U.S. DEPARTMENT OF ENERGY

Maintaining Reliability in the Modern Power System

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ENERGY

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EXECUTIVE SUMMARY

The electric sector is undergoing a time of transition. Inexpensive natural gas, lower cost renewable power and increased use of energy efficiency and distributed generation are leading to a transformation in the way power is produced and delivered to consumers. As a consequence, many of the old paradigms that govern the sector are also evolving, importantly the traditional model of large centralized generators as a means of producing electricity and maintaining reliability. As more of these generators have retired in recent years and been replaced with new sources of power and energy efficiency, there have been questions about how to sustain the current level of reliability. This paper discusses the tools that the power sector will use to maintain reliability through this time of transformation.

While there are numerous standards and regulations that govern reliability of the power sector, this paper consolidates them into four "rules":

1. Power generation and transmission capacity must be sufficient to meet peak demand for electricity
2. Power systems must have adequate flexibility to address variability and uncertainty in demand (load) and generation resources
3. Power systems must be able to maintain steady frequency
4. Power systems must be able to maintain voltage within an acceptable range

For each rule, we discuss how it has been met historically and the new technologies and practices that will let it be met during and after this time of power sector transformation. The conclusion is that, while reliability has been historically maintained by a limited set of tools, primarily large spinning generators, there is now a new toolbox for maintaining reliability. With this new toolbox and continued careful planning, coordination and investment, reliability can remain a trademark characteristic of our evolving power system.

POWER GENERATION AND TRANSMISSION CAPACITY MUST BE SUFFICIENT TO MEET PEAK DEMAND FOR ELECTRICITY

The power grid must have sufficient capacity available to meet the demand for electricity. Because there are uncertainties in forecasting demand and the potential for generation and transmission outages, the total amount of capacity is required to exceed the expected level of demand by a given fraction, termed the reserve margin, often about 15%.

TRADITIONAL MEANS: Large conventional generators have traditionally provided the capacity to meet peak demand and reserve margins, and high voltage transmission lines have provided the means to move the power to where it is needed. In recent years, resources that lower demand for electricity have also begun to play a significant role.

NEW OPTIONS: While one cannot know far in advance the output of any variable resource such as wind and solar, these resources can still play a role in meeting peak demand by taking into account the probabilistic aspects of their generation profile. Aggregation of these resources can reduce their overall variability. Demand response and smart grid technologies can be used to reduce peak load. Lastly, storage can be used to meet peak load by saving power (or thermal energy) from when it is cheaper to generate and using it when it is most valuable.

POWER SYSTEMS MUST HAVE ADEQUATE FLEXIBILITY TO ADDRESS VARIABILITY AND UNCERTAINTY IN DEMAND (LOAD) AND GENERATION RESOURCES

The level of demand changes throughout the day and from season to season. This, and the addition of variable generation such as wind and solar, places a premium on having flexible generation capacity that can change its level of output to account for changes in demand and the amount of generation from variable resources (such as when the wind stops blowing or the sun goes down).

TRADITIONAL MEANS: Traditionally, the need for flexible generation has been met with natural gas generators, which are capable of ramping their output up and down rapidly. Demand response has also played a growing role. Recent analyses indicate that the current level of flexibility on the grid can accommodate variable generation levels of up to 35% of all generation.

NEW OPTIONS: Many grid operators are planning to or are already implementing policies to increase the flexibility of their systems. New, modern gas generators have been designed to provide very fast ramp rates. Expanded use of demand response also provides more flexibility. Lastly, it is possible to add technology to allow variable resources to decrease generation and, potentially, to increase it if they are not using all available power. This ability to dispatch variable generation is already being used to provide flexibility across the country.

POWER SYSTEMS MUST BE ABLE TO MAINTAIN STEADY FREQUENCY

The power system uses what is called alternating current (AC) where the electricity reverses direction sixty times per second (60 Hz). If this frequency of oscillation were to deviate significantly from 60 Hz, it could damage machines and electronics. Any mismatch between the supply and demand of electricity can cause this sort of deviation, and a number of mechanisms operating at different timescales are used to maintain a steady frequency.

TRADITIONAL MEANS: Large spinning generators are used to arrest any change in frequency because it takes time for them to change their rate of rotation. Generators can have governors that detect any change in their rate of rotation and increase or decrease power to compensate. On longer timescales, generation that can rapidly respond is kept in reserve to match supply and demand.

NEW OPTIONS: Studies have shown that increased levels of variable generation on the grid increase reserve requirements necessary to maintain a steady frequency, but these increases are quite modest. Transmission can be used to average out some of the variability and reduce the need for additional reserves. Even as they retire, large spinning generators can be used as "synchronous condensers" that spin synchronously with the grid, not consuming fuel, but serving to arrest changes in frequency. In addition, it is possible to make a variable resource act like a large spinning generator through the use of advanced power electronics. Demand response and storage to balance supply and demand also will likely play a growing role in maintaining a steady frequency.

POWER SYSTEMS MUST BE ABLE TO MAINTAIN VOLTAGE WITHIN AN ACCEPTABLE RANGE

In addition to maintaining a steady frequency, the electric grid must also deliver electricity at a given voltage. This voltage varies throughout the power grid with transformers used to change voltages. Maintaining the correct voltage requires the management of "reactive power" which is a property of AC electricity that allows power to flow. If the levels of reactive power are too high or are too low, the voltage level can change, potentially even collapsing catastrophically.

TRADITIONAL MEANS: Large spinning generators that are synchronized with the grid can control voltage levels and reactive power by adjusting their output. Various electrical devices such as shunt capacitors are used to control reactive power throughout the transmission and distribution networks.

NEW OPTIONS: As with frequency control, advanced power electronics can give variable generation resources like wind and solar the ability to control reactive power and voltage. FERC has recently issued an order requiring this capability on larger variable generation units. Many types of storage can also use this sort of power electronics. In addition, synchronous condensers can be used to provide reactive power. Lastly, there is a class of relative inexpensive electronic devices called Flexible AC Transmission Systems (FACTS) that have existed for a while but are becoming less expensive and more widely deployed and can solve many voltage control problems that historically would have required larger and more costly generators, transmission lines or electromechanical devices.

INTRODUCTION

In the United States, we enjoy the benefits of a highly reliable electrical power system. Reliable, affordable electric power fuels the economy and supports our quality of life. Each time we turn on a light, plug in a phone, approach a traffic signal, or log onto a computer, we trust that the power system will be working to enable the services we expect. That is power system reliability: the ability of the system to deliver expected service through both planned and unplanned events.

Catastrophic events such as hurricanes and earthquakes can disrupt U.S. power service, but day-to-day interruptions are rare. Typically, power system failures result in interruption in customer service for less than 3 hours of the 8,760 hours in a year.[1] Furthermore, most of these failures affect relatively few customers and occur on the distribution system—the network of local lower-voltage power lines that transfer electricity from the high-voltage bulk power system to our homes and businesses. Power outages due to failures of the bulk power transmission system are far less common. This is due, in large part, to how such power systems are built and operated so that safeguards keep the systems running even when any individual component fails.

The high level of reliability provided by the U.S. grid is not by accident.[2] The U.S. Department of Energy, Federal Energy Regulatory Commission (FERC), North American Electric Reliability Corporation (NERC), regional planning authorities, utilities, power system operators, and other organizations work to ensure adequate reliability of the U.S. power system through implementation of reliability standards, timely planning and investment, and effective system operations and coordination.

During most of the 20th century, electric utilities adhered to industry and self-imposed reliability criteria for electricity generation and transmission as they built and operated large hydroelectric, nuclear, and fossil-fueled power plants. These power plants, regionally connected with high-voltage power lines, now form the foundation of reliable, affordable electricity systems throughout the United States and internationally.

Recently, however, a combination of market forces and emerging trends are transforming the ways we generate and deliver electricity. Key drivers include comparatively low-cost natural gas, the increase in deployment of renewable energy technologies, environmental policies, consumer preferences, low demand growth, and the creation and continued evolution of restructured electricity markets. In many cases, the traditional model of large centralized generators is evolving as retiring generators are replaced with variable wind and solar generators, smaller and more flexible natural gas generators, and non-traditional resources such as demand-response (DR) and distributed generation. In the midst of

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[1] This is the national average. There is a very large variation by state. In 2013, the range was 7 minutes on average in Vermont to more than 18 hours in South Dakota. See Wirfs-Brock, J. 2015. "How Long is Your Blackout?" *Inside Energy*. Accessed March 2016, http://insideenergy.org/2015/03/20/ie-questions-how-long-is-your-blackout/

[2] For additional discussion of the concept of power system reliability see http://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf.

these changes, a variety of new technologies and practices have arisen to help maintain electric system reliability. In this paper, we examine how power system operators are using these new technologies and practices to maintain a high level of grid reliability.

There is an extensive set of standards and regulations that utilities and system operators must meet to maintain a reliable grid. For this report, we consolidate these into four overarching “rules”[3] for power system reliability:

1. Power generation and transmission capacity must be sufficient to meet peak demand for electricity
2. Power systems must have adequate flexibility to address variability and uncertainty in demand (load) and generation resources
3. Power systems must be able to maintain steady frequency
4. Power systems must be able to maintain voltage within an acceptable range

In the remainder of this paper, we will discuss each of these rules, how they have been met historically and how modern energy system practices and technologies—including variable renewable generation like wind and solar power and “smart grid” technologies—give power system operators new tools and methods for ensuring power system reliability.

[3] These “rules” are not directly formalized in any single regulation. Instead, they represent a summary of the numerous regulations and practices that grid operators follow to maintain reliability.

FOLLOWING THE FOUR RULES: PAST, PRESENT, AND FUTURE

RULE 1: POWER GENERATION AND TRANSMISSION CAPACITY MUST BE SUFFICIENT TO MEET PEAK DEMAND FOR ELECTRICITY.

WHY PEAK DEMAND MATTERS

The demand for electricity varies over short and long timescales. Typically, electricity demand is higher during the day and during warmer summer months, which aligns with greatest use of air conditioning. The demand for electricity on a hot summer afternoon can be more than twice the demand during spring evenings. This pattern of demand is similar across most of the United States, although some northern states experience peak demand during winter. Figure 1 illustrates the hourly demand for three different one-week periods in four regions of the country. The power system must be able to effectively deliver energy during these peak demand periods, or there would partial black-outs. Having sufficient resources available on the system to be able to meet peak demand is called "resource adequacy".

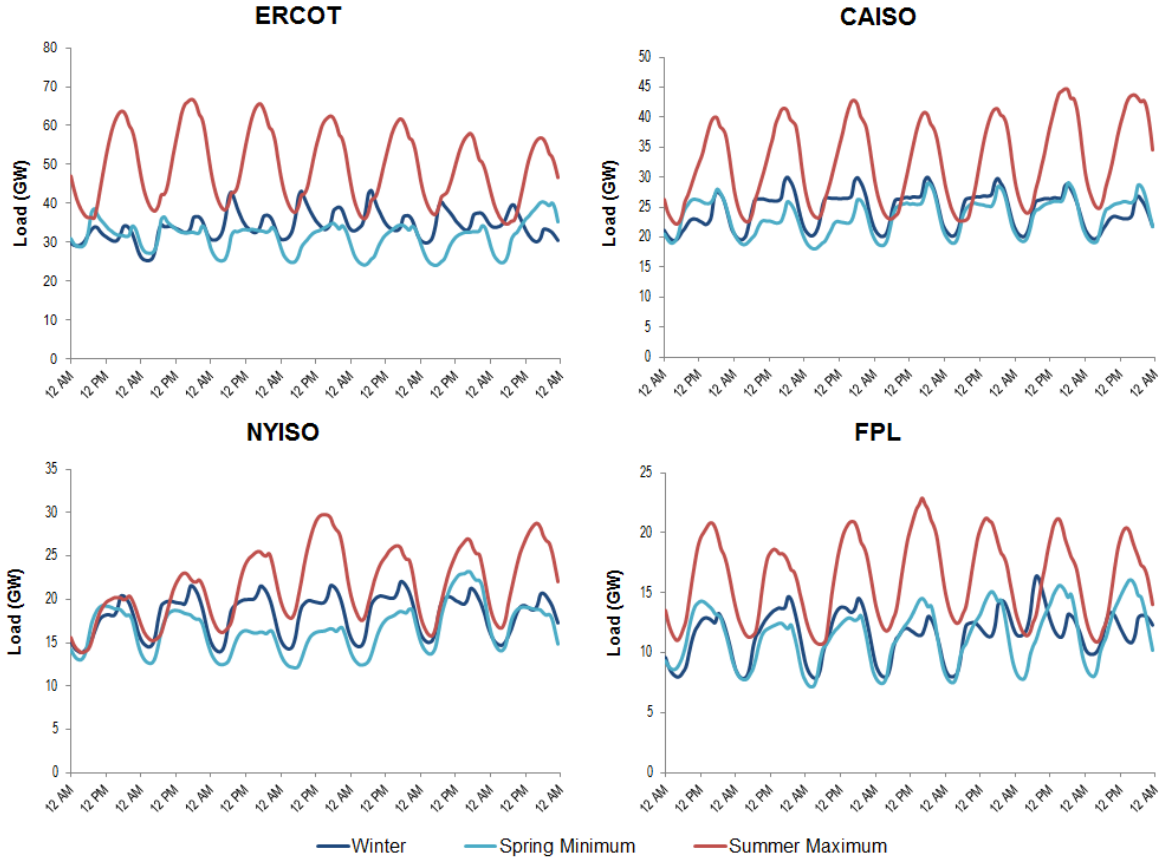

Figure 1. Historic hourly load patterns for ERCOT (Texas), CAISO (California), NYISO (New York) and Florida Power and Light for significant weeks in 2014.

System planners estimate the total peak demand for electricity for several years into the future to account for expected load growth. This process is called "load forecasting." Planners then determine if or how much additional capacity will be needed to meet forecast demand. These calculations typically account for existing capacity, anticipated plant retirements and a host of federal and state regulatory issues ranging from emissions regulations to renewable portfolio standards. In some cases, retired generators are not replaced at all, which removes some capacity from the power system. There is some degree of regional variation in the methods that planners use to calculate the amount of capacity required to meet peak load, but all planners must develop an estimate of the required capacity. Forecasting and advance planning help ensure that utilities and developers have adequate lead time to bring new generators and supporting infrastructure online, as the approval, permitting and construction process can take several years.

Two key steps are important when determining the total generation capacity requirement: 1) establish a target resource adequacy level (often measured by loss of load expectation as discussed later in this section), and 2) estimate the amount of generation needed to meet that resource adequacy level (often measured by the planning reserve margin). These steps are repeated (typically at least once a year) to ensure that the system is able to respond to load growth and other factors affecting system reliability. The planning reserve margin is the quantity of "spare" or "backup" capacity that the utility or grid operator holds in reserve that can be used to respond to a range of factors that could threaten the ability to meet load. These factors include:

1. Errors in forecasting: Load can be higher than anticipated, as is the case when unusually hot summer weather creates a spike in air conditioning demand.

2. Forced (unplanned) outages: No power plant is 100% reliable, and since generators can fail, it is necessary to have spare capacity available to provide backup.

3. Transmission outages: Transmission lines and associated equipment can also fail, which limits the amount of electricity that can be delivered from generators to load.

The planning reserve margin is measured by the total amount of capacity available (typically measured in MW) above the expected peak demand. For example, a system with an anticipated peak demand of 10,000 MW might maintain a planning reserve margin of 15%, or a total of 11,500 MW of conventional capacity. The 1,500 MW of "spare" capacity is then available to maintain system reliability. In setting the planning reserve margin target, utilities, system operators or regulators often rely on detailed reliability calculations to determine how much capacity is needed to ensure that blackouts rarely occur. For example, a utility may set a planning reserve margin based on a loss-of-load expectation target of 0.1 days/year or 0.1 events/year.[4] Once the target planning reserve margin is set and the total amount of

[4] For a comprehensive discussion, see Pfeifenberger et al. (2013), who note, "Although the 1-in-10 standard is widely used across North America, substantial variations in how it is implemented mean that it does not represent a uniform level of reliability…. the 1-in-10 standard may be interpreted as either one event in ten years or one day in ten years. One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. One day in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages."

capacity needed is estimated, utilities or project developers determine what type of resources to build to provide that capacity.

COMPLYING WITH RULE 1: TRADITIONAL MEANS

Traditionally, system operators rely on generators to provide the capacity to meet planning reserve margins. However, building adequate conventional capacity is not the only tool for maintaining resource adequacy. Energy Efficiency (EE) and Demand Response (DR) have been used by utilities to reduce peak demand. By lowering peak demand, these options can often act as a direct substitution for conventional capacity for meeting planning reserve margins and maintaining system reliability. In addition, the construction of new transmission lines to enable access to power from neighboring resources has also been used as a traditional means of meeting reserve margins.

CONVENTIONAL POWER PLANTS

Before the large-scale penetration of variable generation (VG) resources, power plants were often categorized by the type of load they commonly provided: baseload, intermediate or peaking. Generally, different types of plants are used to meet each type of load. Baseload plants, which are typically lower-cost nuclear or coal plants, are used to meet the constant demand on the system. Although the output levels of these plants can be altered, it is usually most economical for them to run at close-to-full capacity at all times. Intermediate load plants, often gas-fired, including combined-cycle plants, are used to meet the daily variations in demand. More recently, low gas prices are prompting the use of natural gas combined-cycle (NGCC) plants as baseload plants. Where available, hydroelectric units are also used as baseload or intermediate load plants. Finally, peaking generators meet the more extreme spikes in demand and often are used for only a few hours of the year. Peaking generators are typically “simple cycle” gas turbines or older gas- or oil-fired steam generators.[5] Peaking plants are relatively inexpensive to build but are more expensive to run because they are generally less efficient than other types of plants or use more expensive fuel. In planning and daily operations, system operators tend to choose the mix of generators that allows them to meet demand in the most economic fashion. Determining this mix is an important part of planning the power system.

The emergence of wholesale energy and capacity markets has led some of the planning to be replaced by market mechanisms, but developers still examine patterns of load growth, system requirements, and expected utilization to determine the type of plant to construct.

ENERGY EFFICIENCY

Energy efficiency improvements reduce the amount of electricity required to provide a particular end-use service, such as lighting or air-conditioning. For example, more efficient devices such as light-emitting diode (LED) light bulbs provide the same amount of light (lumens) as traditional incandescent bulbs, but use a fraction of the energy. Reducing end-use consumption of electricity through energy efficiency improvements can displace the need for new capacity. For example, because most of the

[5] In some locations, peak demand is met with pumped storage plants, which store energy by pumping water up a hill to a reservoir and then release that stored energy through a conventional hydroelectric generator during periods of peak demand.

United States has peak demand in the summer, more efficient air conditioning can maintain comfort levels with less power, and more efficient lighting that loses less energy to heat would, in turn, make buildings easier to cool and lower demand on air conditioning systems.

DEMAND RESPONSE AND INTERRUPTIBLE LOAD

DR and interruptible load are additional tools that can be used to reduce the need for capacity without impacting levels of service. Instead of building new capacity, utilities can provide incentives to (or pay) electricity users to reduce demand (often referred to as conservation) or to shift demand to parts of the day with lower demand (often referred to as load-shifting), thus reducing the overall need for capacity. Such programs can be cost-effective as long as the cost of incentive payments is less than the cost of new generation capacity.

Historically, large industrial and commercial customers have been offered "demand-based" or "interruptible" rates.[6] Under demand-based plans, utilities charge customers a higher rate for usage during peak demand periods. This provides incentives for large industrial consumers to reduce demand during these periods, which in turn reduces the need for peaking capacity. Under interruptible rate structures, in exchange for offering lower electric rates, the utility reserves the option to limit or turn off electricity supply to the customer under certain defined circumstances. These rates structures are very rare for smaller consumers such as households because of the need for (historically) expensive communications and metering equipment. However, that is changing, as discussed below under "Smart Grid Technologies."

Utilities also offer DR programs for residential customers. A common type is direct load control (DLC) programs. DLC programs allow utilities to directly control certain appliances—most frequently air conditioners and electric water heaters—to reduce peak demand.[7] In exchange for a reduction on the customer's bill, the utility installs a remotely controlled switch on the appliance and receives the right to occasionally turn off the appliances for short intervals, often 15 - 30 minutes.[8] For most consumers the interruption of service is rarely noticeable.[9] More recently, new classes of demand-response programs are available through the emergence of wholesale markets; see "Smart Grid Technologies" below.

TRANSMISSION

Finally, transmission is another tool for increasing power system reliability during periods of peak demand. Transmission provides better access to available power sources. Transmission allows regions to share resources, so that if a generator fails in one region, generators in another region can provide power to the affected area. Transmission can also link regions with non-coincident peak demand for

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[6] For a comprehensive overview of the principles of utility rate structure design, see Bonbright et al. (1988).

[7] A survey of residential DLC programs is provided at https://www.clearlyenergy.com/residential-demand-response-programs/.

[8] Examples of DLC programs with different cycling requirements are provided at http://www.constellation.com/business-energy/demand-response/pages/capacity-programs.aspx and http://www.coned.com/energyefficiency/demand_response.asp.

[9] Utilities can also employ conservation voltage reduction which reduces power consumed by appliances. This is only utilized under extreme conditions to avoid blackouts.

electricity (such as the Northwest and California), therefore sharing resources and reducing the need for peaking capacity. Transmission, therefore, can effectively act as a source of reliable capacity even in the absence of adding any new generation within a particular area. Transmission upgrades can also act to reduce losses, improving the efficiency of delivery and reducing the amount of capacity needed to meet peak demand (Jackson et al. 2015).

COMPLYING WITH RULE 1: NEW OPTIONS

Today, new technologies provide utilities with new options for meeting peak demand and providing reliable service. These options include variable generation (VG) like wind and solar power, smart grid technologies and energy storage. These new options also provide new opportunities for DR programs. Many of these options are relatively inexpensive and fast to deploy, especially as compared to constructing traditional large, conventional power plants.

VARIABLE GENERATION

The cost and performance of VG resources like wind and solar photovoltaic (PV) systems have greatly improved over the past decade, providing power system operators with viable new tools that can meet peak demand. Due to their variable output, these new technologies are quite different from traditional generation resources. Wind and solar units are only available to generate electricity when the wind is blowing or the sun is shining, and for this reason they are often referred to as “variable generation” resources and do not fit the traditional paradigm of building capacity to meet baseload, intermediate, or peaking needs. Nonetheless, they can provide power during times of peak demand and be used to meet reserve margins.

The value of a VG resource toward providing reliable capacity to meet planning reserve margins is measured by its “capacity credit,” which is a ratio of the power output during peak demand periods and the rated (nameplate) capacity of the variable resource.[10] If a PV generator is rated at 100 MW, but only typically produces 55 MW during peak demand periods, then the capacity credit for that generator would be 55%. Studies of capacity credit show wide variation. The capacity credit for a fossil fuel or nuclear plant is typically 90%–95%.[11] Because wind resources are not typically well-correlated with peak demand, wind capacity credits are generally low – in the range of 5%–40% (Keane et al. 2011). Capacity credits for PV vary as well, as shown in Figure 2, but at low penetrations (less than 5%); capacity credits range from approximately 30%–75%. The large range of estimates results from both methodological differences and the regional variation in the coincidence of wind and solar generation with peak demand. For example, peak loads in cooler climates such as the Pacific Northwest may be driven by electric heating demand, which occurs during times of low solar output. Likewise, the wind output in the United States tends to be lower during hot, sunny afternoons when air conditioning demand typically peaks.

[10] This explanation is a simplification of the calculations used to estimate the capacity credit of new generation resources. For details, including a glossary of terms, see Madaeni et al. 2012.

[11] Fossil and nuclear plants typically receive a capacity credit less than 100% due to unplanned plant outages and summer derates.

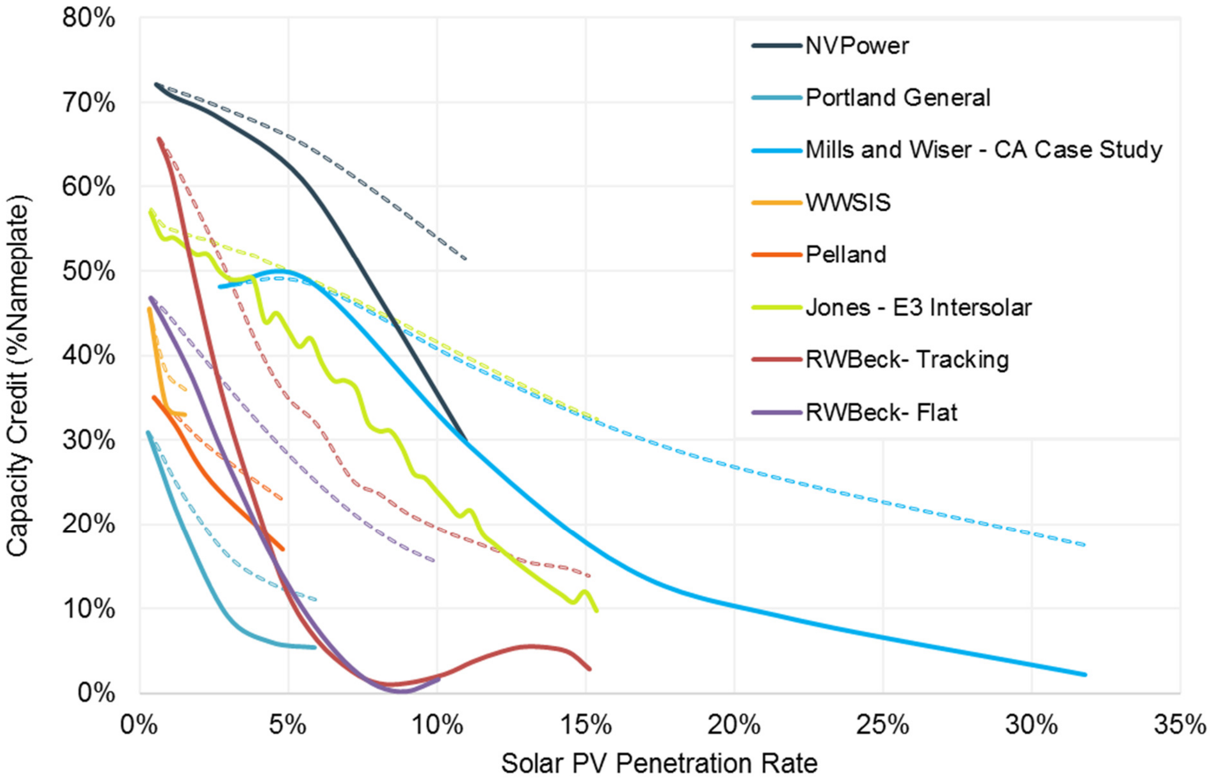

Figure 2. Capacity credit of PV as a function of penetration for different regions. Dashed lines are average (fleet-wide) capacity credit while solid lines are marginal capacity credit.

Because VG is not dispatchable, the contribution of VG to meeting reserve margins is often measured by how it changes what is called "net load". Net load is equal to the normal load minus wind and solar generation.[12] The result of this subtraction is the amount of load that must be met by conventional, dispatchable generation. An important feature of Figure 2 is that the capacity credit declines with penetration. This is because increasing amounts of solar generation on the system changes the time when peak net load occurs.

This shift in peak net load is illustrated in Figure 3, which shows the load for three days in California, using simulated solar data at increasing penetration (Denholm et al. 2016). At low penetration (5% and 10% in Figure 3), PV reduces the peak net load (*i.e.*, the peak of the demand minus PV generation). But at higher penetrations (15% and 20%), the peak net load does not continue to decline because the peak has shifted to later in the day when PV is not generating. While PV continues to reduce demand during the original peak period (about 4 p.m.), the new peak between 7 p.m. and 8 p.m. is not reduced.

[12] Some sources define net load as load minus *distributed* generation. The definition we use here encompasses all wind and solar generation.

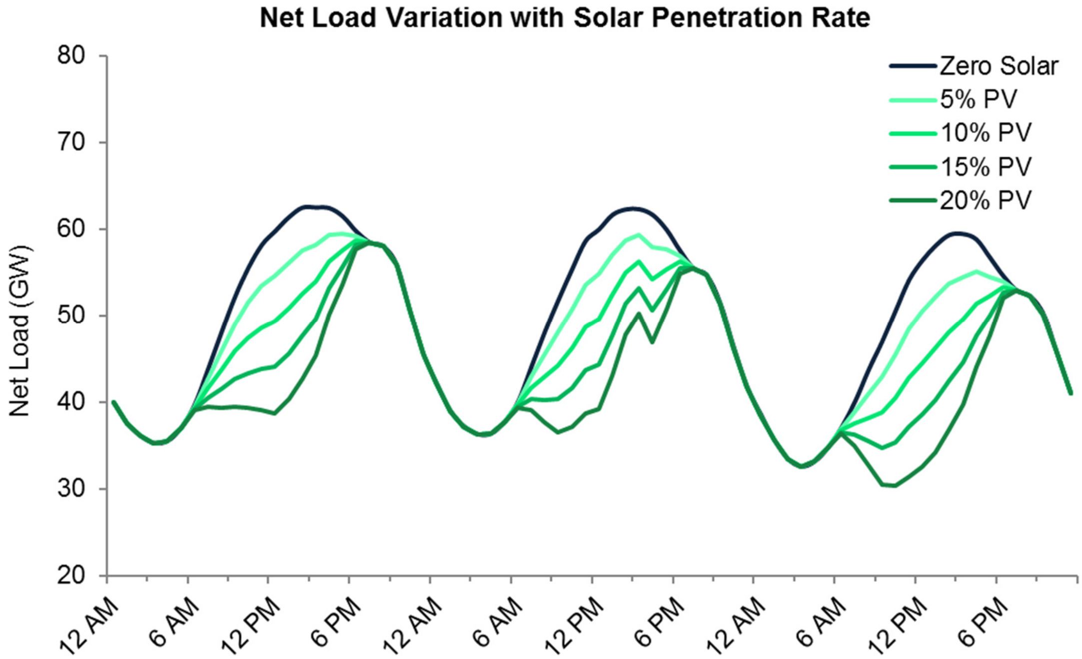

Figure 3. Load and net load profiles for California under increased penetration of PV for three representative days of peak demand in the summer

There are several options that can increase the capacity credit of VG resources. New transmission can interconnect regions with different renewable energy (RE) resources and load patterns, which in turn can increase the correlation between VG and peak load. Finally, there are a number of dispatchable (on-demand) RE sources, including biomass, geothermal, and concentrating solar power with thermal storage that provide both energy and capacity. These technologies can receive capacity credit equal to those for conventional (dispatchable) generators.

DEMAND RESPONSE AND SMART GRID TECHNOLOGIES

While EE and DR have been part of utility planning for decades, the emergence of smart grid technologies enables even greater opportunities for changing load shapes and reducing peak demand and, hence, the need for traditional capacity to meet resource adequacy requirements. Smart grid technologies include new devices such as smart meters and appliances that “talk” to the utility. These types of devices allow for the use of innovative rate structures and other mechanisms to more cost-effectively balance the demand and supply of electricity. In the United States, most residential customers are charged based on how much total energy they use independent of when they use it. However, these rate structures hide the true costs of electricity because the cost of generating electricity at different times of the day and different times of the year varies dramatically. Thus, electricity rates that only consider total consumption of electricity, but not when it is used (sometimes called volumetric rates), do not provide incentives for load shifting. Despite this, volumetric energy rates have been the norm because technologies to measure electricity use more accurately have been expensive, and rates that vary with the time of day or year, or rates that vary with usage can be more difficult for consumers to interpret. Modern smart grid technologies have reduced these metering costs and can now provide consumers and utilities with information that better reflects the true costs of electricity consumption in end-user rates and, therefore, offer incentives to consumers to conserve or shift usage to periods of lower demand. As more consumers shift their usage to periods of lower rates, peak capacity needs (and therefore overall costs) can be reduced.

The total cost of providing electricity includes the cost of both capacity and energy.[13] Capacity costs include building generators, transmission lines and distribution lines. Energy costs are the costs of buying fuel to run the generators and the costs of operating them. Customer usage patterns determine how much capacity and energy is needed and the corresponding costs that customers actually incur. Flat rates, however, do not reflect differing patterns of consumption among consumers and may over-charge or under-charge customers based on when customers use electricity.

To illustrate how this works, Figure 4 shows the hypothetical electricity consumption patterns for three different consumers. All use the same total amount of energy during a day, but their pattern of usage is very different. Consumer A's demand for electricity is relatively flat. Consumer B's use sharply spikes in the middle of the day but is lower at night. Consumer C's usage is more typical of the average consumer, and utilities commonly employ this typical usage profile to set flat rates.

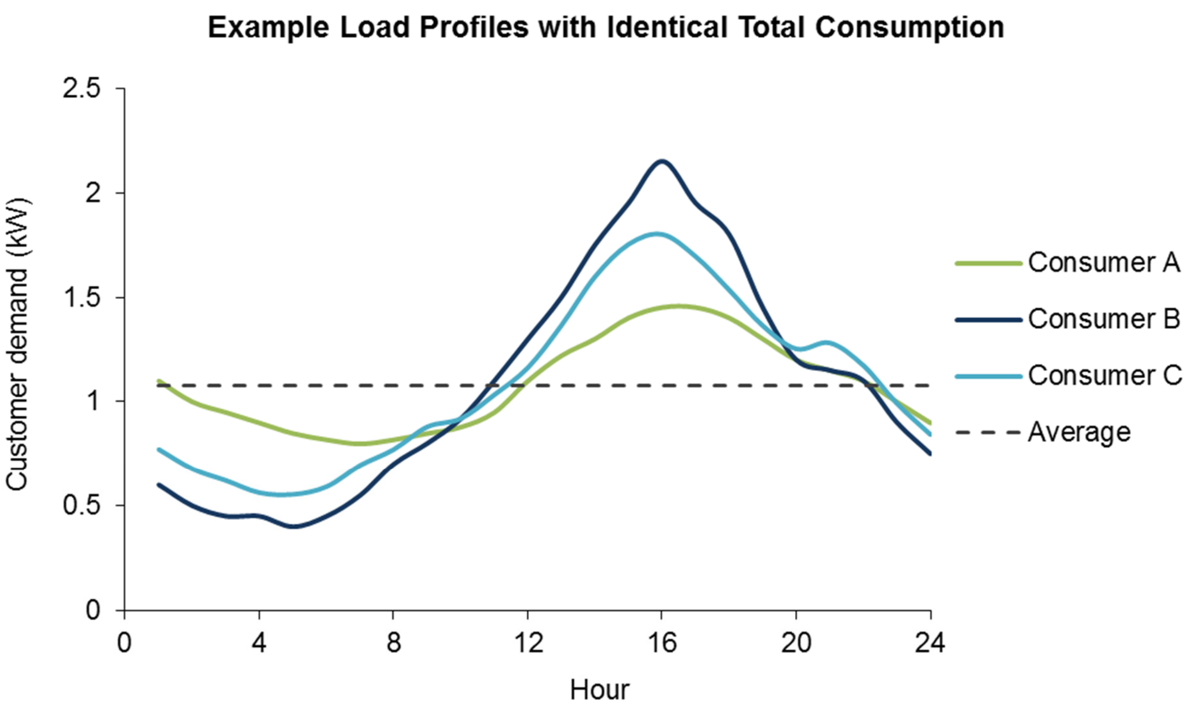

Figure 4. Example of identical energy use with different consumption patterns during a 24-hour period

Flat, energy-only retail rates ignore the potentially significant differences in capacity that each customer requires to serve its load. In the Figure 4 scenario, the utility would need to build more capacity to meet

[13] The cost to provide the capacity and energy needed to provide reliability are often separated out. These costs are typically small when compared to capacity and energy costs needed to directly serve load but are needed to provide necessary services to run the power system. Some of these are discussed under rules 3 and 4.

Consumer B's demand. However, because Consumer B uses the same amount of electricity as Consumers A and C, under a volumetric rate she would be charged the same amount. As a result Consumer C would overpay for her "share" of the power system, while Consumer B would underpay, because of her greater than average need for generation capacity.

Smart meter and grid technologies allow rates to be set that reflect the differences in cost of providing energy to meet these different load profiles and, therefore, are more proportional to actual consumption of services (both energy and capacity). Until recently, such technology was available but prohibitively expensive for use by most residential consumers. Costlier meters and measuring practices have been available to large commercial and industrial customers for some time.

Though still relatively rare, a number of new rate structures are now available to residential consumers thanks to smart grid technologies. For example, demand-based rates charge the customer separately for both the energy used and the capacity required to meet their load. A demand-based rate structure imposes a per-kW (not per-kWh) charge based on the customer's peak demand during each billing cycle. A demand charge is used to pay for the cost of building and maintaining the generation, transmission, and distribution capacity to meet that customer's peak demand. A separate energy charge covers the cost of fuel and other costs associated with operating generators and other parts of the grid. With these more direct price signals, consumers have more information to adjust their demand or usage patterns, which can reduce the need for new capacity. In the Figure 4 example, Consumer B's rates would go up to reflect the true cost of providing service, and, conversely, Consumer A's rates would decline.

Alternatively, utilities can also use energy prices that vary throughout the day as generation costs change. This structure is typically referred to as time-of-use pricing. With time-of-use pricing, utilities charge different rates for electricity during different parts of the day. Other options include real-time pricing and other rate structures that tie consumption patterns to actual costs. Real-time prices are established by the actual cost of generating and delivering electricity during any given moment in time. When prices are very high, smart appliances and devices could be programmed by the consumer to reduce load, reducing the need for new generation capacity.

ENERGY STORAGE

Energy storage in the form of pumped hydro storage has long been a part of electric power system planning and operation. Storage can provide an alternative to conventional capacity by storing electricity during off-peak periods (historically during the early morning) and discharging during peak hours. Off-peak charging can improve the efficiency of the power system by allowing the lowest operational cost generators to remain online, while on-peak discharging tends to displace the highest cost generators. This requires storage to have a sufficient number of hours of energy generation to cover the peak demand period, which is typically up to eight hours in duration (Sioshansi et al. 2014). As discussed in the following section, PV may decrease the length of the peak demand period and reduce the storage capacity needed to meet peak demand, lowering costs. Beyond pumped hydro storage, a number of emerging or not widely deployed storage technologies can also enhance reliable operation by providing capacity. These technologies include compressed air energy storage, flywheels, new battery technologies as well as various types of thermal energy storage. Thermal storage, such as storing ice produced during off-peak periods, can reduce on-peak air conditioning demand and lessen the need for additional peaking capacity.

SYNERGIES BETWEEN PV, DR, AND ENERGY STORAGE

Beyond the ability of PV, DR, and energy storage to separately provide capacity and replace conventional generation, they also can work together to provide further benefits. By reducing the duration of the peak demand period, PV can reduce the cost of energy storage needed to provide reliable capacity, as well as increase DR availability. As shown previously in Figure 3, PV changes the shape of the net load curve. This is shown in more detail in Figure 5, which illustrates two changes at increased penetration of PV. First, there is a reduced amount of time between on-peak and off-peak periods. Second, the overall on-peak period narrows. Reducing the amount of time between on-peak and off-peak periods creates opportunity for DR. DR (particularly load-shifting DR) requires a load that can be used earlier or later than would normally occur.

The second impact of solar on net load shape is the narrowing of the peak period. Figure 5 demonstrates how, in the summer, the number of hours of peak demand becomes shorter. Previous analyses suggest that in a system with little or no PV, as much as eight hours of storage capacity may be needed to achieve the same level of reliability as a traditional generator (Sioshansi et al. 2014). Long-duration batteries with this amount of energy capacity are costly. Increasing VG penetration and narrowing the peak demand period creates opportunity to meet demand using more affordable, shorter-duration batteries. However, a narrower peak may also require additional flexibility on the system as is discussed in the next section.

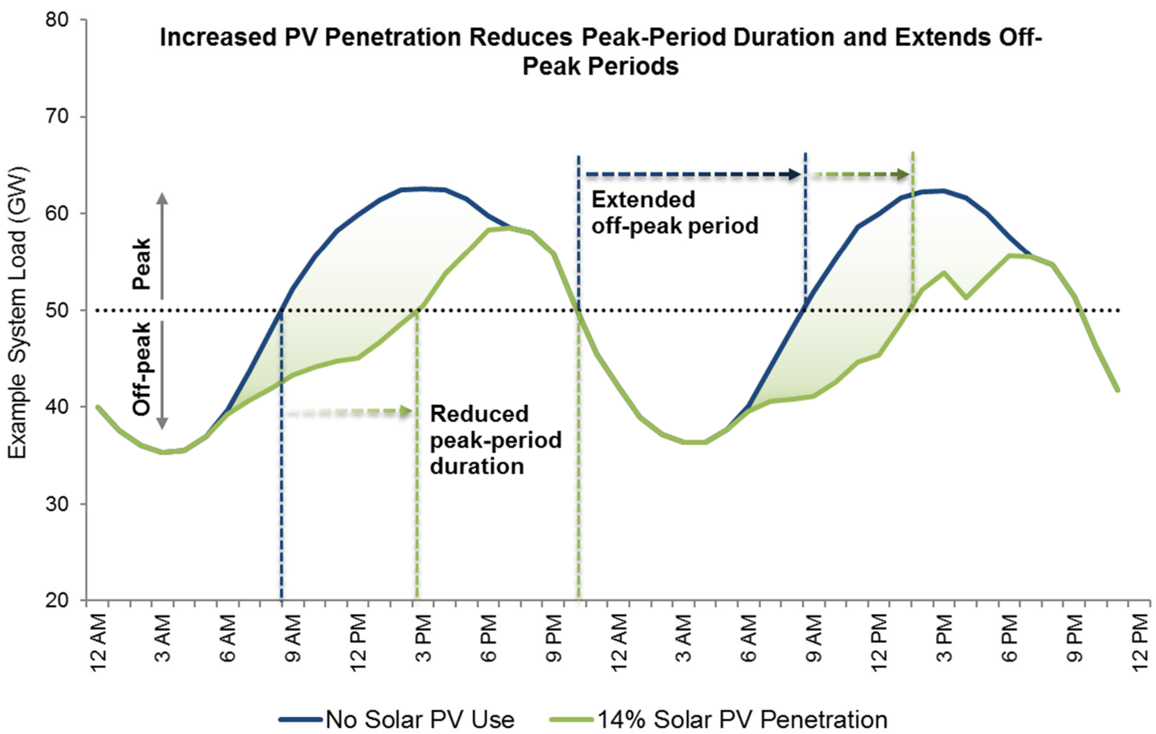

Figure 5. Increased PV penetration leads to shorter intervals of peak demand

RULE 2: POWER SYSTEMS MUST HAVE ADEQUATE FLEXIBILITY TO ADDRESS VARIABILITY AND UNCERTAINTY IN DEMAND (LOAD) AND GENERATION RESOURCES.

WHY FLEXIBILITY MATTERS

The demand for electricity varies from minute to minute and hour to hour, so grid operators constantly vary the output from conventional generators to meet the variation in demand. Figure 1 in the previous section shows that the demand for electricity varies significantly over a 24-hour period, with demand in the summer almost doubling over the course of a day. As a result, even in the absence of any VG, system planners need to ensure adequate system flexibility to accommodate highly variable demand on both an hourly and seasonal basis. Increasing amounts of VG sources like wind and solar increases the variability of net load. Therefore, a power system with increasing VG needs to be even more flexible to balance supply and demand.

Figure 6. illustrates the impact of wind on net load, which, as noted earlier, is the power demand that must be met by conventional generation. In this example, both the net load ramp rate and net load ramp range increase, and, as a result, conventional generators must change output more than has historically been required. For example, in the figure, on April 8, the system operator would normally need to increase output from the generation fleet by as much as 4,000 MW per hour (blue line). With added wind generation (red line), the system operator would instead need to increase output by as much as 5,500 MW per hour to account for the increased variability in net load (green line), an increase of 1,500 MW per hour. As shown previously in Figure 3, solar PV can also increase the net load variability.

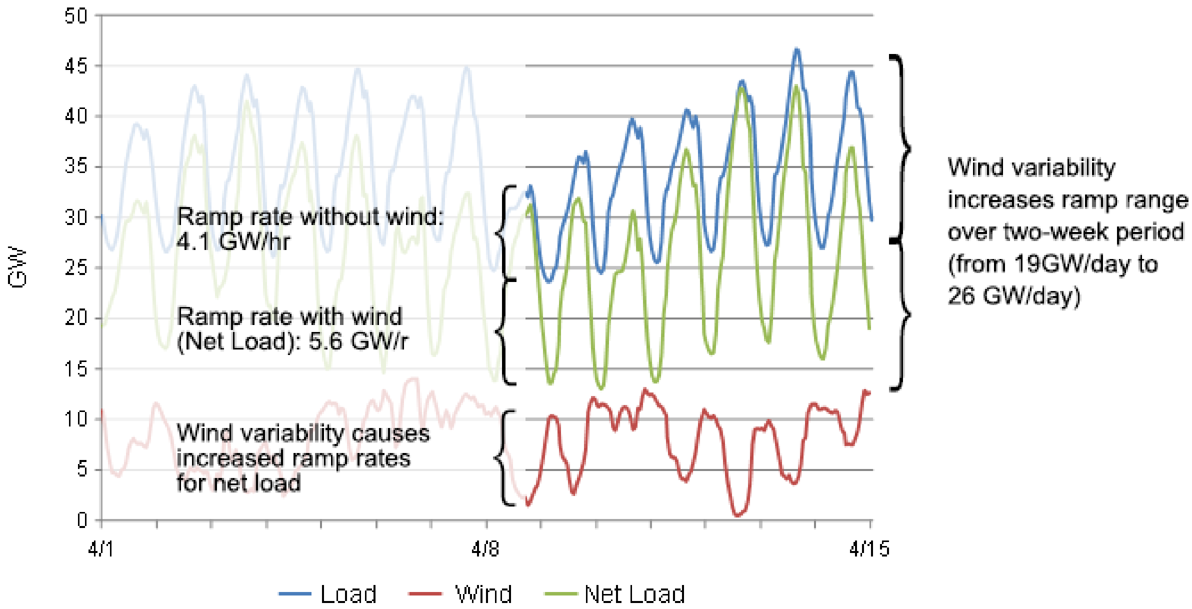

Figure 6. Increase in net load variability with added wind

COMPLYING WITH RULE 2: TRADITIONAL MEANS

As discussed in Section 1, variation in demand is typically met with intermediate-load or peaking plants (often gas-fired) that can vary output on an hourly or sub-hourly basis. These units are used to meet most of the day-to-day variation in demand, varying generation from low output during periods of low demand to high (or full) output during periods of higher demand. Many of these plants may also turn off during the evening or in the spring when demand is typically at its lowest. During hot summer days, when demand is at its highest level, operators utilize peaking plants, which can start quickly and are often run for just a few hours during the day.

Recent analysis has demonstrated that the current fleet of installed generation can typically provide sufficient system flexibility to accommodate significant increases in wind and solar generation (Cochran et al. 2015, Lew et al. 2013; Bloom et al. 2016). These studies of systems with up to 35% VG demonstrate that existing resources that are "backed down" to accommodate VG can typically ramp rapidly enough to provide load following at 5-minute dispatch time scales [see text box "System Ramping"]. The implication of this finding is that, while VG can increase ramping requirements, the existing generation fleet is largely adequate to meet this requirement. The average age of the gas combined-cycle fleet and combustion turbine fleet in the United States is 12 and 16 years respectively (EIA 2016), so this capacity can provide grid flexibility services for the foreseeable future.

System Ramping

Power system operators have historically dealt with often highly fluctuating demand in electricity. For example, in 2006 the maximum 3-hour ramp observed by the California Independent System Operator was 11,072 MW as load ramped up from 30,252 MW to 41,342 MW the morning of July 22. By planning and careful forecasting, the system was able to increase the output of the generator fleet to meet this change in demand. In 2014, the maximum 3-hour ramp rate had actually dropped to 7,859 MW, in part due to the impact of distributed PV, which reduces the summer-time ramp rate (observable in Figure 5). As PV penetration increases, the peak demand will shift from summer to spring, and the CAISO predicts a PV-driven 3-hour ramp of about 13,000 MW, or about 15% higher than the 2006 ramp.

COMPLYING WITH RULE 2: NEW OPTIONS

Even as traditional means suffice to comply with Rule 2, much more can be done to increase the flexibility of the grid and reduce costs while maintaining reliability. Analysis and recent experience indicate that new policies and operational procedures can help the power system accommodate increases in net load variability. Many of these are targeted toward unlocking flexibility that already exists (CPUC 2015). For example, there may be contractual agreements that prevent a generator from ramping (Lew et al. 2015).

In addition, regions throughout the United States are creating new incentives and standards for system flexibility. Proposed standards typically set a flexibility requirement and allow market participants to choose among existing or emerging technologies to meet the requirements. For example, the California

Public Utilities Commission requires that load-serving entities under its jurisdiction (primarily the state's three large investor-owned utilities) procure capacity with sufficient flexibility to address the largest predicted 3-hour ramp rate in each month (CPUC 2014). Other system operators are developing tools and practices to address shorter-duration ramps, particularly those created by solar and wind resource uncertainty, by requiring flexibility reserves. While the specific technical requirements have yet to be defined, flexibility reserves represent the ability to change generator output (or, in the case of demand response, load) in response to forecasting errors associated with short-term variations in load or VG resources (Xu and Tretheway 2012; Navid et al. 2011).

Newer, more flexible generation technologies are also available. For example, gas-fired generators tend to be more flexible than coal-fired generators. If coal units were to be replaced with more flexible gas-fired units as they retire, system operators would increase their ability to rapidly adjust generation. Certain types of modern gas-fired generation are capable of very fast ramp rates, and certain new gas-fired combustion turbines and reciprocating engines are capable of very short start times [see text box "Flexible Generators"]. These units can provide flexibility reserves without being online, avoiding the need to operate a plant at less than its full potential output, which can reduce efficiency and increase costs. In addition, certain coal units and potentially some nuclear units are capable of operating flexibly.

However, many of the new and emerging technologies that provide conventional capacity (discussed in Rule 1) can also be used to provide grid flexibility, reducing the need to construct new natural gas plants to provide flexibility. Advanced biomass and concentrating solar power equipped with thermal energy storage provide fast ramping capability (Jorgenson et al. 2014). DR with the appropriate pricing signals can be used to vary load in response to extreme or unexpected ramp events, and most storage technologies can ramp as fast as or faster than conventional generators (Ma et al. 2016). Finally, VG itself can be used to mitigate ramp events via curtailment (reduction in output from a generator from what it could otherwise produce

Flexible Generators

Several modern generator types are capable of starting and reaching full load in as few as 5–10 minutes. These include aeroderivative gas turbines and reciprocating engines. Aeroderivative turbines are similar to traditional gas turbines, but the moving parts are derived from aircraft jet engines and are therefore very light. This allows the turbines to change output rapidly in response to the variation in demand that can be created by wind and solar resources. Reciprocating engines, similar to vehicle engines, can also start rapidly. Both aeroderivative and reciprocating generators have been installed in locations needing generators that can provide responsive capacity without the need to keep traditional generators online.

Dispatching Wind

In several regions of the country, wind has become a dispatchable resource. The output of wind energy can be controlled to reduce output when the supply exceeds demand. Operators can also deliberately reduce output in order to ramp the plant up and down to follow load or provide reserves. Using dispatchable wind, one utility (Xcel Energy in Colorado) has been able to serve over 60% of its load with wind power during certain hours of the year (Bird et al. 2014).

given available resources) [see text box "Dispatching Wind"]. Curtailment of VG incurs the cost of lost energy production and is typically avoided, but occasional curtailments can be effective for helping balance supply and demand, managing transmission overloads and maintaining system reliability. Specifically, curtailments can be less costly than shutting down and starting up a conventional power plant for a few hours during short periods of high VG output.

RULE 3: POWER SYSTEMS MUST BE ABLE TO MAINTAIN STEADY FREQUENCY

WHY STEADY FREQUENCY MATTERS

The U.S. power grid uses alternating current, meaning that the flow of electricity in a power line switches direction rapidly. This change in direction is measured by its frequency, the number of times per second the current changes direction. In the United States, the frequency is 60 cycles per second (Hertz, abbreviated Hz).

The frequency is determined by how fast the generators spin. All conventional fossil, nuclear, and hydroelectric generators are "synchronous" generators, meaning they are all "synchronized" with each other spinning at some multiple of 60 Hz (see text box "Spinning Generators"). Figure 7 provides a simplified representation of the existing grid. The blue motors represent synchronous generators that all act in unison to "spin" the grid at 60 Hz. The coupling (synchronization) of the generators to the grid is represented by the chains.

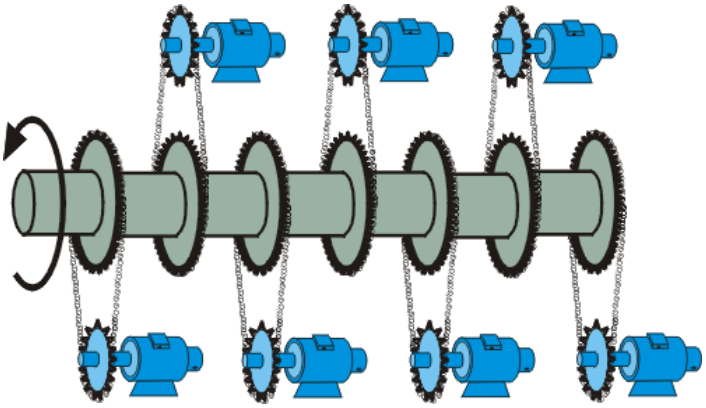

Figure 7. Representation of the existing grid powered by synchronous generators

It is important for this frequency to remain constant. Many motors and other machines are designed to operate based on receiving 60 Hz electricity. If the frequency were to change significantly, machines and electronics can be damaged. Automatic controls help prevent extreme damage from frequency changes. If the frequency drops beyond a certain point, protection systems automatically initiate "under-frequency load shedding" and disconnect a certain part of the grid (neighborhoods, city blocks, etc.). This protects the machinery but at the cost of a blackout for some of the grid. The ability to maintain a stable frequency prevents a single plant or transmission line failure from triggering a wide-spread power outage.

To maintain system frequency and avoid power outages, system operators employ *operating reserves* that are able to respond to unplanned events. These events can be a short as a few seconds or minutes due to unexpected changes in load or generation not accounted for under economic dispatch, or as long as days or weeks in the event that a transmission line or power plant fails. Operating reserves represent spare capacity to deal with this unplanned variability of demand or supply, including unplanned outages that can occur rapidly. If one of the generators in Figure 7 were to fail unexpectedly, the other generators must have enough capacity to provide the needed electricity, while maintaining a frequency of 60 Hz.

To understand the relationship between frequency and operating reserves, we will discuss the four types of reserves that respond to a large mismatch between supply and demand. While there is not a uniform set of definitions of terms used when discussing operating reserves, many system operators describe four general classes of reserves that are used to help maintain frequency:

- Frequency responsive reserves (inertia and governor/primary frequency response)
- Regulating reserves
- Contingency spinning reserves
- Non-spinning/supplemental reserves

Spinning Generators

Spinning generators are power generators that are online (spinning) and synchronized to the grid. These generators are directly coupled to the electric grid (see Figure 7) so are able to quickly respond to system faults and help maintain system frequency. Spinning generators include hydroelectric generators, gas turbines, and steam generators that use heat generated from nuclear energy or burning fossil fuels.

In cases where there is a significant event that could result in a change of frequency, such as a large power plant failure, these reserves are typically used as needed in sequence as illustrated in Figure 8 and described below.

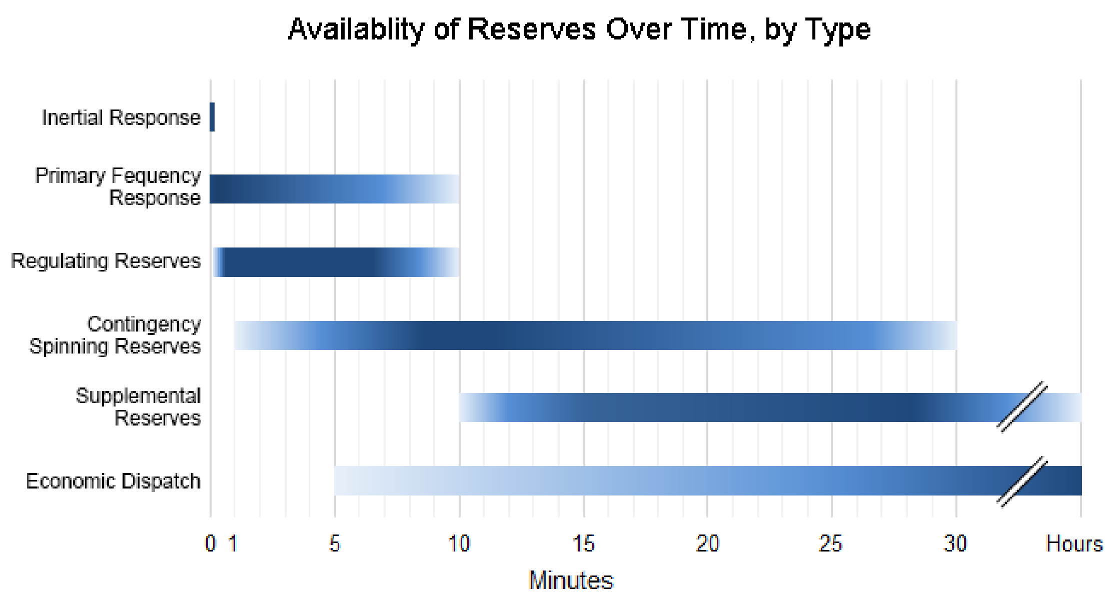

Figure 8. Sequence of reserves activation in response to a contingency event such as a large power plant failure

Figure 8 illustrates the time scales over which different types of reserves are deployed in response to an unexpected mismatch between supply and demand. As the figure shows, resources with different technical characteristics are deployed at different times – typically, they are deployed in order from very fast to slow (and with corresponding costs that range from more to less expensive). This cascade of resources is designed to contain costs while maintaining reliability. In some cases, not all types of reserve are needed to return the grid to its normal state, which we will refer to as "economic dispatch." Each type of resource is described in order of deployment below:

1. **Frequency Responsive Reserves**
   - A. **Inertial Response.** When there is mismatch in the supply and demand for electricity, the frequency of the grid will begin to change, but the inertia of the generators on the grid will delay that process (inertia is the physical property of spinning machines that reduces rate of change of frequency). When this occurs, all the spinning generators currently synchronized to the grid will continue to spin due to their stored inertia. However, the frequency of the system will begin to change as more energy is removed from or added to the grid due to the mismatch between supply and demand. The rate at which the frequency changes is determined by the magnitude of the imbalance between load and generation and the total inertia of the system. Large spinning generators on the grid can slow the rate of change in frequency and provide time for systems to detect those changes and respond accordingly.
   - B. **Primary Frequency Response.** Primary frequency response is one of two parts of the "cruise control" of the electric power system. Primary frequency response (sometimes known as governor response) detects changes in frequency and automatically adjusts operations of online generators to maintain frequency within the desired range. Governors (the devices that sense frequency) can be installed on any conventional fossil, nuclear, or hydro generator, but grid disturbances are typically not so large that governors are needed on all generators.
2. **Regulating Reserves.** While inertia and primary frequency response occur system-wide and work automatically to prevent large frequency deviations, additional actions are needed locally to restore the system to its "pre-event" state—spinning at 60 Hz with all generators operating as scheduled. Regulating reserves are the second part of the "cruise control" of the power system that works to reset the system to "normal" conditions and correct any imbalance resulting from localized mismatches between supply and demand. Systems can measure the unscheduled flow of power into or out of the region where local generation is not matching load, and computers can signal generators in that area to modify their output as needed. Regulating reserves are provided by any synchronized (spinning) generation/storage resources that can receive these automated signals and rapidly ramp (begin changing output within seconds and reach the new desired setpoint within minutes).
3. **Contingency Spinning Reserves.** A power plant or other significant failure is often referred to as a "contingency." When a contingency occurs, the automated "cruise control" systems listed above take action to correct and restore frequency and power flows. Systems do not typically have enough primary frequency response capacity and regulating reserves to handle large contingencies. Furthermore, the use of these services depletes their effectiveness for further response, such as another contingency or other unscheduled variation in supply or demand. System operators address large contingency events using a dedicated class of reserves known as contingency spinning reserves. Spinning reserves are like an additional synchronized engine that can be engaged quickly when needed to maintain performance. They are provided by partially loaded conventional generation/storage resources, with enough spare capacity (in aggregate) to meet the failure of the single-largest power plant or transmission line in the system.
4. **Non-spin/Replacement/Supplemental Reserves.** If contingency reserves are engaged, system operators must eventually restore them to a reserve status. Otherwise, another contingency could find them without enough spare capacity to meet this second event. To prevent this, power system operators hold supplemental reserves, which are typically fast-starting units that can start and begin providing energy within about 10 minutes. System operators activate

supplemental reserves to "relieve" the contingency reserves units so that they are ready to be called upon again. Any plant that can begin generating within 10 minutes can provide these reserves.

5. **Economic Dispatch (normal system operation).** Non-spinning reserves are eventually replaced by the normal economic dispatch of conventional generators, as the system is restored to a pre-contingency state.

COMPLYING WITH RULE 3: TRADITIONAL MEANS

Traditionally, conventional resources such as coal, gas, and nuclear power have provided nearly all of the system's inertia, primary frequency response and regulating reserves. An important point is that, while reserves are an important part of reliable system operation, the amount of reserves needed is relatively small compared to the total capacity requirements. Table 1 summarizes the regulating and spinning contingency reserve requirements held by different operators and demonstrates that larger areas can typically carry fewer reserves on a relative basis due to the fact that a greater aggregation of supply and demand reduces overall variability.

Table 1. Regulating and Spinning Contingency Reserve Requirements in U.S. Wholesale Markets

Region	Regulating Reserve	Spinning Contingency Reserve	2013 Demand
CAISO	average (varies): ~338 MW up, ~325 MW down	~850 MW (average)	peak: 45,097 MW average: 26,461 MW
ERCOT	average (varies): ~300 MW down, ~500 MW up range: 400–900 MW	2,800 MW (maximum of 50% from load)	peak: 67,245 MW average: 37,900 MW
MISO	range: 300–500 MW	1,000 MW (2,000 MW total and 1,000 MW of spin)	peak: 98,576 MW average: 52,809 MW
PJM	average: 753 MW in 2013[e]	1,375 MW (Tier 2; maximum of 33% from DR)[f]	peak: 157,508 MW average: 89,560 MW
ISO-NE	average 60 MW range 30–150 MW	10-minute reserve: 1,750 MW 30-minute reserve: 2,430 MW	peak: 27,400 MW average: 14,900 MW
NYISO	150–250 MW	10-minute spin: (330 east zone, 655 MW NY control area 10-minute total 1,310 MW	peak: 33,956 MW average: 18,700 MW
SPP	average: ~300 MW up, ~320 MW down	545 MW	peak: 45.256 MW average: 26,360 MW

Source: Denholm et al. 2015

COMPLYING WITH RULE 3: NEW OPTIONS

The current transformation of the grid affects Rule 3 in many ways. The increased deployment of VG changes the reserve requirements needed to maintain a steady frequency on the grid. At the same time, it is possible for VG to provide the needed reserves at little additional cost, and there are also new technologies like energy storage and demand response that can provide needed reserves.

VARIABLE GENERATION

VG impacts reserve requirements in several ways. First, it reduces generation from conventional generators, and the inertia in generators that are not operating is thus removed from the system. VG such as wind and solar uses power electronics (inverters) rather than synchronous generators to connect to the grid, so it does not replace the physical inertia from conventional generators. As a result, replacing conventional generation with VG typically reduces real inertia and traditional frequency response. Figure 9 illustrates a grid where some of the synchronous generators have been replaced with inverter-based generators (illustrated in green). These generators are “loosely coupled” to the grid and do not automatically respond to a grid fault.

VG also is not always completely predictable, even on short timescales. This can increase the potential for mismatches between generation and load and, hence, the need for increased regulating reserves. Several studies and real-world experience of power system operators indicate that increasing the amount of VG on the system slightly increases reserve requirements to maintain frequency stability (Ela et al. 2011). VG increases variability of the net load on various timescales, including very short time scales. As a result, an important area of study has been to estimate the change in reserves needed to address this increase in net load variability.

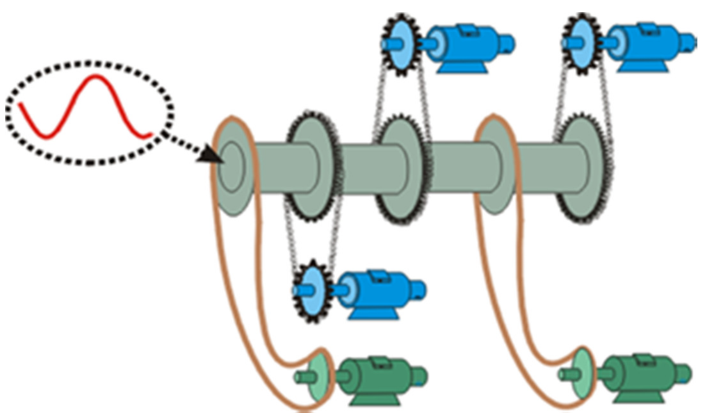

Figure 9. Representation of a grid with both synchronous and inverter-based generators

Table 2 summarizes several studies that consider the additional reserves needed when wind power is added to a power system. These studies demonstrate a modest increase in regulating reserve requirements. Furthermore, recent experience has demonstrated little need for additional regulating reserves. As an example, MISO found that the addition of 12 GW of wind resulted in no need for additional regulating reserves (Navid 2013). While this result may be surprising, it highlights the timeframe of the variability of wind. The output from wind does not change drastically over seconds or even a few minutes, and thus the need for additional regulating reserves is limited. Furthermore, over longer time scales, improved wind forecasting has decreased the need for operating reserves needed to address wind uncertainty (Milligan et al. 2015).

Despite rapid growth in recent years, the penetration of PV is still quite low, and, as a result, the impact of PV on reserve requirements has yet to be determined. While the output of a single PV system can change rapidly due to passing clouds, over large regions the aggregated output of many PV systems is much smoother and easier to predict. Variability in PV output is thus driven by longer-term weather impacting output over periods of many minutes to hours. This type of variation is the driving motivation to create a new “flexi-ramp” reserve product, which can create a more economic method to incorporate VG. VG also does not add to the need for contingency spinning reserves (those used to address the largest single point of failure in the system) unless a single wind or solar plant (or a transmission line collecting multiple wind/solar generators) becomes the single-largest contingency (point of failure).

Table 2. Additional Regulating Reserve Requirements Due to the Addition of VG

Location	VG Added/ System Size	Increase in Regulating Reserves
New York	3,300 MW of wind on system with projected peak load of 33,000 MW	36 MW
Minnesota	5,700 MW of wind on system with peak load of 20,984 MW (providing 25% of total demand)	20 MW
Arizona	1,260 MW of wind providing 10% of annual demand	6.2 MW
Texas (ERCOT)	15,000 MW of wind	53 MW
California (CAISO)	6,700 MW of wind	Up to 230 MW

Source: Ela et al. 2011

One of the first U.S. studies to examine the impact of VG on frequency stability is the Western Wind and Solar Integration Study phase 3 (GE 2014). This study simulated the electric grid with more renewables in the western part of the United States. The study examined multiple scenarios of increased VG to determine whether a large contingency would lead to frequency collapse under various scenarios. The study found that, in simulations where VG was providing up to about 35% of the annual demand, the system operated normally in the case of a large power plant failure and was able to maintain enough primary frequency response to avoid under frequency load shedding where certain customers are dropped (blackouts) to restore the balance between supply and demand.[14] In some of the simulations, up to 64% of the total demand in any given moment in time was being met by VG. So, even when a large fraction of the demand was being met by VG, there was enough “residual” inertia and primary frequency response to prevent a blackout caused by under frequency load shedding.

Even as some large spinning generators retire, the existing generators still contribute to maintaining a stable frequency. To the extent that this generation is replaced with natural gas, those generators also help maintain stability in the traditional manner. However, many of these generators may be replaced with VG which is also capable of providing valuable “active power control” services for the grid (GE

[14] In this study the failure was the loss of two of the three units of the Palo Verde nuclear plant, a loss of about 2,750 MW.

2014, Gevorgian and O'Neill 2016). Active power control is sometimes used to describe the set of frequency stabilizing services including inertia, primary frequency response, and regulating reserves.

With sensors and controls that monitor grid frequency, VG generators can change output as needed to provide active power control. Wind turbines can draw stored energy from the rotor to help arrest a frequency decline or can be operated at reduced output during periods of high VG penetration to provide "synthetic" inertia and primary frequency response. For wind and solar to increase output and respond to a grid fault, they typically have to be operated at less than full capacity. At low levels of VG penetration, the power system typically has plenty of reserves available from other resources, so it does not make economic sense to provide these services from VG. However, at increased penetration, it may make sense to selectively curtail wind and solar to provide a variety of grid stability and reserve services.

Active power control from wind turbines is now available from many manufacturers and has been installed in the United States. For example, the Texas grid operator now requires wind generators to provide primary frequency response, which helps keep a system stable in the initial moments after a disturbance (Bird et al. 2014). In addition, FERC is also requesting comment on issues involving potential requirements for primary frequency response on new and existing generation and how compensation for such a requirement might work.[15] For the most part, active power control involves very little change to existing turbines (mostly software changes).

Provision of reserves from VG will require new mechanisms, whether market incentives or interconnection requirements or other means, to ensure that inverter-based wind and solar generators can meet the frequency response needs of the grid as they become a larger proportion of the generation fleet and displace traditional synchronous machines.

DEMAND-RESPONSE

DR can provide reserves and grid stability services. Several regions of the United States already derive a significant amount of operating reserves from DR. DR can provide active power control in the same way that generators can, by sensing frequency changes and decreasing load. Some regions, such as ERCOT, have programs where certain electricity consumers have loads that disconnect when they sense a drop in frequency, allowing them to provide a combined primary frequency response/contingency reserves service. The ERCOT grid now derives 50% of its contingency reserves from DR in the form of this "fast frequency response", which is the maximum currently allowed by ERCOT market rules (Potomac Economics 2014). The emergence of restructured markets [see text box "Load as a Resource"], new

Load as a Resource

Through a variety of demand response programs, load has increasingly become a resource for utilities and system operators. For example, the ERCOT (Texas) "Load Resource" program now allows the demand from large industrial customers to provide the exact same services as conventional generators, including being scheduled to vary demand and provide operating reserves (Potomac Economics 2014). For smaller consumers, aggregators act as a broker, combining the demand from many individual customers and allowing them collectively to sell market services by adjusting demand.

[15] See https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-3.pdf.

communication (smar0t grid) technologies, and rules allowing smaller entities to participate via the use of DR aggregation programs will likely increase the role of DR in providing reserves.

ENERGY STORAGE

Most forms of energy storage, including pumped storage, compressed air energy storage and batteries, can provide multiple reserve services, and storage often has greater ramp rates than conventional generators. Pumped storage and compressed air energy storage utilize synchronous generators that provide real inertia and can provide primary frequency response. Other types of storage including flywheels and batteries do not use synchronous generators but can provide synthetic inertia and primary frequency response in the same way it would be done with wind or solar. Storage devices such as flywheels and batteries have been installed specifically for the purpose of providing regulating reserves. The Western Wind and Solar Integration Study phase 3 (GE 2014) found that a relatively small amount of storage could provide significant grid stability benefits across the entire Western Interconnection.

TRANSMISSION

Transmission can reduce the variability of overall net load in any individual region by connecting regions together into larger areas, averaging out the changes in variable generation. Transmission also allows for greater spatial diversity of VG resources, and the associated “averaging” will tend to level out much of the very short term variability. This can lower regulating and contingency reserve requirements. Because it links more generators together in one power system, transmission increases the amount of system inertia. It also allows for greater sharing of all resources including primary frequency response.

OTHER TECHNOLOGIES

There are a number of technologies that can provide grid stability services when replacing traditional generators. One example is a synchronous condenser, which is a generator that has been “disconnected” from its turbine; this lets the generator spin freely and provide inertia and other grid services. Historically, synchronous condensers were used to provide voltage control (see the next section), but now system planners are considering them for additional applications, such as the provision of inertia. These devices can use the generators from decommissioned units or could be installed in new sites. One opportunity would involve installing clutches on new power plants so the generator could provide inertia even when the power plant is not running [see text box “Synchronous Condensers”].

Synchronous Condensers

Utilities in several locations have found it useful to re-purpose old power stations as “synchronous condensers.” When the old generator spins (powered by grid electricity), it acts as a giant flywheel and helps control and stabilize both voltage and frequency.

RULE 4: POWER SYSTEMS MUST BE ABLE TO MAINTAIN STEADY VOLTAGE AT VARIOUS POINTS ON THE GRID

WHY VOLTAGE STABILITY MATTERS

Ensuring electric system reliability requires maintaining both frequency (discussed in the previous section) and voltage. While frequency is constant throughout the grid, voltage varies depending on location. Figure 10 summarizes the voltage levels in different parts of the grid.

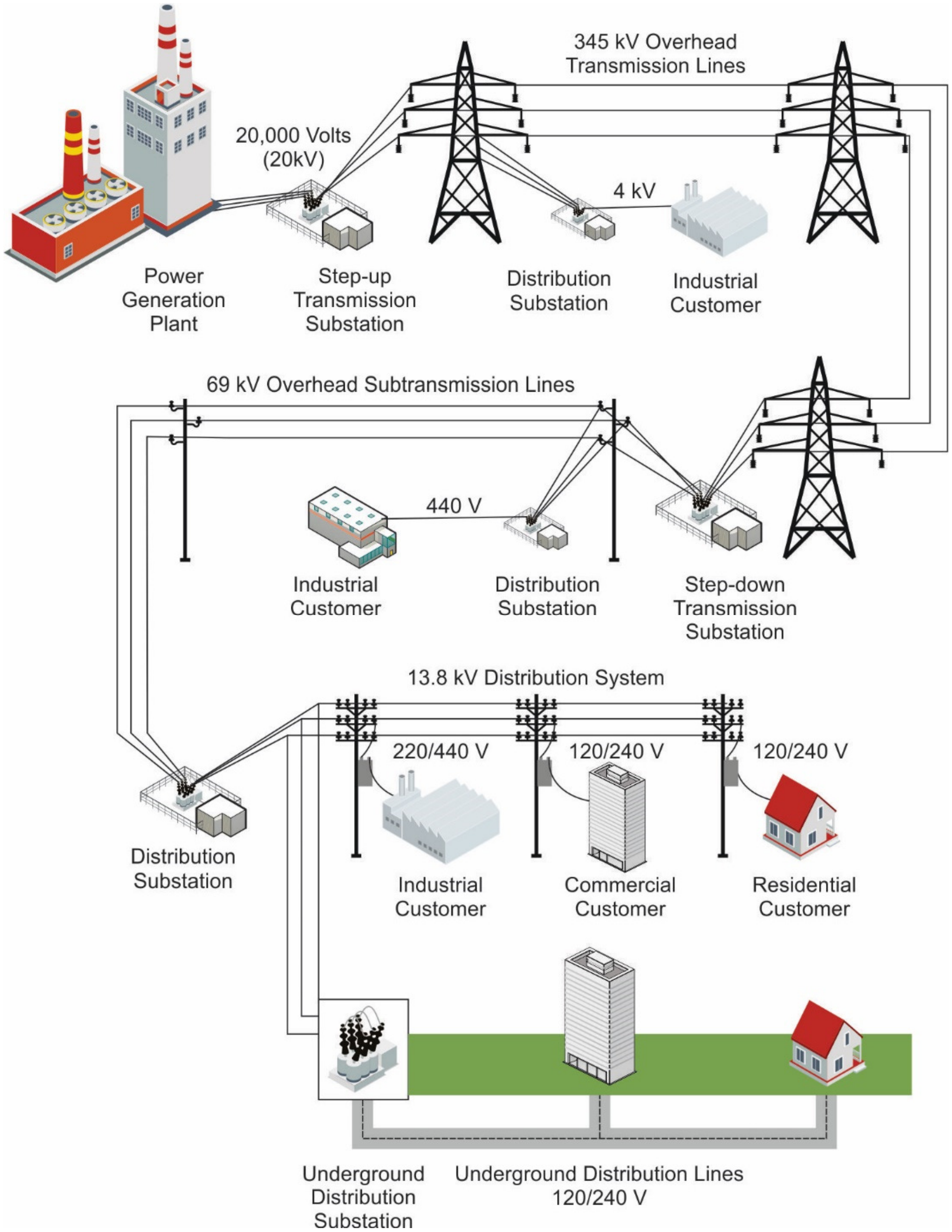

Figure 10. Power systems maintain voltage at different levels in different parts of the power system

In a sense, voltage in the electrical system is analogous to "pressure" in a fluid system, and each part of the grid is designed to work at a specific voltage level. Voltage that is too high or too low can result in malfunction or damage to electrical devices. To provide reliable service, power system operators continuously adjust voltage at various points on the grid to keep voltage stable or within a certain tolerance. As with frequency decay, voltage collapse is possible when there is insufficient voltage control to maintain steady voltage after an equipment failure on the grid.[16] Devices that provide voltage control maintain appropriate voltage on the grid during both normal operating conditions and fault conditions.

COMPLYING WITH RULE 4: TRADITIONAL MEANS

Power system operators use a variety of electrical devices to maintain voltage throughout the grid. Conventional generators typically produce about 10,000-25,000 volts (Figure 9), which is "stepped-up" to as much as 765,000 volts for transmission. The higher voltage results in lower losses allowing energy to be efficiently transmitted over long distances. To deliver electricity to homes and businesses, voltage is then "stepped-down" as electricity moves to the distribution network, and then stepped-down again—typically to about 240 or 120 volts—for residential and commercial customers. Changes in voltage between different parts of the transmission and distribution system are accomplished via transformers.

Voltage is controlled by different methods at different points of the grid. A key element of controlling voltage at each point on the grid is the ability to inject or absorb reactive power. Reactive power is a property of AC electrical current that is needed to maintain the flow of power. Too much or too little reactive power can reduce the flow of power and result in inadequate voltage. Reactive power cannot be transmitted over long distances.[17] Therefore, voltage control is performed at each of the three major parts of the grid:

- At the point of generation, by monitoring local voltage levels and adjusting the spinning synchronous generator's reactive power output to maintain voltage at a specified level.
- In the transmission network, using electrical devices including shunt capacitors (to supply reactive power and increase voltage), shunt reactors (to absorb reactive power and lower voltage), electro-mechanical devices such as load tap changing transformers (to increase or decrease the how much a transformer steps up or steps down voltage) and power electronic equipment that actively injects or absorbs reactive power.
- At the distribution network, using similar types of devices as on the transmission network to provide local voltage control.

[16] An example of an event caused by voltage collapse was the 2003 East Coast blackout. See U.S.-Canada Power System Outage Task Force. 2004.

[17] For additional discussion of reactive power, see FERC 2005. Principles for Efficient and Reliable Reactive Power Supply and Consumption at http://www.ferc.gov/CalendarFiles/20050310144430-02-04-05-reactive-power.pdf.

COMPLYING WITH RULE 4: NEW OPTIONS

Today, new technologies based on power electronics supplement the traditional voltage control tools listed above. Power electronics can quickly and efficiently absorb or generate reactive power. Typically, power electronics are inexpensive and are built into inverters used by VG or energy storage devices or installed as stand-alone devices.

VARIABLE GENERATION

The power electronics built into wind turbines and PV inverters are well-suited to providing voltage control and reactive power. In 2016, FERC issued order 827 requiring VG units over 20 MW to provide reactive power (FERC 2016), and even before this utilities and system operators were increasingly requiring VG units to provide voltage control (Milligan et al. 2015). Using the power electronics that already exist in VG resources to control voltage often involves little more than software changes.

ENERGY STORAGE

Pumped storage and compressed air energy storage utilize synchronous generators that can provide voltage control in the same manner as conventional generators. However, many other types of storage, including flywheels and batteries, use power electronics to generate 60 Hz AC power. The use of power electronics allows energy storage devices to easily provide local voltage control similar in manner to VG devices.

OTHER STAND-ALONE POWER ELECTRONIC DEVICES

Power system operators also have new tools to control voltage at the transmission level in the event of a grid disturbance. Commonly grouped under the term Flexible AC Transmission Systems (FACTS), these power electronics-based devices can provide fast voltage control in response to grid disturbances.[18] While FACTS devices have existed for decades (Hingorani and Gyugyi 1999), decreasing costs and new technologies provide utilities with new options. These devices are typically scalable, so they can be installed relatively quickly in the right size to perform the necessary job, which can reduce or defer the need to build transmission lines or large power plants. FACTS can typically be located close to areas of potential concern. Overall, modern power electronics can solve many voltage control problems that historically would have required larger and more costly generators, transmission lines or electro-mechanical devices.

OTHER TECHNOLOGIES

Beyond these new technologies, as old generators are retired, some areas of the grid may have insufficient local reactive power to maintain voltage stability. In these cases, the retired generator is sometimes put to a new use as a stand-alone synchronous condenser to provide local reactive power.

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[18] They include static var compensators, static synchronous compensators, thyristor controlled phase shifting transformers, unified power flow controllers, and thyristor controlled series compensation. See CIGRE, "Overview of Flexible AC Transmission Systems, FACTS". http://b4.cigre.org/content/download/1973/25265/version/2/file/FACTS+overview_Cigr%C3%A9+B4_What+is+FACTSID10VER39.pdf.

CONCLUSION

In the United States, the reliable power system underpins our economy and quality of life. That reliability has been designed into our system. Historically, power system operators have had a limited set of tools at their disposal to balance power supply and demand and maintain proper frequency and voltage at all times, but these tools—primarily large spinning generators in addition to specialized equipment used to maintain voltage—have worked very well. Today, power systems are evolving, and many of those generators are retiring. However, at the same time, the evolution of the power system has provided a new toolbox for maintaining reliability. As more variable generation is built, it can be used to maintain reliability in ways similar to the generation it is replacing, and new, more affordable power electronics create new opportunities for DR programs and other tools for balancing supply and demand. With this new toolbox and continued careful planning, coordination, and investment, reliability can remain a trademark characteristic of our evolving power system.

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