1 Introduction

Globally, power systems are integrating increasing levels of variable renewable energy (VRE) resources, particularly solar and wind energy, in the electric power mix. Several jurisdictions have achieved yearly VRE penetrations above 20% (e.g., California and Denmark) and maximum instantaneous penetration well above 50% (e.g., Texas and Ireland). Because VRE generation is variable (i.e., energy generation changes based on the availability of the underlying wind and solar resource) and uncertain (i.e., the magnitude and timing cannot be predicted with perfect accuracy), power systems with increasing shares of VRE require more flexibility to balance electricity supply and demand at all timescales. Many studies have demonstrated the value of different strategies to improve power system flexibility, including balancing area coordination, faster resource scheduling and dispatch, advanced solar and wind power forecasting, and improved conventional power plant flexibility (IEA 2017, Cochran et al. 2014). This report focuses on flexibility from the side of VRE generators themselves, namely through solar and wind generator participation in automatic generation control (AGC) for the provision of essential reliability services.

One measure of power grid reliability is the stability of a system's frequency at a desired level. If a large load (such as a water pump) disconnects from the grid, frequency will increase with greater supply than demand. Conversely, if a large generator trips offline, frequency will decrease, requiring an increase in supply from other sources on the grid. If frequency falls below a threshold, emergency load shedding may be activated to prevent damage to equipment. To maintain frequency, system operators use essential reliability services, which comprise the collection of services necessary to support the transmission of energy and maintain reliable operation of the transmission system. Traditionally, fossil-fueled generators are the primary providers of these services. However, as VRE generation increases, it is important to consider how these generators can contribute to power system reliability. This report provides an update on how VRE generators contribute to power system reliability through participation in AGC systems.

AGC systems enable a grid operator to centrally and automatically manage the output of interconnected generators, storage devices, and controllable loads to maintain system frequency and inter-area transmission flow schedules. Without AGC, grid operators must rely on manual communications and controls with individual generators to provide essential reliability services. This report focuses on technological and regulatory considerations of using VRE generators to provide a specific type of essential reliability service: secondary frequency control or frequency regulation. Other types of essential reliability services that solar and wind generators can provide, including inertial response, voltage regulation, and dynamic volt-ampere reactive (VAR) support, are outside the report's scope.

Section 1 provides a brief overview of AGC. Section 2 reviews current experiences of solar and wind generators on AGC. Section 3 describes market rules, regulations, and contractual mechanisms for enabling solar and wind generators to participate in AGC systems. Section 4 reviews metering and communications equipment necessary to integrate solar and wind power plants with AGC systems. Section 5 concludes with a discussion of key messages and takeaways.

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2 Overview of Automatic Generation Control Systems

AGC is a system of operational procedures and equipment that provides for automatically adjusting generation within a balancing area from a centralized location. AGC is used in continuous operations, as well as during grid disturbances, such as a transmission line fault or the sudden loss of a large generator.

For continuous operations in large interconnected power systems, such as North America and Continental Europe, balancing areas use centralized AGC systems to continuously (every 4-6 seconds) update the setpoints of generation resources to minimize the area's area control error (ACE). The ACE is a measure of imbalances in the area's scheduled transmission flows and grid frequency.[1] In some island systems (e.g., Hawaii and Puerto Rico), the AGC system updates the power setpoints for participating generators every two seconds. The continuous updating of generation setpoints to minimize ACE is typically referred to as frequency restoration, frequency regulation, or regulation. Figure 1 illustrates regulation service provided by the AGC system in the Electricity Reliability Council of Texas (ERCOT) interconnection. RegD is the regulation product in the ERCOT real-time market. When the ACE is trending up, the RegD signal increases generator output and reduces participating loads; when the ACE trends down, generator output is increased and loads are reduced to help restore ACE to zero.[2]

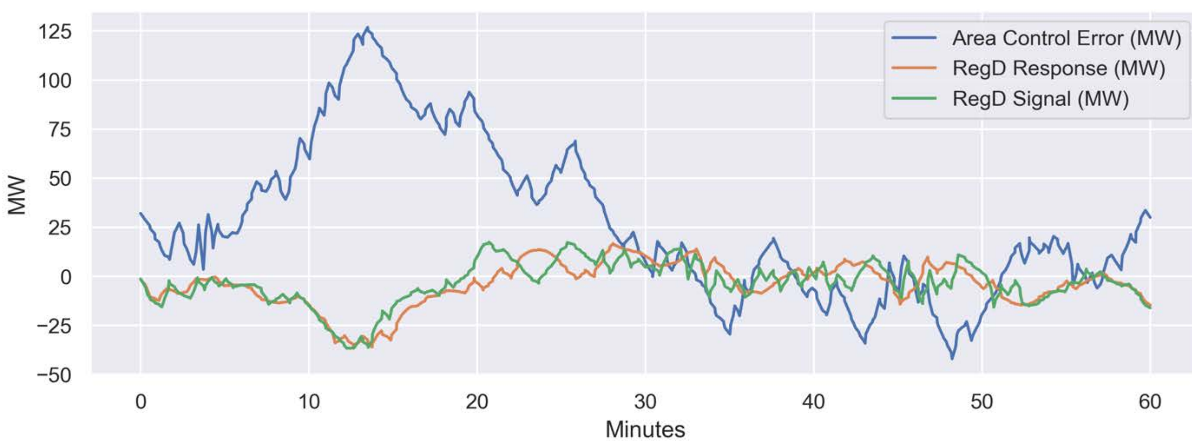

Figure 1. Using a regulation signal to correct the ACE in ERCOT

Figure adapted from Kirby et al. 2010

Another function of AGC systems is returning frequency to the nominal level following a grid disturbance, such as a sudden loss of a large generator, load, or transmission line. For example, if a large generator trips offline, mechanical generators already online or electronic generators that can react immediately (i.e., solar PV or battery storage) can increase their output to arrest the falling system frequency. This initial reaction of the grid is known as primary frequency response. Once the system frequency is stabilized and no longer cascading downward, new generation can come online to bring the system frequency back to the nominal level. This frequency restoration service (also known as secondary

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[1] The goal of a balancing area authority in an interconnected system is to keep the ACE close to zero. See Ela, Milligan, and Kirby (2011) for a comprehensive review of ancillary services, including a detailed description of ACE.

[2] Other frequency restoration services not shown in Figure 1, including inertia and governor response, act in concert with AGC regulation signals to restore ACE to the nominal level.

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frequency control or secondary reserves) is provided by resources on the AGC system as depicted in Figure 2.

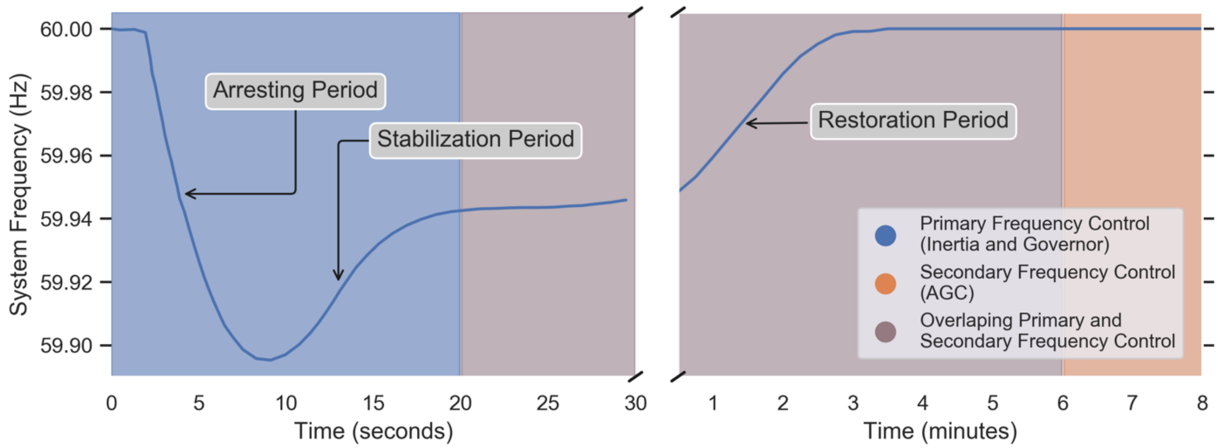

Figure 2. Primary and secondary frequency responses following a contingency event

Figure adapted from Eto et al. 2010

AGC functionality of conventional generators (also called secondary frequency control) is a supplementary control added to the turbine governing system. In interconnected power systems, regulation is implemented by changing the power output of turbines in the area through varying the power setpoints of their governing systems. Accurately estimating ACE at each AGC time step is essential for successfully implementing AGC. For a balancing authority, area ACE is determined as follows:

$$ACE = -\Delta P_{tie} - 10B(f_m - f_s) + E_{ME} + E_T \quad (1)$$

Where ΔP_{tie} is the net tie-line interchange error; B is the frequency bias measured in MW/0.1Hz; f_m and f_s are the measured and scheduled frequencies; and E_{ME} and E_T are the meter error correction and time error correction factors respectively in MW.

To avoid confusion with frequency response, we have defined frequency bias *B*, even though some similarities exist between the terms. Frequency response β, as defined by the North American Electric Reliability Council (NERC), is the mathematical expression of the net change in a balancing area (BA) net actual interchange for a given change in interconnection frequency. Frequency response β represents the actual, physical megawatt-primary response contribution from participating units to stabilize frequency after system contingency events. Frequency bias *B* approximates frequency response β and is calculated from actual historic operations in a BA (NERC 2011). The inclusion of the bias variable in the ACE calculation helps to prevent immature AGC withdrawal after a disturbance. Both B and β are negative and measured in MW/0.1 Hz.

The value of *B* must be set to ensure adequate AGC performance. The NERC resources subcommittees maintain the list of frequency excursion events used for annual bias calculations. Guidelines in selecting and evaluating events for bias calculations include:

- Evaluate the frequency bias for a given BA, avoid events that result in contingency events within the same BA or its immediate neighbors, as such events are typically accompanied by large swings in tie-line power flows

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- Use frequency events scattered through the whole year of observation to ensure "average" bias is adequate for many load and dispatch scenarios

- Use frequency events large enough to exceed the governor dead bands.

Typically, f_s is set to nominal frequencies of 50 or 60 Hz; however, in some cases f_s can be set to different values for the purposes of modified ACE measurements, like during time error corrections. Time error correction is used by some system operators to restore the mean frequency back to its nominal value so the accumulated time error can be driven to zero. Some system operators specify the maximum allowed accumulated time error. For example, the Australian Energy Market Operator specifies the maximum time error for the National Electricity Market (NEM) Mainland region at 5 seconds, and for Tasmania at 15 seconds (AEMO 2012). The accumulated time error ε_t can be calculated by comparing the measured frequency with the nominal frequency in the respective time period T:

$$\varepsilon_t = \int_0^T \frac{f(t) - f_{nom}}{f_{nom}} dt \quad (2)$$

Where $f(t)$ and f_{nom} are measured and nominal system frequency, respectively. For example, if $f(t) > f_{nom}$, then the time error ε_t will be positive. This means grid frequency-based clocks will run faster. Error ε_t is corrected by modifying ACE in the control areas.

The AGC setpoints for all participating generators in the control area i can then be calculated by a controller with a proportional-integral (PI) characteristic based on the following equation:

$$\Delta P_{gen,i} = -(K_{P,i} \cdot ACE_i + \frac{1}{T_{I,i}} \int ACE_i dt) \quad (3)$$

Where $K_{P,i}$ and $T_{I,i}$ are proportional and integral gains of the AGC controller of the area i. The output value of the PI controller is used to determine the total desired generation that will drive ACE to zero. PI controllers of AGC systems are tuned for each system and depend on many variables, including system size and response characteristics of generating units dispatched for frequency regulation. The desired generation setpoint for each participating generating unit is split into two components: the base point and regulation. The base point for each generating unit is set at its economic dispatch point, and the system's total regulation is calculated as the difference between the total desired generation and the sum of the base points for AGC participating units. Various unit-specific parameters are used to determine a unit's regulation allocation, such as ramp rates and operating limits.

Many vendors provide turnkey power system supervisory control and data acquisition (SCADA) solutions with embedded AGC functionality. AGC software is normally integrated with economic dispatch and interchange scheduling, ensuring generation adjustments are conducted in the most economical way. AGC software also calculates parameters required for load-frequency control and provides setpoints to all participating units to maintain system frequency and power interchange schedules with neighboring systems, in accordance with AGC performance metrics for a given power system. The AGC controller parameters can be optimized and tuned accordingly to ensure adequate performance. In general, the management of AGC systems presents a challenge for system operators worldwide due to the increasing sizes and complexities of interconnected multi-area power systems, evolving mixes of conventional and variable generation, and coexistence of AC and DC transmission technologies.

Figure 3 shows a typical diagram of an AGC system; the ACE signal is first filtered by low-pass and PI filters with consecutive processing by the AGC distribution module. This process generates the ramp-

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limited AGC setpoints for the individual units based on their participation factor, dispatch status, available headroom, and other physical characteristics.

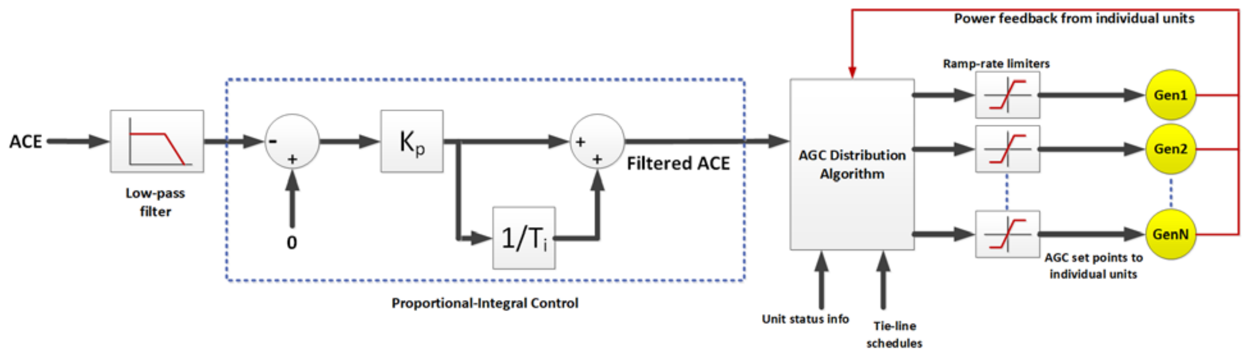

Figure 3. Diagram of typical AGC system

AGC systems operate with SCADA systems. SCADA gathers information on system frequency, generator outputs, and actual interchange between the system and adjacent systems. Using system frequency and net actual interchange, plus knowledge of net-scheduled interchange, an AGC system determines the system's energy-balancing needs with its interconnection in near real time.

In the United States, the degree of AGC's success in complying with balancing and frequency control is historically manifested in a balancing authority's control performance compliance statistics and metrics, as defined by NERC's control performance standards (CPS). CPS1 is a measure of a balancing authority's long-term frequency performance with the control objective of keeping frequency excursions within an average of one-minute frequency error during 12 months in the interconnection. CPS1 allows for evaluating how well a balancing authority's ACE performs with the frequency error of the whole interconnection. CPS2 is a measure of a balancing authority's ACE during all 10-minute periods in a month with the control objective to limit ACE variations and bound unscheduled power flows among balancing authority areas.

In recent years, NERC's BAL-001-2 Real Power Balancing Control Standard has defined the Balancing Authority ACE Limit (BAAL), replacing CPS2. BAAL is unique for each balancing authority and provides dynamic limits for ACE values as a function of interconnection frequency. The objective of BAAL is to maintain the interconnection frequency within predefined limits. A field trial of BAAL began in the U.S. Eastern Interconnection in July 2005 and in the Western Interconnection in March 2010. Enforcement of BAAL began on July 1, 2016. Both CPS1 and BAAL scores are important metrics for understanding the impacts of variable renewable generation on system frequency performance. NERC's reliability standards require that a balancing authority balances its resources and demand in real time such that the one-minute average of its ACE does not exceed its BAAL for more than 30 consecutive minutes.

Figure 4 shows a distribution of recorded ACE (every four seconds) during a spring month for one balancing authority in the United States. This balancing authority had many occurrences of over 50% instantaneous wind power penetration during the period of ACE recording. The AGC system could maintain the ACE within BAAL limits during 99% of recorded periods.

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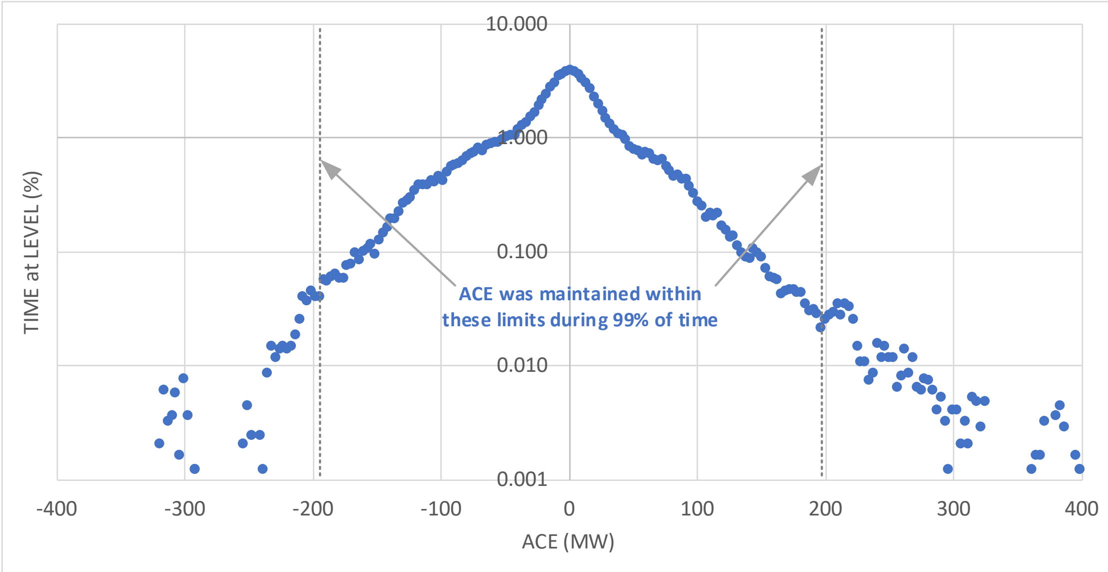

Figure 4. ACE distribution for one spring month

2.1 AGC Capabilities of Solar and Wind Power Generators

Several studies have demonstrated the technical capability of VRE generators to provide essential reliability services, also known as ancillary services, through AGC (Loutan et al. 2017; Ela et al. 2014; Aho et al 2015). Other studies have assessed the economic merits of VRE generators, particularly wind power plants, for providing regulation and frequency response reserves (Kirby et al. 2010).

A VRE generator can provide regulation up service by maintaining headroom between its output and its maximum potential generation at a given time. Based on weather forecasts and prices for energy and ancillary services, among other considerations, a generator can determine its optimal headroom. For example, a 300-MW solar power plant could, based on forecasted availability, offer 30 MW to a regulation up market and 270 MW to an energy market. During normal system operation, the plant self-curtails to limit output to 270 MW, but can immediately provide up to 30 MW through the regulation up ancillary service, based on signals from the system operator. Solar and wind plants can also provide regulation down, which curtails the plant's output based on AGC signals.

For solar generators, power curtailment is performed at the inverter without any mechanical interaction. Demonstration projects of active power control by utility-scale solar PV power plants have demonstrated that the regulation up accuracy (i.e., the accuracy of active power response to a regulation up signal) of a solar plant ranges 87-94%, depending on time of day and solar resource conditions. This range is significantly higher than the regulation accuracy of a typical thermal-, hydro-, or battery-storage generator (Loutan et al 2017; Gevorgian and O'Neill 2016). Wind turbines actively control power output, using power electronics to actuate the torque on the generator shaft and changing the pitch angle of the blades relative to the wind direction, which changes the rotational speed of the rotor. Actively reducing output from wind turbines has not been found to cause excessive wear from loading impacts (Aho et al 2014).

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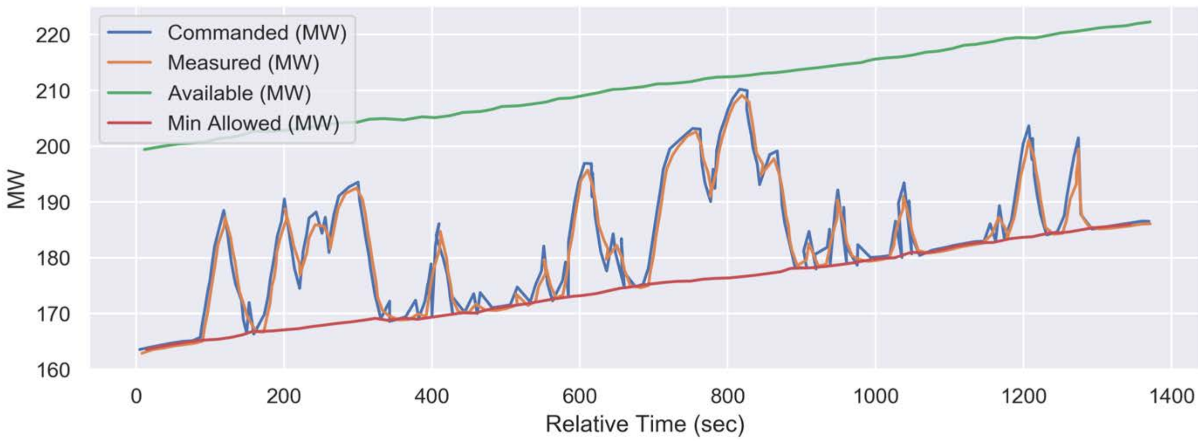

Figure 5. Solar power plant providing AGC frequency regulation service

Figure adapted from Loutan et al 2017

Because VRE generators have near-zero MWh production costs, the decision to provide headroom or curtail output for frequency regulation is typically based on the price of an ancillary services product relative to the lost revenue from energy production. Particularly when the value of energy is low or negative (e.g., during periods of overgeneration), it could be cost-optimal for the VRE generator to curtail energy output in favor of providing frequency regulation. Regulation down services are generally considered more accessible for VRE generators because they only require the instantaneous curtailment of an amount of energy dictated by the AGC signal. If the payment for reducing output is more than the price of the energy that would otherwise be provided, it can be economic for VRE plants to provide regulation down service. Because regulation up services require constantly available headroom, it is less likely for VRE resources to participate in these markets because this would require them to incur significant levels of curtailment.

To provide active power reserves (or a headroom margin) for up-regulation that can be automatically dispatched as needed, solar and wind power plants must operate below their maximum power point (MPP); however, evaluating the MPP in curtailed mode is not a trivial task, especially for large solar PV power plants during variable conditions caused by clouds. For utility-scale PV power plants to maintain the desired regulation range or spinning reserve levels, the plant controller must be able to estimate the available aggregate peak power that all the plant's inverters can produce at any point. The available power is normally estimated by an algorithm that considers solar irradiation, PV modules' I-V characteristics and temperatures, inverter efficiencies, and other physical parameters; however, this method has uncertainties, depends on the availability of accurate system models, and does not account for other factors, such as panel soiling from dust. A new method was recently introduced by NREL, allowing accurate estimation of available active power headroom in curtailed utility-scale power plants under extreme solar resource variability conditions caused by cloud movements (Gevorgian 2019). The proposed technique does not require deploying any additional equipment or sensors and is based only on the addition of new control logic to the existing power plant controller (PPC). Also, the proposed method is universally applicable to PV plants with any type of smart inverters and PV modules.

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3 Metering, Communications and Control Equipment Needed for VRE to Participate in AGC Systems

For solar and wind plants to provide ancillary services through AGC, they must have the equipment needed to perform all necessary communications and control functions.[3] A key piece of equipment is the PPC. A PPC is a central control unit that serves as the interface between the system operator and the solar or wind power plant. It continuously monitors plant-level performance, sends real-time commands to plant inverters, and manages the operation of various plant devices to achieve fast and reliable adjustments. A standard PPC can provide:

- Remote manual control of inverters (e.g., individual, blocks of inverters, or whole plant control)
- Active power curtailment, generation restoration after failure, and frequency control validation
- Automatic voltage regulation
- Power factor control
- Voltage limit control
- VAR control.

More-advanced PPC systems can interface with AGC systems to provide secondary reserves. Other advanced PPC capabilities that have been demonstrated and field-tested include primary frequency response with various droop settings, ramp rate control, and voltage control at near-zero active power levels.

One example of PV plant communication architecture developed by AES Corporation and NREL, which was deployed on a 20 MW AES Ilumina PV power plant in Puerto Rico, is shown in Figure 6 (Gevorgian and O'Neill 2016). This system was linked to Puerto Rico Electric Power Authority's (PREPA) control center and was used to conduct demonstration tests for PV participation in AGC. Issues that needed to be addressed in the Ilumina demonstration project included communications protocol compatibility and proper scaling for setpoint signals. In this case (Figure 6), the remote terminal unit (RTU) and GPM SmartBridge controller were used to link the PV plant controller with the system operator's control center. Modifying programming logic may be necessary at multiple places in the chain of communications when enabling AGC capabilities in existing solar or wind generation plants.

[3] A detailed review of communications, control, and cybersecurity standards for AGC systems is outside the scope of this report. Additional information for U.S. standards can be found at the NERC web portal for Reliability and Security Guidelines (https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx).

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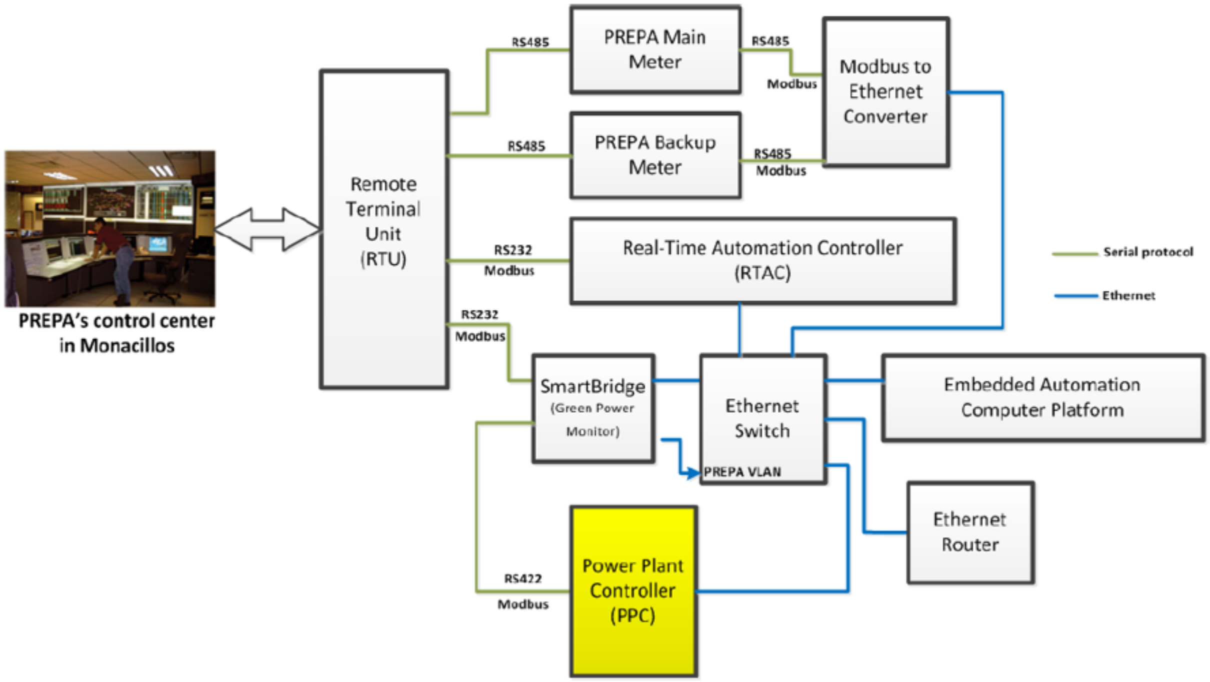

Figure 6. Example of AES Ilumina PV plant's RTU communications architecture

Image from Gevorgian and O'Neill, 2016

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4 Experiences of Solar and Wind Generators on AGC

Only a handful of jurisdictions currently use VRE generation on AGC. These experiences, as well as recent developments that may enable VRE to participate in AGC soon, are described in this section.

4.1 Jurisdictions Using VRE Generation on AGC

4.1.1 Public Service Company of Colorado

Xcel Energy is a utility company serving more than 3.6 million electricity customers and operating in eight states across the United States. In the state of Colorado, Xcel Energy owns and operates the Public Service Company of Colorado (PSCo), a vertically integrated utility responsible for electricity generation, transmission, distribution, and retail sales. In 2016, wind power accounted for 24% of electricity generation in PSCo (Xcel Energy 2016). All system operators in the United States, Canada, and parts of Mexico are required to meet reliability standards established by NERC (NERC 2016). One of the mechanisms by which PSCo maintains reliable system operations under increasing VRE penetration is by integrating wind plants into the system operator's AGC system.

PSCo is currently the only balancing authority in the United States known to require all wind power plants to install AGC equipment. This requirement is codified in PSCo's model energy purchase agreement (commonly known as a Power Purchase Agreement [PPA]), which also includes general facility design, project implementation considerations, metering and telemetry requirements, electricity sale and purchase obligations, and other standard contract terms (Xcel Energy 2017).

Though PSCo's fleet of wind plants routinely provide regulation down via AGC, based on contract considerations, system operators have expressed a reluctance to rely on wind generation forecasts to guarantee up regulation (Ratcliff 2018). PSCo operates under the assumption that VRE resources may be unavailable, and therefore relies on thermal generators for up regulation. A diverse mix of VRE resource types and locations can mitigate some variability, and detailed forecasts and experiences are credited with helping PSCo system dispatchers anticipate when wind generation will likely experience a significant change in output. When wind is available, PSCo operators commended its ability to react nearly instantaneously and accurately to AGC signals (Ratcliff 2018).

4.1.2 Wind Power Plants Qualify for Ancillary Services Provision in ERCOT

The Electric Reliability Council of Texas (ERCOT), the independent system operator and wholesale market administrator in the state of Texas, serves 24 million electricity customers. In 2018, wind accounted for 18.6% of generation, and solar <1% (ERCOT 2019). All qualified generation resources can participate in the day-ahead markets for both energy and ancillary services. For ancillary services, qualified generators can submit bids in the day-ahead market for provision of regulation (normal operations), primary frequency response (for contingencies, called Responsive Reserve Service in ERCOT), and non-spinning reserves. The ERCOT market splits the hourly regulation requirement into two separately purchased regulation up and regulation down products. The day-ahead market is co-optimized for energy and ancillary services, meaning markets clear simultaneously to select a cost optimal suite of resources for both energy and ancillary services. Co-optimization involves running a computer simulation (i.e., the Security Constrained Economic Dispatch model) to determine prices for energy and ancillary services in the day-ahead market. A co-optimized market helps ensure adequate resources exist to supply both energy and ancillary in the most cost-effective manner.

Like most wholesale energy markets, the market clearing price (MCP) in ERCOT is a singular price paid to all accepted generators (those that bid into the market at or below the MCP) in the day-ahead market. The MCP is determined by the intersection of a demand curve and a supply curve representing all bids. In times of scarcity, the MCP can rise drastically (up to thousands of dollars per MWh), leading to a high

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MCP paid to all accepted generators. Because the volume of energy procured by system operators is large, relative to the volume of other products, mature energy markets do not experience scarcity under normal operation. Ancillary service markets are smaller in volume and require a degree of flexibility from generators that is sometimes unavailable. For VRE generators, the cost of providing ancillary services is equal to the opportunity cost of not providing energy; this involves a tradeoff between opportunity for profit and risk of losing energy-only revenues.

Throughout 2017 in ERCOT's wind-heavy West Load Zone, the day-ahead price of regulation down service surpassed that of energy for 806 hours (9.2% of hours), the day-ahead price of regulation up service surpassed energy for 515 hours (5.8% of hours), and the combined price for day-ahead regulation service was higher than the cost of energy for 1,438 hours (16.4% of hours). Most of these instances occurred during the night (10 p.m.–12 a.m.) and morning (5 a.m.–7 a.m.). Figure 7 displays the 2017 average price of these services on an hourly basis (ERCOT 2017). Prior research found that in both ERCOT and California Independent System Operator (CAISO) territory, it is more lucrative for wind to offer regulation services during the night, because thermal generators are already operating close to their minimum generation level and cannot provide regulation down service. Furthermore, resource availability of wind is higher at night in some regions (Kirby et al. 2010); however, only a handful of wind generators have opted to qualify for the ancillary services provision in ERCOT, and their participation in regulation markets is currently minimal (Matevosjana 2018).

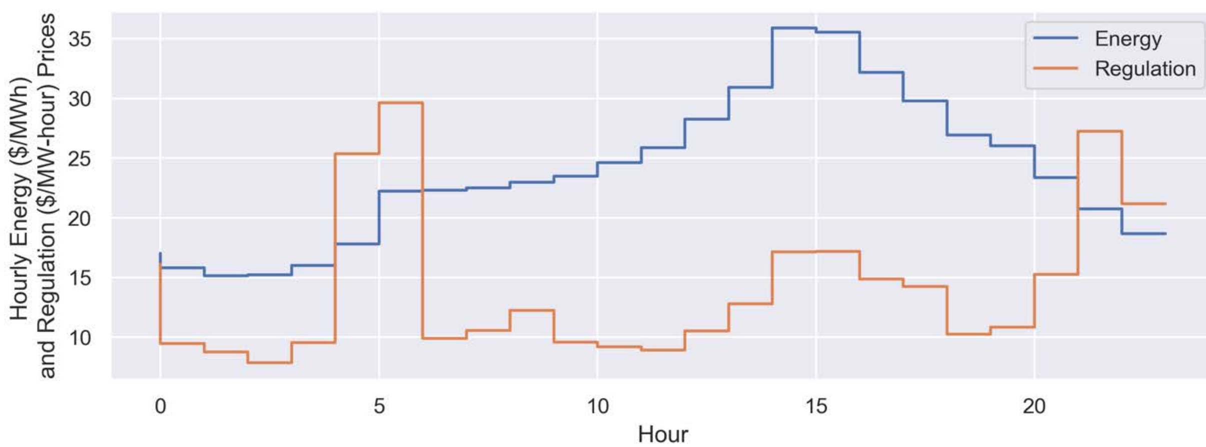

Figure 7. 2017 hourly average price of energy and regulation in ERCOT's West Texas Load Zone

Figure based on Kirby et al. 2010, updated with 2017 wind data provided by ERCOT

4.1.3 ENTSO-E Practices for Frequency Regulation

The European Network of Transmission System Operators for Electricity (ENTSO-E) is made up of 43 transmission system operators (TSOs) that serve as the balancing authorities for 36 countries in the European Union and across the European continent. ENTSO-E provides governance of TSOs to meet network grid codes established by the European Commission. To balance frequency, TSOs fall within Load Frequency Controller (LFC) blocks. Most LFC blocks are composed of a single country or a small group of countries.

LFC blocks can use AGC signals, manual frequency restoration reserves, and replacement reserves to regulate frequency. Western and Central European LFC blocks, like those in Belgium, Germany, Austria, Slovakia, and Hungary, use AGC most often (over 80% of the time) in balancing frequency. The Nordic LFC Block uses AGC least often (less than 20% of the time). Blocks like France and Spain use AGC

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around 50% of the time and employ manual methods or reserves the rest of the time (ENTSO-E 2016b). Each LFC block calculates their ACE with the synchronous system and uses this value to establish frequency setpoints for generators providing frequency services in their territory.

LFC blocks differ in how frequency reserves are dispatched. Some use a *pro-rata* method, whereby generators bid into day-ahead or advanced-frequency regulation markets, and the requisite capacity to respond to an event is distributed between all accepted generators. Others use a merit-order activation scheme, whereby a day-ahead or real-time market determines the least-cost mix of generators to provide frequency regulation service (ENTSO-E 2016a).

Another distinguishing factor among LFC blocks is how participating resources are instructed to ramp toward setpoints. Some provide generators with a "stepwise" AGC signal that contains a target setpoint and time. The generator must be generating at that capacity by the given time. The setpoint is designed to be achievable by the generator at a linear ramp rate. Other LFC blocks use continuous ramping schedules, which provide generators with a trending setpoint every 4–10 seconds, considering each resource's ramp rate. This protocol requires that generators connected through inverters (e.g., wind and solar) have their inverters programmed to meet the specific ramping requirements.

All LFC blocks allow VRE generators to provide frequency regulation service and participate in the AGC control system, although as of 2015 ENTSO-E was not aware of any wind or solar plants providing these services. ENTSO-E acknowledges that avoiding curtailment is the likely reason for this absence (ENTSO-E 2016b). A new initiative—Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation (PICASSO)—could provide additional incentive for the participation of variable generators. PICASSO aims to move away from regional LFC blocks and toward a single frequency regulation area (ENSTO-E 2016b). One challenge to integrating the LFC blocks is the large range in response times of different resource types. For example, thermal resources provide the majority of AGC capacity in Belgium, the Netherlands, and Denmark, despite substantial wind and solar capacity. Some of these thermal resources can take 15 minutes or longer to fully ramp up to their maximum AGC capacity. In contrast, electronically interconnected generators, such as wind and solar generators, provide this response almost immediately, assuming resource availability. Integration of a single AGC system across TSOs will require a standardized prerequisite response time.

4.2 Enabling Elements for Solar and Wind Generators to Participate in AGC systems

This section reviews regulations and market design elements that can enable solar and wind generators to contribute to grid reliability by participating in AGC systems.

4.2.1 Regulations

Enabling and Incentivizing VRE Participation in Frequency Regulation Services (FERC Orders 755, 784, and 842)

Federal Electricity Regulatory Commission (FERC) Order 755 is one example of a regulatory directive that can improve the participation of nontraditional energy resources, such as solar and wind, in ancillary services markets. Order 755 directed wholesale market operators in the United States to implement performance-based compensation for provision of frequency regulation services. Under performance-based compensation, rather than a simple capacity-based payment, generators are compensated based on the actual measured response (i.e., regulation mileage) recorded for frequency regulation. Resources that can respond faster and more accurately to AGC signals are then able to capture more revenue than they are under the traditional capacity-based compensation scheme. This incentivizes solar and wind

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generators to provide regulation because they can respond to AGC signals faster and more accurately than conventional generation.

FERC Order 784 is a related order that requires utilities to consider the speed and precision of response when choosing among different sources for ancillary services and directs wholesale market operators to ease barriers for third-party provision of ancillary services. Order 784 remains technology-neutral and states that its intent is to "enhance competition and transparency in ancillary service markets" (FERC 2013). The resource qualification process used in ERCOT similarly demonstrates a commitment to standardized response requirements across all technology types.

FERC is addressing other frequency restoration and response issues through Order 842, which requires all newly interconnected generators to install, maintain, and operate equipment capable of providing primary frequency response (FERC 2018). ERCOT, which is not under FERC jurisdiction, also requires all new solar and wind generators to have primary frequency response capabilities (Matevosjana 2018). Though this requirement addresses primary, not secondary, frequency response (and may not, for example, address telemetry equipment that would be needed for AGC), this regulation would ensure VRE generators interconnect with advanced inverters, which can be programmed to provide secondary frequency reserves.

Clearly Defined and Enforced Grid Codes for Solar and Wind Generator Performance and Capabilities

Grid codes and standards are the rules and regulations that dictate the performance of grid-connected energy resources. Utilities rely on grid codes to ensure electric grids will remain safe and reliable as new generators are interconnected. Grid codes typically contain various provisions for how grid-connected resources should behave during normal operations and during grid disturbances, including provisions for voltage control, active and reactive power management, communications, and islanding behavior, among others. To date, most grid codes for solar and wind generators have focused on distributed energy resources (DERs) connected to distribution-level (medium- and low-voltage) grids. Examples of widely applied distribution-level grid codes include IEEE standard 1547 in the United States, as well as BDEW and VDE 4105 in Germany. Efforts are currently underway to develop codes and standards specifically designed for solar and wind generators connected to high-voltage transmission.

4.2.2 Market Design

Ancillary services provision from solar and wind generators is an emerging practice in markets with increasing penetrations of VRE. In general, jurisdictions that are enabling VRE to participate in AGC systems follow a common set of objectives for the rulemaking, regulation, and design of ancillary services markets:

Competitive. Market designs that enable fair competition among ancillary service providers can help ensure efficient procurement and effective delivery of AGC services.

Technology neutral. Rules for market participation focus on capabilities, rather than technology-specific attributes.

Merit order. Merit order is a method for scheduling resources based on cost, helping to ensure least-cost ancillary service procurement.

Performance-based. Resources are rewarded for accuracy and agility of response to system operator signals.

Transparent. Market rules are documented and freely accessible, and changes to market rules are subject to public scrutiny and stakeholder feedback. Market rules are applied equally to all participants.

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4.2.2.1 Market Designs to Incentivize Solar and Wind to Provide Ancillary Services

Differentiated Markets for Essential Reliability Services

Separate market products for ancillary services can provide more opportunities for solar and wind generator participation. For example, a combined frequency regulation market (combining both regulation up and regulation down services) requires generators to provide capacity for regulation in both directions. Solar and wind generators may be unable to provide regulation in both directions based on financial considerations and/or resource conditions. Separate (differentiated) regulation products can help ensure all resources can contribute regulation services when needed in the system. A hypothetical wind plant with power potential that ranges from 40 MW to 15 MW over several hours can provide up to 15 MW of regulation down for the duration of the period with relatively low total energy curtailment. If the market design only allows for combined regulation services, the wind plant can provide only 7.5 MW of regulation up and 7.5 MW of regulation down while incurring significant energy curtailment. A combined regulation product may preclude this wind plant from bidding into the regulation market, even though it can technically provide down regulation for the entire period.

Performance-Based Compensation for Frequency Regulation

Because solar and wind generators can provide faster and more accurate responses to AGC signals than conventional resources, performance-based compensation can offer more incentive for solar and wind plants to provide regulation. In response to FERC Order 755, enacted in 2011, wholesale market operators in the United States began to implement performance-based compensation for resources that participate in the regulation market. For example, CAISO accepts separate bids for regulation capacity (up and down) as well as "regulation mileage," which is defined as the absolute change in AGC setpoints between every four-second control signal interval. The mileage payment that each resource receives is adjusted based on the actual response, the accuracy of the response relative to the regulation signal, and the ramp capability of the resource. In other words, regulation mileage is a method to provide market-based compensation for actual regulation movement in response to AGC control signals.

Co-optimization of Energy and Ancillary Services Markets

The bidding strategies of individual generators is hard for a system operator to predict. Running co-optimized markets can prevent volatility in ancillary service markets.

Co-optimization can be explained using the following example (adapted from Chen et al. 2012): a system operator runs an energy and a regulation up market, each of which settles at an MCP. The system operator requires 50 MW of energy and 5 MW of regulation up and receives the bids in Table 1. Generator A, a VRE generator, has a close to zero marginal cost of production, which enables it to offer ancillary services whenever the price is above that of energy. Generator B, a thermal generator, is constrained by minimum generation thresholds that pose additional operational costs to provide regulation up.

Table 1. Example of Bids for Electricity and Regulation Services from Different Generator Types

Generator	Capacity (MW)	Electricity ($/MW)	Regulation Up ($/MW)
A: VRE	40	1	2
B: Thermal	20	3	6

A sequential (or not co-optimized) market would first resolve one market, then use the remaining available capacity to clear the second market. In this example, if the energy market cleared first, the total cost would be:

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($3 * 40MW) + ($3 * 10 MW) + ($6 * 5 MW) = $180

But in a co-optimized model, the relative price increase in regulation up bids ($6-$2) is found to be greater than the marginal price of energy offerings ($3-$1), so the least expensive offering of ancillary services is pursued first. In a co-optimized market, the total cost is:

($3 * 35MW) + ($3 * 15MW) + ($2 * 5MW) = $160

This example demonstrates that co-optimization allows the system operator to avoid the greater increase in price between the price of ancillary services offered by the two generators. This provides a lower total cost to the system operator, while limiting the volatility in any single market.

Intraday Procurement and Market Settlement for Ancillary Services

Historically, ancillary services are procured in the day-ahead market. A day-ahead market increases the risk for VRE participation because generation is subject to intraday resource uncertainty. In most markets, VRE resources must make up for real-time shortfalls in their day-ahead ancillary service obligation by purchasing from another ancillary service provider in a secondary market or pay a penalty. One method to reduce this risk is to introduce intraday settlements for ancillary service markets, including co-optimization of ancillary services and real-time energy markets. By moving the market settlement period closer to real-time, solar and wind generators are subject to less uncertainty in the resource forecast and thus have lower risk of undersupplying their ancillary service obligation. For example, PJM currently uses co-optimization to simultaneously determine real-time requirements and market prices for reserves (including frequency regulation and replacement reserves) and energy in every 5-minute interval for the 12 intervals of the upcoming market hour (PJM 2018).

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