 Price Signals

Consumer DR can be controlled using price signals. Different rates at different times, implemented effectively, can drive desired end-user consumption behavior. However, unlike the availability cost of other services, such as airfare or hotel rooms, currently the typical electric price to the residential customer is “one size fits all.” Such a price offers no reduction for conservation and no premium for consumption during peak periods. While utilities across the country have used these types of pricing mechanisms to differing extents for some time now, AMI technology paves the way for much greater adoption of dynamic rates and pricing signals for all customer classes—“smart meters” enable “smart rates.” As with any control system, utilities can employ either an open-loop or a closed-loop strategy. An open-loop price-based control strategy generally relies on time-varying prices with the expectation that higher prices lead to lower loads. Several types of open-loop pricing strategies are commonly found and are distinguished by the rates or tariffs they use. Each rate is designed to elicit a different response from customers.

Time of use (TOU): TOU rates have existed in some countries for many decades because they are simple to implement and meter. The peak-time schedule is typically determined seasonally, and it sometimes has a “shoulder” rate that is an intermediate rate between the off-peak and on-peak rates.

Critical-peak pricing (CPP): CPP is like TOU pricing, but instead of having a daily schedule, the CPP is declared only on the few days the utility expects peak conditions to prevail. For this reason, the price on critical peak is usually very much higher than the standard rate. It is not unusual to find the CPP rate is >10 times the standard rate.
Peak-time rebate (PTR): PTRs are like CPP rates, but instead of charging customers more, the rebate works by refunding customers who reduce load on peak. Unfortunately, it is often difficult to determine the savings precisely for any given customer, and solving this problem can lead to complexity in the program implementation.

Dynamic pricing (DP) or real-time pricing (RTP): DP or RTP works by sending customer prices that reflect, to some extent, the variations in prices seen at the wholesale level. Unfortunately, because the fluctuations in wholesale prices can be unpredictable and vary as frequently as every 5 min, RTP can be difficult for customers to respond to without special hardware. RTP is a closed-loop price-based DR control strategy. The implementation of RTP can be difficult to understand, but its flexibility and scalability are very important attributes that have led to growing interest in its use. RTP systems may require DR equipment to be installed in the customers’ homes. The fact that prices change in periods as short as 5 min means that customers cannot be expected to respond all the time. Some may contend that customers will not accept price change more frequently than hourly. For this reason, RTP systems include devices that can respond to prices and interact automatically on behalf of the customer. One very important caveat for RTP is that a customer’s subscription must be voluntary. Some customers may have load shapes that are particularly ill suited to RTP because the unresponsive part of their peak load is highly coincident with peak price. In contrast, other customers may have highly responsive loads on peak and may be able to provide a load of flexible DR to the utility. At the other end of the scale, some customers may not have enough demand on peak for the cost of the RTP system to be justified, and utilities must retain the ability to exclude certain customers from using RTP when they would essentially be free riders or not viable as a DR resource.

From a utility planning and operation perspective, predicting the demand curve for RTP presents an additional challenge, particularly in response to a price disturbance after which the demand response resource may be depleted. From a first-principles approach, there is evidence supported by field demonstrations using transactive control systems [47,48] that the random utility model [49] best describes the demand curves of thermostatically controlled loads that respond primarily to short-term real-time price fluctuations [50].

This demand curve is illustrated in Figure 3.21. In addition, the elasticity of demand is shown, and it is apparent that the maximum elasticity of demand in the short term is not necessarily found in the equilibrium price and quantity. Deviations from the equilibrium point give rise to significantly reduced short-term demand elasticity and can be expected to result in reduced responsiveness in subsequent dispatch intervals.

Regardless of the specific pricing mechanism proposed by a utility, there are two fundamental implications of these changes:

- More active involvement on the utility’s part in helping customers understand what they can do to reduce their usage
- More active involvement on the customers’ part in what they use and when they use it

Smart grid is more than simply new technology. It will have a significant impact on a utility’s processes. Perhaps more importantly, it is also about the new information produced and made available by these technologies and the new customer-utility relationship that necessarily emerges because of these technologies. A critical element of this new relationship is “decoupled rates.” Decoupled rates break the linkage between what a utility charges for power delivery and how much energy the end user consumes. While the costs of generating power are clearly a function of usage, the cost a utility incurs to provide a power delivery system has little to do with how much energy an individual customer typically uses. Public, regulatory, and local government interest in renewable energy sources and DSM programs has never been higher. However, until new pricing mechanisms such as “decoupling” become more common, utilities will continue to have a financial disincentive to encourage their customers to use less of their product. Greater alignment between the end user and the utility interests will result in greater reductions in energy consumption (and emissions).
3.6.8.3 Demand Dispatch

With few exceptions, utilities today rely on manual processes, spreadsheets, and independent software applications to decide if, when, and how much demand resource is needed to support forecasted demand requirements. The demand dispatch application in the DRMS is a decision support tool that provides utilities with recommendations as to when to initiate a DR event and how many customers to include in the event. The demand dispatch tool determines the optimal schedule and resource mix, considering generation costs and the impacts of the rebound effect when providing recommendations for how much DR to request for each given period. The demand dispatch tool should consider optimal dispatch of demand across multiple customer types and pricing programs.

3.6.8.4 Consumer Response Estimation

Load response can be separated into two distinct behaviors: one behavior is a one-time irreversible behavior, for example, a person turns off the lights when leaving home; the other behavior is reversed later, for example, a person defers doing a load of laundry until the next day. Some load responses have both. For example, lowering a thermostat by 2°F for 8 h every day will reduce the heating energy consumption in the short term. But the load will experience a recovery period during which some of the energy savings are lost when the thermostat setting is raised back up again. A comparison of the reversibility of different residential load responses is shown in Table 3.6.

Irreversible load responses reduce overall energy consumption by the amount of load that responds. Irreversible load response is simply a change in the load shape, which results in a net
reduction of both energy and maximum power, as illustrated in Figure 3.18a. Most irreversible load responses require a one-time investment, and the benefit is typically enduring. However, some load responses, such as consumer awareness programs, may appear to be irreversible over the short term, but in fact decay in the long term.

Reversible load response is a change in the load shape that results in a change in maximum power but no net change in energy consumption, as shown in Figure 3.18b. This behavior is typical for thermostatic loads, such as heating and cooling systems. These responses are often called load shifting or deferral. Preheating and precooling are also reversible load responses, but with the opposite sign (i.e., load increase precedes load decrease).

Reductions in consumer real power consumption are typically associated with energy efficiency programs; that is, reducing real power consumption reduces energy consumption for non-thermostatic loads such as motors and lights. In some cases, though, reduction of real power can also reduce peak load, which, from a smart grid perspective, may result in deferred capacity expansion. One caveat is important for thermostatic loads: reduction in real power typically results in increased duty cycle or run time and does not result in reduced energy consumption. This can affect the saturation load (the load at which diversity disappears) and contribute to increased adverse load behavior associated with loss of load diversity, such as the onset of load rebound and real-time price instability.

Many existing direct load control programs do not enable utilities to accurately estimate how much load reduction they will obtain when an event is initiated. As a result, a common strategy is to send a signal to a larger subset of the population to ensure the necessary reduction is met. The impact of the event is evident at the system level; however, there is no direct feedback from premises and very little learning on the impact from one event to the other, making the planning and execution of demand management very inefficient. The lack of feedback also makes estimation of the potential rebound effect after the demand management event more difficult, making the grid vulnerable to a subsequent rebound peak or operational instability. The response estimator function in the DRMS determines the amount of MW and MWh available for DR over a time frame of interest, including the estimated rebound effect. In addition, this estimation can be tied to existing load forecasting tools since there is direct correlation between the two. The response estimator evaluates the likely response from participating homes, as well as their associated probabilities of participation.

### 3.6.8.5 Aggregation/Disaggregation

Aggregation is a necessary component of the response estimator application. The aggregation function determines the total DR available based on customer participation and availability. The aggregation function collects up-to-date metering data from each of the applicable premises to enable as accurate an assessment as possible of the current load state and potential for DR. The disaggregation function identifies the participating customers for each pricing event.

### 3.6.8.6 Measurement and Verification

As utilities initiate demand management events, there is little feedback to measure the extent to which an event is successful. Customers may have participated in their demand management program, or they may not have participated due to an endless range of possibilities. This function in
the DRMS calculates baseline customer load profiles according to contractual terms and verifies reductions/changes in load from their profile for billing purposes. This information can be tied into a utility’s CIS to facilitate accurate billing and rewarding for participation in demand programs. The application also validates the probabilities of participation, expected load change, and anticipated rebound effect as estimated by the response estimator application.

### 3.7 ENERGY RESOURCE CHALLENGES

#### 3.7.1 DERs

Distribution systems were not designed to accommodate active generation and storage at the distribution level. Even though DERs can be connected anywhere on the distribution system (substation, primary feeder, low-voltage or secondary feeder, customer premises), their size and location have the most impact on the distribution system. Some factors to consider include bidirectional power flow, short-circuit current levels, system losses, reactive power flow, impact on lateral fusing, reverse power flow, islanding, and voltage and frequency control. The technologies and operational concepts to properly integrate DERs into the existing distribution feeders need to be addressed with smart grid solutions to avoid negative impacts on system reliability and safety.

There are several types of DER interconnection systems. They can be divided into two main groups:

- **Inverter-based systems**—These systems are used in batteries, fuel cells, PV, microturbine, and wind turbine applications. Some systems, such as batteries, fuel cells, and PV, generate DC power, and an inverter is required, which is a bidirectional DC/AC converter. Microturbines generate AC power with a high frequency that is typically converted to DC and then back to AC 50/60 Hz.
- Systems that run parallel to the distribution system and interconnection system that require synchronization with the common bus—These systems are typically used for load peak shaving, emergency power supply, and cogeneration.

Every DER system consists of the following major parts:

- **Prime mover**—This represents the primary source of power. There are several prime movers available today, such as reciprocating engines, microturbines, wind turbines, PV systems, fuel cells, and storage technologies.
- **Power converter**—This represents the way that power is converted from the prime mover to the electrical output of the DER. Synchronous generators, induction generators, double-fed asynchronous generators, inverters, and static power converters are examples of power converters.
- **Transformer, switches, relays, and communications devices**—These devices enable the connection and protection of the DER on the distribution system and vice versa.

Studies and operating experience indicate that it is easier to integrate PV solar and wind energy into a power system where other generators are available to provide balancing power, regulation, and precise load-following capabilities. The greater the number of intermittent renewable generation is operating in each area, the less their aggregate production is variable. Typical T&D system-related problems with high penetrations of DER [51] (greater than 20% of load) include the following.

#### 3.7.1.1 Standards

Most small- and large-scale distributed renewable generation resources are currently governed by the IEEE (Institute of Electrical and Electronics Engineers) 1547 [52] set of standards that include
references to UL1741 for interconnecting to low voltage networks. Some countries, like Australia and New Zealand, have their own set of standards, such as AS 4777. IEEE 1547 standards were developed toward the end of the 1990s when DG, especially distributed PV and wind generation, was at very low penetration levels. IEEE 1547 describes the interconnection issues of DG resources in terms of voltage limits, anti-islanding, power factor, and reactive power production mainly from a safety and utility operation point of view.

There are, however, concerns on some of the practical impacts of the IEEE 1547 standard on distribution feeder design, operation, and safety. These include reactive power injection, voltage regulation, low-voltage ride-through (LVRT), and power quality of high levels of inverters penetrating the distribution network without any coordinated control. Currently, there are several IEEE standard groups working on different application notes and setting the requirements for a future update on IEEE 1547. Larger wind generation facilities above 10 MW are now required to have LVRT capability to increase system reliability. New-generation interconnection requirements have been adopted by FERC as part of the FERC Order 661, docket RM05-4-0000 Notice Of Proposed Rulemaking (NOPR), mainly for large wind and solar power facilities, larger than 20 MW. These provisions are updated and adopted as Appendix G to the Large Generator Interconnection Agreement (LGIA) [53]. FERC also now requires renewable energy plants to be able to provide sufficient dynamic voltage support and reactive power if the utility’s system impact study shows that it is needed to maintain system reliability. This implies that wind generators should have dynamic reactive power capability for the entire power factor range.

Currently, there is also an industry-wide initiative on the Smart Grid Interoperability Panel [54]. This initiative is coordinated by NIST and EPRI. The main purpose of this panel is to develop interconnection and communications requirements for DERs, including PV, energy storage, and demand response. Some of the communication and protocol profiles for PV generation and storage systems include DNP3 (Distributed Network Protocol) and IEC 61850, but other standards are emerging, such as the Sunspec Alliance and Manufacturing Enterprises Solutions Association (MESA), for energy storage. The purpose of defining a standard communication profile is to make it easier to interconnect and operate DERs with increased security levels.

3.7.1.2 Intermittency and Dispatchability

PV and wind capacity factors (average output power as a ratio of maximum output power) typically range from 15% to 30%. Due to the fluctuating and uncontrollable nature of wind and PV power, their power generation must be balanced with other very fast controllable energy sources. These include gas, hydro, or renewable power-generating sources, as well as fast-acting energy storage, to smooth out fluctuating power from wind generators and increase the overall reliability and efficiency of the system. The costs associated with capital, operations, maintenance, and generator stop-start cycles must be considered.

In most urban regions, PV flat-plate collectors are predominately used for solar generation and can produce power production fluctuations with a sudden (seconds time scale) loss of complete power output. PV generation penetration within residential and commercial feeders is approaching 4–8 MW per feeder. During cloudy and foggy days, large power fluctuations are measured on the feeders with high penetration levels and can produce several problems—voltage quality, protection, uncoordinated reactive power demand, and power balancing [51]. Cloud cover and morning fog require fast ramping and fast power balancing. Furthermore, several other solar production facilities in close proximity on the same electrical distribution feeder can result in high levels of voltage fluctuations and even flicker on the feeder. Reactive power and voltage profile management on these feeders are common problems in areas where high penetration levels are experienced. Feeder automation and smart grid communications are, therefore, crucial to solve these intermittency problems.

IEEE Std. 1547 states that each DER unit or DER aggregate of 250 kVA or more shall have provisions for monitoring its connection status, real and reactive power output, and voltage at the point of DER connection. Monitoring the exchange of information and control for DER systems should
support interoperability between DER devices and the distribution system. Use of standard commands and protocols and data definitions enables this interoperability. In addition, this reduces costs for data translators, manual configuration, and special devices. DER can be dispatched as a unit for energy export as needed, according to a certain schedule, during peak periods, shut down for maintenance, used for ancillary services, such as load regulation, energy losses, spinning reserve, voltage regulation, and reactive power supply.

### 3.7.1.3 Voltage and Reactive Power

Electric distribution systems were designed for one-way power flow—from the substation downstream to the customers. In such systems, voltages are highest at the substation, and they are the lowest at the end of the line. However, this assumes that there are no distributed energy sources on the distribution system. Depending on the size of DERs and their placement on the feeder, it is possible to have the voltage at the end of the line to be higher than the voltage at the substation.

Reactive power management and coordination on feeders were not designed for high DER penetration levels. Due to PV and wind power variations and required ramp rates larger than 1 MW/s, fast-acting reactive power sources should be employed throughout the feeders and network. Reducing system losses represents one of the main challenges of a power utility today. Utilizing DERs reduces system losses if DERs are properly sized and placed. To obtain the maximum loss reduction in a radial distribution circuit with DERs, the DER must be placed at a position where the output current of DER is equal to half of the load demand. The reason for this is that the distance that power must travel from sources to loads is minimum, which, in turn, minimizes losses. However, if the DER is too large, then it will cause feeder losses to increase.

Voltage regulation in distribution power networks is specified in the ANSI C84.1 standard, where a nominal voltage of 120 V is the standard for a residential consumer supply, with allowable deviations of ±5%. The standard describes the process and equipment that is needed to keep the voltage within the limits. According to IEEE Std. 1547, “The DER shall not actively regulate voltage at the PCC (point of common coupling). The DER shall not cause the Area EPS (distribution system) service voltage at other local EPSs to go outside the requirements of ANSI C84.1 standards.”

DER significantly impacts voltage regulation and relay protection schemes. Voltage on MV (medium voltage) distribution networks is controlled by voltage regulators and capacitor banks, but LV (low voltage) feeders typically have no voltage control. The voltage drop depends on the wire size, type of conductor, length of the feeder, loads on the feeder, and power factor. DER can affect the voltage on distribution feeder in several ways. If DER power is injected into the distribution system, then it will reduce the amount of current needed from the substation for the load, thus automatically reducing the voltage drop. If DER supplies reactive power, the voltage drop will also be reduced. If DER absorbs reactive power, the voltage drop will increase. Most existing PV inverters do not provide reactive power and voltage support capability and do not have LVRT (low voltage ride-through) capability.

If there is a feeder with a voltage regulator that uses line drop compensation, and there is a large DER located downstream of the voltage regulator, it is possible that that the DER can supply most or all power to the load on the feeder, and it might also be capable of supplying the load upstream from it. If the voltage regulator cannot detect reverse power flow, then the voltage regulator assumes that the feeder is lightly loaded and will produce a voltage change that is opposite from what control algorithm expects. Voltage regulators should include a reactive bidirectional mode to operate correctly with DERs in reverse power flow scenarios.

Small-scale DER devices are mostly single phase. Injecting power will have an effect only on one phase, and the voltage difference can change between the phases, thus creating highly unbalanced phase voltages. This unbalance can exist even if the voltages are within ANSI C84.1 range. To alleviate this problem, the DER can be connected to the phase with the most load, and transferring single-phase load from the highest loaded phase to the other two phases. However, this brings additional cost to the utility to rebalance the load along the phases every time one or more consumers
connect a DER (e.g., install solar PV on the rooftop). In areas of the world where the LV distribution system serves 50–150 customers, voltage unbalance is becoming a significant problem.

DER devices (e.g., wind or solar) can be very unpredictable, and their output can be intermittent. The output of DERs can change rapidly, and this can cause voltage regulating devices to operate excessively. Most of these devices have a daily maximum limit in the number of operations. One solution is to change the time delay settings on voltage-regulating devices to provide better coordination with DER.

3.7.1.4 Protective Relaying

Short-circuit current levels on the distribution system vary greatly with respect to impedance of the feeder and length of the conductor. The addition of DER affects the levels of short-circuit currents, thus inadvertently affecting relay settings. One measure that is of interest is the ratio of the rated output current of DER with respect to the available short-circuit current at the POI (point of interconnection). For DERs on feeder primary voltage levels, if this ratio is ≥1%, then DER will have noticeable impact on voltage regulation, power quality, and voltage flicker. If the DER is on the secondary or low-voltage level of the feeder, a ratio of <1% can have major impact on secondary voltage.

The integration of DER may lead to reverse power flows through feeder sections and substations. The distribution grid, in general, has not been designed, built, and is not prepared for bidirectional power flows. It has been a long-standing practice of utilities to protect feeder lateral circuits with fuses. Utilities generally use two philosophies for protection coordination, fuse clearing and fuse saving, and in some case, a combination of both—fuse clearing where fault currents are high and fuse saving where fault currents are moderate to low. For the case of fuse saving, relays on substation breakers and upstream feeder reclosers trip before the fuse blows. The breaker must trip before the fuse starts to melt. Depending on the severity of the fault, these schemes sometimes cannot operate correctly. DER causes fuse saving schemes to be even more complex because of the increased fault currents. In addition, DER increases the fault current level through the fuse, but not necessarily through the substation breaker or feeder recloser. Furthermore, the addition of DER causes issues with fuse-to-fuse coordination. Choosing correct fuse sizes, relay settings, and DER tripping settings can alleviate this problem, but may not be optimal.

A critical component of protective devices on distribution networks is overcurrent relays. These relays have instantaneous and time-delayed settings, which cause the distribution breakers to trip if fault current levels have been exceeded. In addition, on 34.5-kV long distribution lines, sometimes distance relays that are overcurrent relay supervised are used because it might be hard to distinguish between the high-load currents and low-fault currents. The commonality between all these relays is that they are designed and built for one-way flow. However, reverse power flow can cause protection devices to misoperate. Additional impacts on protection systems are modification of the sensitivity of protective devices, such as circuit reclosers and relays due to the feeder load offset effect of DER, particularly for the case of large DER, and potential overvoltage issues during unintentional islanding conditions.

Smart grid technologies can play an important role in mitigating these impacts, for instance, by using adaptive protection systems, which allow the settings of protective devices to adapt to the varying system conditions, either feeder loading and configuration, or DER output. Most important is to recognize the need for distribution protection systems to evolve; this is expected to become more important as the penetration level of DERs and other smart grid technologies increases. As the complexity of operating the smart distribution system increases, the need for replacing conventional protective devices, specifically fuses, will also increase. It is likely that the distribution grid of the future will be similar to modern transmission systems, from a protection system standpoint.

3.7.1.5 DER Placement

Substations represent the strongest point of the distribution system. Placing DER in the substation represents less of a challenge for the distribution system since DER acts as another power source.
The only additional requirement is the modification of protection and control schemes that will account for the addition of DER. However, if capacity of the DER is greater than 15%–20% of the substation load, then additional issues arise, such as voltage regulation, equipment ratings, fault levels, and protective relaying. If capacity of the DER is close to the substation load, then issues will arise with voltage regulation on the transformer tap changer since the transformer tap changer will see a light loading and will not boost the voltage appropriately, thus causing the low voltage at the end of the line. If the capacity of DER is larger than substation load, then it will export power into the transmission system, thus creating additional protection and control issues.

The distribution system has a higher impedance on primary feeder lines, so DER placed anywhere on distribution lines will have more influence on the system than comparable DER placed in the substation. DER placed on the feeder can cause reverse power flows, and it requires additional protection and/or control equipment. Generally, security and safety of all protective devices may be compromised if DER causes fault levels to change by >5%.

3.7.1.6 Intentional and Unintentional Islanding

Islanding happens when part of the utility system has been isolated by operation of one or more protective devices, and DER that is installed in that isolated part of the system continues to supply power to the customers in that area. This is a very dangerous operating condition for several reasons:

- DER might not be able to maintain proper system parameters, such as voltage and frequency, and can damage customer equipment.
- The islanded area might be out of phase, so the utility system might not be able to reconnect the islanded area.
- There are safety issues with utility personnel working on downed lines that can be back-fed from DERs.
- Improper grounding can lead to high voltages during the islanding.

DERs that can self-excite are capable of islanding, while non-self-exciting DERs can island only if certain conditions have been met. There are two main techniques that are used to prevent islanding: frequency regulation and voltage regulation. During normal operation, frequency and voltage are fluctuating within certain ranges. For frequency, the settings are set to anywhere from 0.5 to 1.0 Hz from nominal frequency of 60 Hz. Allowed voltage variations are 120 ± 6 V at the customer meter. Thus, having frequency, undervoltage and overvoltage protection can prevent islanding.

An additional issue is reconnection of lines when attempting to clear faults. When a fault occurs on a feeder with DER, breakers trip, and depending on the reclosing sequence, they can reclose up to three times to attempt to clear the fault. IEEE Std. 1547 recommends DER to trip before any breaker reclosing occurs. After the DER trips off-line, for safety reasons, it is not advisable to have control logic programmed such that DER reconnects to the system immediately after the normal power supply has been established. DER should only be allowed to be reconnected after the voltage and frequency have returned to their normal limits. There are, however, some situations when the load on the island is balanced with the DER output. In that case, several techniques, such as voltage shift and frequency shift, are used to detect islanding. This protection should operate within a few seconds after islanding has occurred.

3.7.1.7 Frequency Control

Small-scale DER itself cannot control or change the system frequency. Large-scale (MW-size) DER, depending on the size and regulatory framework, may be allowed to provide ancillary services. Potentially, the wide-area controllability that can be achieved via smart grid technologies can allow the implementation of the “virtual power plant” concept, which consists of the aggregated and coordinated dispatch, and operation, of many DERs (either small-scale, medium-scale, or utility-scale), may allow this type of ancillary service. Similarly, the implementation of the microgrid concept...
requires the availability of DER with frequency control capability; This can be accomplished by means of distributed generation, the combination of intermittent distributed generation and storage, or using only distributed storage.

### 3.7.1.8 Power Quality

Fluctuations in PV and wind power production result in large-voltage fluctuations, as well as voltage flicker and other power quality issues. Potential impacts of DER integration are voltage rise, voltage fluctuation, flicker, voltage unbalance, voltage sags and swells, and increased total harmonic distortion (THD). In addition, when large numbers of small-scale DERs (e.g., rooftop solar PV) are connected to low-voltage feeders, they will change the voltage dynamics by increasing the voltage during low-load (e.g., in residential systems when occupants are away during the day) and high-generation conditions, since when a DER is supplying power to the grid, its inverter raises the voltage at the point of connection. This high voltage can lead to inverter (and DER) disconnect, as well as potential customer load damage. Furthermore, extreme PV intermittency due to cloud cover may lead to rapid voltage fluctuations; this has motivated some utilities to require the evaluation of potential flicker impacts as a requisite for authorizing DER connections. Voltage unbalance can be accentuated by large penetration levels of single-phase DER, particularly if different technologies and capacities are used, and if they are connected to different phases of the power distribution grid. Voltage sags and swells can be the consequence of fault current contributions and sudden connection and disconnection of utility-scale DG. Increased harmonic distortion may be caused by electronically coupled DERs; noting that even though individual inverters may comply with standard requirements pertaining to harmonic injection, it is the interaction and cumulative effect of harmonics produced by many inverters that could have a negative effect on feeder total harmonic levels. As previously indicated, smart grid technologies and intelligent control of DER inverters can help alleviate issues related to voltage rise, voltage fluctuation, and intermittency. Other issues, such as voltage sags and swells due to larger fault currents, may be mitigated using, for example, fast reacting fault current limiters. Issues related to increased voltage unbalance and harmonic distortion should be addressed in the planning stage of the smart grid, where maximum penetration levels and location of DER must be carefully evaluated. Another potential and more complex solution is the coordinated dispatch of these technologies via the virtual power plant concept.

### 3.7.1.9 Equipment Loading, Maintenance, and Life Cycle

In the same way that low-to-moderate penetration levels of DER (either conventional or intermittent) reduce equipment loading, moderate-to-high penetration levels or a condition that leads to reverse power flow may increase equipment loading up to a point where this can become a concern from an equipment rating perspective and lead to equipment overload. Similarly, the interaction among intermittent DER (PV and wind) and voltage control and regulation equipment, such as load tap changers (LTC), line voltage regulators, and voltage-controlled capacitor banks, may lead to frequent operation of this equipment (frequent tap changes and status changes). This, in turn, increases maintenance requirements, and, ultimately, if it is not properly addressed, it may impact equipment life cycles. The smart grid plays a key role in this regard with advanced monitoring, control and diagnostic capabilities. Energy storage and dynamic Volt/Var control and compensation using smart technologies, such as inverters and flexible AC distribution systems (FACDS), allow for the mitigation of potential voltage and power flow impacts due to intermittent DG.

### 3.7.2 Electric Vehicles

#### 3.7.2.1 Charging

PEVs (plug-in EVs—PHEV and BEV) have the potential to improve multiple facets of the transportation sector. However, for PEVs to have a significant positive impact on the transportation
sector, a substantial fraction of the vehicle fleet must be converted to PEVs. Any significant conversion of this type will impose a large demand on the electric sector if not properly administered. Therefore, to realize transportation improvements on a grand scale without creating concurrent electrical problems, changes in the electric and transportation sectors must be collaborative and occur concurrently.

The charging of PEVs is the most important interaction between electrified transportation and the electric grid, and is the area in which smart grid technologies can provide tools to integrate the two sectors. Plug-in vehicle charging is divided into two main categories: “smart” charging, and unconstrained charging. Unconstrained charging is the simplest form of plug-in vehicle charging and allows the vehicle owner to plug in at any time of the day without any limitations [55]. Constrained charging is defined as any charging strategy in which the electricity provider and vehicle can coordinate charging strategies to maximize the economic efficiency of vehicle charging. PEVs currently charge without control or restriction from the utility. Due to the current low volume of vehicles, this has a low impact on the electric grid [30,56]. However, most research to date has shown that as PEVs penetrate the market, unconstrained charging will need to be replaced with some level of constrained or “smart” charging to reduce the possibility of exacerbating peak electric demands [55,57]. Studies have shown that “smart” charging can potentially permit replacement of at least 50% of the traditional vehicle fleet with PEVs without the need to increase generation or grid capacity. Larger penetrations also present opportunities for the electric sector to regulate the system more effectively, resulting in more uniform daily load profiles, better capital utilization, and reduced operational costs [55,57].

The most prevalent strategies currently being pursued to implement smart charging are as follows:

- **Financial (TOU pricing, critical peak pricing, real-time pricing)—** Charging different rates at different times of the day to incentivize users to change their behavior
- **Direct (delayed charging, demand response)—** Curtailment of charging activities, enabled by smart charging chips or charger-side intelligence in a demand-response type program
- **Information based (home area network, smart meters, and displays)—** Giving users information and signals to help them make informed decisions about the cost and impact of charging on the grid [55,56,58,59]

Due to the variation in the energy sources used throughout the electric sector, some charging strategies may prove more advantageous and effective than others. All the “smart” charging strategies require some level of communication between the PEV, vehicle owner, and the electricity provider or grid system operator. For direct and financial smart-charging strategies, the plug-in vehicle or owner must be able to receive and process pricing and/or power control signals sent by the electricity provider [57]. More advanced charging strategies, especially market-oriented or two-way power flow strategies, require reliable, two-way communication between the plug-in vehicle and the electricity provider or the grid system operator [23,57]. Two-way communication is required because the electricity provider or grid system operator needs to know the state of charge (SOC) of all the PEVs connected to forecast the charging load for the valley-filling algorithm and the availability of PEVs to provide V2G (vehicle-to-grid) frequency control. Research has shown that the communication task can be achieved by integrating broadband over PowerLine and HomePlug, Zigbee, or cellular communications technologies into a stationary charger or into the PEV’s power electronics [59].

Regardless of the type of smart-charging strategy utilized, the required charging infrastructure and strategies will impose constraints on the electric grid. The largest impact smart charging will have on the electric grid is associated with the communications requirements needed between PEVs and owners, and the electricity provider or grid system operator. The simplest method (in terms of communication) for the electric sector to control charging behavior is to implement TOU rates. TOU rates can be relayed to PEV owners through rate plans that only change based on time of day
and year and require the installation of an electric meter capable of metering energy transfer in real time for billing purposes. However, it is yet to be determined if TOU rates are strong enough motivators to affect the charging habits of most plug-in vehicle owners. The next level of complexity available for the electric sector is the use of real-time data communication. Control could be based upon one-way communication: For example, vehicles could charge only when real-time rates drop below a set threshold. Several proposed control strategies (e.g., V2G) would also require two-way communication. However, for many PEVs, real-time data transfer is an overwhelming task [22].

The two most common automotive industry charging standards are the Society of Automotive Engineers (SAE) standard J1772 in the USA, and IEC 61851 in Europe and China. SAE J1772 defines three AC and DC charging levels (Table 3.7). Utility power is delivered as AC to the premise where the EVSE (Electric Vehicle Supply Equipment) is installed. The vehicle battery stores DC power, so the conversion from AC to DC is required to charge the battery. In AC charging, the AC to

<table>
<thead>
<tr>
<th>TABLE 3.7</th>
<th>SAE PHEV and BEV AC and DC Charging Ratings</th>
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<tbody>
<tr>
<td>Supply Voltage (V)</td>
<td>Maximum Charge Current (A)</td>
</tr>
<tr>
<td>AC Level 1</td>
<td>120, single-phase</td>
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<td></td>
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<td>AC Level 2</td>
<td>240, single-phase</td>
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<tr>
<td>AC Level 3 (to be determined)</td>
<td>Single-phase or three-phase</td>
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<tr>
<td>DC Level 1</td>
<td>200–500</td>
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<tr>
<td>DC Level 2</td>
<td>200–500</td>
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<tr>
<td>DC Level 3 (to be determined)</td>
<td>May cover 200–600</td>
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</table>

**Notes:** SAE International. “SAE Charging Configurations and Ratings Terminology,” ver. 100312, 2012, http://www.sae.org/smartgrid/chargingspeeds.pdf; BEV (25 kWh usable pack size) charging always starts at 20% SOC, and stops at 80% SOC instead of 100%; ideal charge times assume 90% efficient chargers, 150 W to 12 V loads, and no balancing of traction battery pack.

a PHEV can start from 0% SOC since hybrid mode is available.

SOC, state of charge = % of charge in the battery (0%–100%); EVSE, electric vehicle supply equipment.
DC conversion for the DC battery occurs in the vehicles onboard charger. In DC charging, the AC to DC conversion occurs in the EVSE off-board the vehicle. Currently, the most common is AC charging. Level 1 AC is when the charger is simply plugged into a 120-V wall socket, and it requires that the charger electronics be built into the car. Level 2 AC charging also assumes the electronics are in the car, but the charging source is single-phase AC at a nominal 240 V, with a maximum current capability of 32 A. Level 3 AC charging is still to be determined, but assumes that the vehicle charging electronics can handle either single-phase or three-phase AC via the charging port. Although various power levels of charging have been proposed, Level 1 charging (110 V, 15 A) is currently the most common. Level 2 and Level 3 rapid chargers have increased power ratings, but the installation of Level 2 and Level 3 chargers can be a slow and costly process, especially for residential installations [60,61]. The IEC 61851 used in Europe and China was derived from J1772 and has similar requirements, adapted for the European and Asian AC line voltages. Most terminology differences are superficial. Where the SAE standard describes “methods” and “levels,” the IEC standard talks about “modes,” which are virtually the same. For example, IEC 61851 Mode 1 relates to household charging from single-phase 250 V (maximum) or three-phase 480-V power connections, with a maximum current of 16 A. There are further unique requirements for grounding. IEC 61851 Mode 2 uses the same voltages as Mode 1, but doubles the maximum allowable current to 32. Mode 2 also adds a requirement for a “control pilot function,” and an integral ground-fault interrupter. IEC 61851 Mode 3 supports fast charging with currents up to 250A. Above that, as with J1772, it allows an external DC supply that may supply up to 400A.

Limitations on the size of household electrical services will impact the introduction of EVs—particularly, the selection of charging solutions. Many newer houses in the United States are equipped with 100A electrical services, while older homes may have smaller services, and larger homes may have 200A services or larger. Regardless of the absolute service size, in most cases, the installed service was properly sized for the anticipated loads in the household. Similarly, multiunit developments also size electrical services to meet electrical codes with limited spare capacity.

Although electrical codes remain relatively conservative, allowing for increased demand, introduction of a new, large electricity demand will likely violate those codes and possibly overload the electrical service. Furthermore, electrical codes do not generally allow the introduction of additional circuits based on the understanding that those circuits will not be utilized simultaneously with existing household loads. That is, although vehicle connections could be electronically limited to nighttime charging, when other household loads are low, there are currently few mechanisms in electrical codes to allow for such expansion.

The layout of household electrical services also presents issues. While newer homes frequently have the incoming electrical service in the garage area, in many older homes, the electrical service entrance is located far from the garage—a location that has traditionally experienced far lower loads than other parts of the house. The expense of modifying the incoming electrical panel and adding new circuits to the garage areas will likely slow the adoption of Level 2 and Level 3 charging. Vehicles charged at Level 1 will typically require continuous electrical connections all night to reach a full state-of-charge. Therefore, if only Level 1 charging is widely implemented, many of the most promising control mechanisms (controlled charging, V2G, etc.) offered by integrating EVs into the electrical grid will be inaccessible.

Clearly, some level of smart-charging infrastructure will be needed as PEVs begin to penetrate the transportation market. Smart grid technologies provide a variety of charging methods that can help ensure PEV customer satisfaction while maintaining a balance between plug-in vehicle charging demand and the electric grid’s resources. However, “smart” charging of PEVs will require a large investment in electric grid and communications infrastructure and will significantly increase the workload of the electric sector. For PEVs to be capable of V2G energy exchange, either an inverter must be added to the vehicle’s power electronics or equipment capable of utilizing the onboard charger as both an inverter and a rectifier would need to be used [58].
3.7.2.2 Voltage Regulation and Feeder Losses

The additional currents flowing through distribution transformers and lines due to moderate-to-high penetration scenarios of PEV may lead to an increase in voltage drop along distribution feeders that can cause low-voltage violations, particularly on areas located far from distribution substations. This issue can be addressed by installing additional line voltage regulators and switched capacitor banks, as well as by the coordinated dispatch and control of local DER, and the implementation of demand response and load control/management. PEV charging loads are expected to have a power factor close to unity; however, as the penetration level increases, higher charging loads imply higher currents and, therefore, increased distribution line and transformer losses. Therefore, PEV proliferation is expected to increase distribution system losses. Again, the combined implementation of conventional and smart grid solutions via the additional communications and control capabilities enabled by the smart grid is expected to be the more successful approach for ensuring adequate voltage regulation and minimizing the impact of PEVs on distribution losses. This also highlights the need for multiobjective optimization approaches for a coordinated utilization of all available resources.

3.7.2.3 Power Quality

As indicated in previous sections, increased harmonic distortion may be caused by large proliferation of inverter-based equipment, including PEV charging facilities; it is worth noting that despite the fact that individual inverters may comply with standard requirements pertaining to harmonic injection, it is the interaction and cumulative effect of harmonics produced by a large number of inverters (including PEV and electronically coupled DER inverters) that could have a negative effect on feeder harmonic levels. This is an area that requires attention and further research, since it is expected to become more important as the deployment of these technologies grows. As previously indicated, issues related to the increase of harmonics should be addressed in the planning stage of the smart grid, where maximum penetration levels and location of DERs and PEVs must be carefully evaluated.

3.7.2.4 Vehicle-to-Grid Energy Exchange

Almost since the first sales of hybrid vehicles, there has been considerable interest in using the vehicles as auxiliary power supplies—backup generators or supplemental power systems. In some geographical areas, there remains a substantial risk of power failure due to natural disasters, such as storms or floods. Owners of PEVs in these areas could tap into their vehicles’ electrical systems for backup power in the event of power failure. Several informal projects have utilized electric vehicles for this purpose, connecting directly to the traction battery [62] or operating solely off the vehicle’s 12-V convenience power [63].

These efforts have been hampered by the lack of support from vehicle manufacturers and the lack of suitable inverters capable of both connecting to the grid and supporting EV battery voltages. This application could rapidly become a de facto standard if many vehicles are equipped with inverters to support V2G operations, and if vehicle manufacturers see the backup power market as a potential added feature in their product offering. Serious safety issues must also be addressed, including electrical safety with both DC and AC circuits and the buildup of emissions if the vehicle is unintentionally operated in enclosed spaces.

It should be noted that vehicle manufacturers currently have little incentive to modify vehicles to support grid functions. Many proposed solutions, including V2G, controlled charging, and backup power applications, are likely to negatively impact battery life and/or decrease customer satisfaction—primary goals of the vehicle manufacturers. Ultimately, integration of PEVs into both the transportation and electricity sectors is a system problem, requiring system solutions. Viable solutions will need to balance competing goals of vehicle owners, grid operators, and vehicle manufacturers, as well as address issues as diverse as electrical code compliance and dispersed communication.
3.7.2.5 Equipment Loading, Maintenance, and Life Cycle

Arguably, the most significant impact of PEVs charging on the power grid is the increase in equipment loading, specifically on distribution transformers and lines. Here, it is worth noting that the severity of this impact is a function of the charging scenarios, charging strategy (uncontrolled or controlled charging), market penetration level, and distribution feeder characteristics (existing loading, voltage level, load profile, etc.). In order to determine the impact of PEV charging on the grid, it is necessary to conduct preliminary studies to determine (1) charging scenarios, like the one shown in Figure 3.22, which indicates the expected Level 1 and Level 2 charging profiles of PEVs (PHEVs and BEVs), that is, the time of day when charging is expected to occur and the likely charging demands in percentage of PEVs; and (2) market penetration levels, which indicate the amount of PEVs that are expected to be charged in a geographic area as a function of time. Studies and common sense indicate that residential PEV charging is expected to occur during the late afternoons and early evenings when commuters return home. Unfortunately, in many cases, this coincides with peak feeder loading conditions, which has a direct impact on increasing distribution transformer and line loadings.

The electric utility sector has expressed concern regarding expected increased loads on residential transformers and other electric grid components. Studies have shown that the growth of HEVs (such as the Toyota Prius) has typically occurred nonuniformly throughout geographic areas, with high concentrations in certain areas and little-to-no adoption in others. The adoption of PEVs is expected to follow a similar pattern [64].

Increased loading on residential transformers poses a problem for the electricity provider as most residential transformers are already approaching their load capacities. In addition, although “smart” charging of PEVs will help the electric sector reduce peak demands, “smart” charging may force transformers—especially residential transformers—to be fully utilized for the majority of the day. Increased use will reduce the amount of equipment rest and cooling time, which could shorten the operational life of the transformers and other electric grid equipment [65]. These studies agree, however, that these pressures will not result in significant decreases in reliability or functionality of distribution systems. They will merely require changes in distribution system maintenance schedules.

![Figure 3.22 Example of an expected PEV charging scenario (projected 2020).](image-url)
Once charging and market penetration scenarios are determined, it is necessary to conduct power flow analyses under a series of varying loading conditions to determine equipment loading. These simulations consist of superimposing PEV loads on expected customer or distribution transformer loads and running power flow analyses to determine feeder electrical variables (voltages, currents, etc.). The complexity of these analyses will vary depending on the accuracy sought, and they may include conducting statistical analyses to model the uncertainty about charging and market penetration scenarios. These analyses must be conducted for uncontrolled charging scenarios to determine “worst case” impacts, and under controlled charging scenarios that are designed to mitigate expected impacts. Controlled scenarios aim at modifying PEV charging profiles by providing incentives or penalties via TOU rates or exerting charging load control or management to displace charging to off-peak hours.

The literature indicates that under uncontrolled charging scenarios, transformer overloads are expected to occur even at low penetration levels (Figure 3.23). Even though, at first sight, smart grid technologies, such as controlled charging, appear to be a mitigation measure for equipment loading impacts, it has the disadvantage of shifting charging to off-peak hours, for example, during early morning. This ultimately leads to (1) increasing load coincidence and creating new peaks that may also overload distribution transformers and lines, especially for large market penetration levels (Figure 3.24) and (2) “flattening” distribution transformer load profiles, that is, increasing their load factors. Obviously, the former is undesired, and even though the latter seems attractive, it may have a negative impact on equipment maintenance and life cycle, since off-peak loading conditions allow distribution transformers to cool down. Therefore, incentives and load control or management strategies must be carefully designed and applied to avoid creating further impacts. Other solutions to equipment overload are conventional approaches, such as capacity increase (transformer upgrade, line reconductoring, etc.). Furthermore, the coordinated control and dispatch of local DER and the implementation of demand response are promising alternatives for solving these issues (Figure 3.25). Finally, a combination of all the approaches (conventional and smart grid technologies) is recommended. As indicated previously, the smart grid will play a critical role in enabling these solutions.

![Figure 3.23](image-url)  
**FIGURE 3.23** Example of percent of distribution system impacted versus PEV market penetration (uncontrolled charging). (From Dow, L. et al., A novel approach for evaluating the impact of electric vehicles on the power distribution system, 2010 IEEE PES General Meeting, Minneapolis, MN, July 2010. With permission.)
3.7.3 Consumer Demand

3.7.3.1 Changing Consumer Behavior

Different rates elicit different behaviors from consumers. Consumer behavior affects many aspects of utility’s operations, sometimes in very complex ways. Specifically, utilities are often concerned with one or more business performance metrics, such as the rate of return on capital investments, exposure to short-term wholesale price fluctuations, minimizing operating costs, controlling net revenue, or maximizing earnings. Consequently, utilities are challenged to not only design the different rates that elicit needed behaviors from customers, but they must also determine what fraction...
of their customers would ideally have to be on each rate to meet any of these business performance metrics.

One approach to this challenge lies with a method developed as part of the capital asset pricing model used in modern portfolio theory. The concept of an efficient frontier (dotted line) is illustrated in Figure 3.26, where the expectation of an outcome for a mixture of two rates is plotted against the uncertainty of that outcome [69].

The concept of the efficient frontier applies in this situation because a utility would try not to choose a mixture of rates that does not lie on the dotted line shown in Figure 3.26. Suppose a utility proposed to place all its customers on the RTP rate and none on the TOU rate. The expected earnings would be low, but the uncertainty would also be quite low. However, for the same uncertainty, the utility could realize significantly higher expected earnings by choosing a more balanced mixture of customers on each rate. Thus, for any outcome the utility wishes to maximize, only the mixtures of rates that lie on the top of the curve would be efficient, and all other mixtures would be suboptimal. Similarly, for any outcome the utility wishes to minimize, only mixtures that lie on the bottom of the curve would be efficient, and all other mixtures would be suboptimal. Typically, utilities have more than two rates that are being mixed, so the mixing regions between each of the rates may overlap as all combinations of mixtures are examined. However, the frontiers remain either the upper or lower boundaries of these regions.

In practice, utilities must collect data on consumer behavior in response to the rates. These data can be used to establish both outcomes for each business performance metric under each rate as well as the uncertainty of those outcomes in the face of uncertainty about costs and operating conditions. Therefore, utilities may wish to continuously update the analysis at least annually, perhaps more frequently, to determine the objective rate mixtures that the utility’s DR programs seek to achieve. The rate mixture objectives evolve over time in response to changing demographic conditions, the seasons, and perhaps even wholesale market conditions. The portfolio analysis method can be thought of as a long-term closed-loop control process that the utility uses to continuously optimize the performance of its DR systems.
A demand management event issued by the utility is successful if it can attract sufficient participation by end-use consumers resulting in the amount of demand reduction desired by the utility. Clearly, this creates a dynamic environment where the consumers and the utility interact through a system of incentives and agreements to achieve the target demand reduction. Large numbers of consumers, with their stochastic nature of energy consumption patterns, make it difficult to model the problem in a deterministic way. The behavior of consumers is affected by various market-driven factors, such as energy prices as well as personal habits and consumption patterns that vary from one individual to another.

When a store runs a sale advertisement, they learn over time their expected response rate from direct mail or other media. Customers do not tell them, “If you put this item on sale, I will come into your store and make a purchase.” However, the response rate from the sale ad is learned over time and can become very predictable. This ability to learn the response reliability over time based on data management experience is referred to as statistical reliability. Certain customer responses to smart grid stimuli will fall under this category of statistical reliability. Over time, the grid and utility operations will learn that when a specific signal is sent out, the response will be a predictable amount based on their historical learning. Statistical reliability is already applied in grid operations, utilizing inputs such as experience with the load curves, weather predictions, and utility experience to predict peak days and peak energy consumption. Learning to apply this concept to predict the response to demand management will save a considerable amount of cost and will enable inclusion of additional consumers and devices. This way, responses that cannot be measured via electronic means, or where the customer or device manufacturer does not support communications to the devices, can be included under this category of DR.

Throughout the years, most demand management applications have adopted solutions based on control and response models of aggregating individual consumers into groups of end users connected to a specific substation, feeder, or service transformer. This way, the volatility of the individual consumer behavior is reduced, and the problem can move further toward a probabilistic problem where the uncertainties can be treated as random variables. However, DR necessitates the introduction of a higher level of granularity where the stochastic models of individual customers are accounted for. On the one hand, these models should consider the behavioral and financial aspects of individual customers; on the other hand, they must incorporate the impact of the terms and conditions of the demand management programs into the decision-making by the consumers. Therefore, grid entities prefer an accurate indication of the current availability of the dynamically changing components of the demand management environment.

Identifying the behavioral patterns of consumers when it comes to electricity consumption is essential for ensuring sufficient participation following issuance of a demand management event. On the one hand, the event must be issued at times and locations when there is enough electricity consumption available; on the other hand, it must not contradict with individual consumer lifestyles, or at least need to be considered as acceptable (by consumers). In other words, there is a clear trade-off between achieving demand reduction and consumer inconvenience. From the utility perspective, an accurate model/prediction of consumer behavior and consumption patterns is critical to a successful demand management program. From the consumer perspective, there must be the ability to opt out of any program or specific instance that conflicts with a consumer lifestyle or specific schedule. Consumer device manufacturers, concerned about the satisfaction of their customers, require the opt-out feature before allowing their products to participate in demand management automation. This will tend to induce an element of variability into consumer demand management programs. In a general sense, the demand pattern of consumers can be analyzed and estimated from two aspects.

**Consumption habits:** This is related, in part, to the individual habits of using various household electric appliances, for instance, washer/dryer, dishwasher, etc. The number of times a week/day that each appliance is used and the duration of each usage are likely to reflect a specific pattern for each consumer. This portion of demand reduction is what qualifies for demand dispatch, where
the utility tries to shift the consumption from peak-load to off-peak hours. This can be done either manually by proposing time frames for usage of the various appliances or automatically by remote activation/deactivation of appliances according to utility needs and customer acceptance parameters. A currently less common source of demand reduction, which is likely to grow, is associated with charging electric vehicles. This is perhaps one example where most consumers are very flexible as to what time of the day the charging phase should take place (as long as it is done automatically). Another major portion of demand reduction is related to the temperature settings of heating and air conditioner units in winter and summer seasons, where consumers show different levels of sensitivity to heat/cold and show various degrees of flexibility to deviations from their habitual comfort zone because of demand management. This flexibility is complex since the settings may lead to different comfort perceptions according to the specific environment on each day, such as the difference between the outside and inside temperatures, as well as cumulative effects (e.g., how many consecutive days of hot weather).

**Elasticity to electricity prices:** A rather crucial assumption behind DR assumes that consumers are willing to temporarily forgo their convenience to avoid higher electricity prices or to capture incentives. While this is perhaps true for a sizeable portion of the consumers, the degree to which they are willing to give up their comfort level (and what the perception of comfort really entails) varies from one individual to another and may be impacted by the financial incentives offered. The consumer sensitivity to the electricity prices is utilized by the utility by introducing real-time pricing tailored toward peak-hour needs.

Incentives offered to consumers to encourage them to participate in a demand management event play an important role in its success. For demand dispatch applications at the residential level, to shift certain loads from peak to off-peak hours, the value of the incentives is not extremely critical, especially if the shifting is done automatically and may not even be detected by the consumer. Examples of this are electric vehicle charging and water heating. However, for other residential applications, for instance, air conditioning usage, where the comfort level of the consumers is affected most immediately, the role of the incentive payments is higher. For commercial buildings, air conditioning usage can be shifted—rather than curtailed—by preheating/ precooling the building during off-peak hours, for example, early in the morning before arrival of the occupants, and turning off the air conditioning unit during peak-load hours. Such practice becomes more difficult in the residential market where consumer lifestyles and schedules are more dynamic in nature. The financial incentives a utility can offer have limitations dictated by the financial calculations by the utility relative to their cost structure and level of vertical integration.

### 3.7.3.2 Delivery of Real-Time Information

To look at an electric load as a resource, there must be an architecture-enabling management of the load. As the wholesale price of electricity fluctuates, there is a desire to be able to reflect this fluctuation in the retail electric rates. Most people have become accustomed to watching the cost of fuel for their car. Their buying decision may be accelerated or delayed in accordance with the price. In a similar way, the price of electricity can impact consumer purchases of the electricity product. In the past, there was no mechanism to inform the consumer of the current price of the electricity product. But when the price of these products starts to change rapidly, the price became a key piece of information the consumer needs to know prior to the purchase, or in the case of electricity, consumption of the product.

With the trend toward a variety of time-based pricing rates, electric customers need access to the price information they have not had to deal with before. Compared with auto fuel, the consumption of electric power has additional layers of complexity. One could easily determine the miles-per-gallon (MPG) in a vehicle. But in my home, it is like having multiple vehicles with a very wide range of MPG ratings. Furthermore, these “vehicles” may operate concurrently or in any combination. Some of them operate without our knowledge and without a reasonable method to control their utilization. For example, consumers do not know exactly when their refrigerator will operate. Other than
unplugging it completely, there is little control over its operation. To motivate a change in electricity use, customers will need more information prior to purchase.

Unlike other commodities purchased as consumers, the electric information has several caveats to address. Getting the information to the customer via an adequate mechanism may also have a dependency on how often they need to have the information updated. Can the price change every month, week, day, and hour or even in a shorter block of time? How much notice of the price is needed? As noted in the MPG discussion, price is not enough information for a consumer to manage consumption in an environment where usage is not known. The customer needs to know the quantity they expect to consume.

This leads to the two core requirements for smart display of information: price and consumption. Consumers can also benefit from additional information, such as when the price will change again and whether it will be expensive in the future. Knowing how much electricity will need to be purchased must also be known to make good financial decisions.

It is also necessary to communicate information customers have not previously had to understand. A kilowatt-hour is not a term in the average daily vocabulary nor is its meaning. Some manipulation of the data is required before it is presented to the customer. Several types of display devices have been designed to do this. The first devices for demand management applications were mostly independent In-Home Displays (IHDs) that, using their own sensors or meter access methods, could be located or mounted according to consumer preferences. The IHDs generally displayed the key pieces of information to answer the questions: How much has my electricity cost me this month (or during some selectable period)? At what rate am I purchasing electricity now? An IHD may indicate the current electricity price, the rate at which it is being used, and the cost per hour. For example, the display may indicate that at the current rate of energy consumption, the cost is $0.37 per hour. The display could show additional computations for the consumer. These could include the projected cost of the current month at the current rate of energy consumption, a comparison with last month, a graph of usage by day or month, or any of several other potential calculations depending on the amount of energy usage history the device is able to store.

In the 2009–2010 time frame, NIST (National Institute of Standards and Technology) in the United States was approaching a task handed to them via legislation. Recognizing the need to make this type of information available, a priority action plan was initiated to help create a standard method to communicate electric consumption and usage information in a standard format. With the introduction of these standards, a variety of methods of reporting this information to the consumer was enabled, and the open market could look at the best way to relay the information to the consumer. The standards also led to the introduction of the “Green Button,” which utilizes this usage information to display energy consumption to consumers in new creative ways via a variety of personal devices that include dedicated devices in the home, the Internet, and personal smartphones.

The smart meter is one device that can be enabled with communications technology to provide consumption information to the consumer. The newer communicating electric meters, often referred to as the “smart meter,” are designed to calculate consumption at programmed intervals. To provide this information to the customer, several methods are available. One is to design communication electronics in the meter that will transmit this information into the home/premise. Another method is where the utility uses the Internet to forward real-time data back to the home/premise.

An advantage of routing the real-time consumption through the Internet is that it would enable a third-party firm to contractually agree with the utility and consumer to have access to the data. This third party could provide the service of displaying the data in a very advanced graphical format that is accessible via a number of devices including the computer, Internet, PDA, phone, TV, text message, and any other available means. These third-party service providers could also provide

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12 Based on UCAIug OpenADE and NAESB PAP10 standards ratified in October 2011.
technology to assist the consumer in managing the energy inside the premise. A disadvantage is the
dependency on other nonutility and nonconsumer-owned systems and devices that may exist in the
communication and control path. There may also be more concerns with data security and privacy
when the data pass through more systems.

One advantage of having a smart meter capable of transmitting the data directly to devices inside
a premise is that the route is more direct. The information may be available sooner and more reliably
due to fewer points in the pathway. Privacy concerns are easier to manage since the data do not pass
through third-party systems.

3.7.3.3 Delivery of Advanced Information
In cases like the use of behavioral demand response in incentive programs, where the customer is
compensated for the curtailment they can achieve, results can be achieved by informing customers
before the upcoming event, giving them advice on how they can maximize their energy reductions,
perhaps also include information on incentives, and performance from previous events. Customers
will then act without the need for any real-time information or technology interfacing to their loads
or any other energy device in the home.

3.7.3.4 Smart Loads and Appliances
Past approaches to controlling large residential loads have included ways to limit electric use in water
heating, pool pumps, and air conditioners. The basic approach is to control a switch to turn on or off
the load remotely. For certain loads, such as the water heater or pool pump, this can be done typically
without consumer objection or knowledge of when activation has occurred. The cost of adding this
type of switch required on-site installation at a total cost nearing the cost of the device being con-
trolled. Manufacturers are starting to include this switching ability in core product lines that makes
the addition of this type of control possible at a small fraction of the cost of after-market methods.
These advances will likely pave the way to a simple consumer installable add-on that is also utility
trackable and verifiable. For control of air conditioning, several approaches have been tested. These
have included control of the compressor itself in some pilots. Another approach is to wire the control
between the thermostat and the AC unit to effectively mimic the thermostat control without having
to enter the premise for installation. Other more sophisticated approaches involve smart thermostats
able to receive demand management messages that provide both control and the interface to the con-
sumer. The thermostat messages from the smart grid could include messages used for other methods
of impacting consumption.

In addition to the energy display mechanisms, the same data can be utilized anywhere the
capability exists to receive the information and relay it to a customer. As other in-premise devices
advance, they continue to have better hardware to communicate with the consumer, and additional
places become available for the display of energy information. One distinct advantage of this
display advancement is that the consumer could use the display to decide when to operate an appli-
cance, such as an oven, dishwasher, or washing machine. This provides an opportunity to impact
the use at the decision-making time for these process-oriented devices (e.g., cooking and cleaning)
that interact directly with the consumer. In addition to optionally displaying energy information,
a device can respond by changing or limiting energy consumption in an automated manner with
full knowledge of the best way to limit, delay, or optimize performance over a specified period.
In considering this capability, information can be transmitted into a home or premise for impact-
ing energy consumption in parallel with an informational display and ability to manage consumer
preferences.

Devices that can receive communicated energy information and respond by altering energy con-
sumption are often referred to as “smart devices” or “smart appliances.” For example, a drying
appliance could reduce the amount of heat applied and lengthen the drying cycle. A product utiliz-
ing refrigeration may have a variable-speed component able to scale back the use of electricity in
an acceptable way over a temporary period without turning off the device. The microprocessor controlling the device, based on detailed internal knowledge, can determine what it can do and for how long while maintaining safety and success of the process being controlled.

By automating the process of demand reduction/curtailment, smart appliances can help smooth the execution of DR events with minimum effort from the consumer. The key to designing smart appliances is to reduce the amount of consumer interaction needed in decision-making by putting energy management and interface logic into the device controls. The appliance can perform necessary actions to both meet the utility needs as well as accommodate the customer’s preferences. These preset rules and conditions, updated by the consumer according to individual needs and preferences, remove the burden of decision-making from consumers. A demand management event issued by the utility is followed to the variable extent that matches requirements and options set forth by the consumer. The actions taken afterward, turning off a device, reducing the load, shifting the load to a different time, or ignoring the request, can then be implemented automatically. The smart appliances already have an interface with the consumer and are well qualified to present the energy configuration options to the consumer for their selection. For simple devices, such as water heaters, thermostats, or even remote switches, the device may be turned on/off entirely. In more complicated designs or appliances that have specific modes of operation, there can be intelligent controls or responses to intelligent controllers that react in accordance with the price of energy or demand management events issued, and considering the preferences of the local consumer, while complying with optimal operation as defined by the manufacturer.

3.7.3.5 Consumer Energy Management

As smarter load controls evolve with communications technology, it is possible to integrate and manage the control of loads to more effectively respond to DR signals. The smart loads exchange data over a local communications network (wired or wireless) in the home or consumer premise, commonly known as a HAN.

Such devices that integrate and manage the control of consumer loads are commonly referred to as HEMs. A HEM can determine the operating status of all loads and optimize the control and scheduling of loads based on consumer preferences along with demand and price signals from the utility or grid. More advanced HEMs will include the capability to manage consumer renewable generation and even electric vehicles to provide estimation and historical data to help consumers make more informed decisions about managing their energy usage. These HEM functionalities are also provided by apps that are usable on smartphones, making consumer accessibility to these permanent and providing remote control of the connected appliances.

3.7.3.6 Consumer Education and Participation

Successful smart grid implementation requires educating consumers on the benefits of the technologies and enlightening them on the easiest ways to enjoy the benefits without having to change their lifestyle, thereby ensuring consumers are voluntarily engaging in the programs offered by their respective utility. For a demand management program to be effective, the consumer benefits must be clearly understood and sought by the consumer. The value of the smart grid investment increases significantly as consumer participation increases, and in the long run, increased participation could drive down the cost of electricity for everybody.

It will be important for customers to understand how the cost of the DRM program will be recovered, especially if it is tied to a smart meter deployment, and ensure that customers do not associate implementation of smart meters and smart grid with increased personal energy costs. Additionally, through effective education, consumers will “opt-in” to utility programs and continue to be engaged about how much they are saving—both themselves and the environment.
Customer education is key to the success of DR. Without proper information, consumers might consider DR as an action that leads to inconvenience and a disruption of their lifestyle. This means the utility will have to be close to the customer and adapt to customer-changing preferences and provide innovative products that keep the customer positively engaged. Customers also need help to determine their most effective course of action in impacting their energy consumption and cost [70]. The incentive payments for subscribing to DR—specifically for the residential customers—might not be high enough to provide financial justification by itself. Clearly, DR can lead to beneficial short-term impacts on the electricity market that increase as the number of customers participating in the demand management program increases. However, more efficient results could be achieved by focusing on the benefits to individual customers. These include

- Individual financial savings: In addition to receiving incentive payments and discounted rates, a customer participating in a demand management event, for example, by shifting the noncritical portion of demand from peak-load hours to off-peak hours, could also benefit from savings in monthly electricity bills.
- Besides personal costs savings, consumers have a growing concern about the environment [70]. Consumer engagement may be increased by making sure they understand the environmental benefits of their proposed response to grid conditions.
- Avoiding uncontrolled loss of service: By participating in a demand management event, for instance, through direct load control program for air conditioning units, a customer can help the utility achieve a controlled load reduction where power will be restored after the preset duration of the event is passed. Lack of sufficient participation, in the long run, could lead to weakening of the distribution network during peak-load hours, which, in turn, could lead to an uncontrolled loss of supply.

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