Essential Reliability Service Requirements from Utility-scale Solar and Wind in Bulk Power Markets

by

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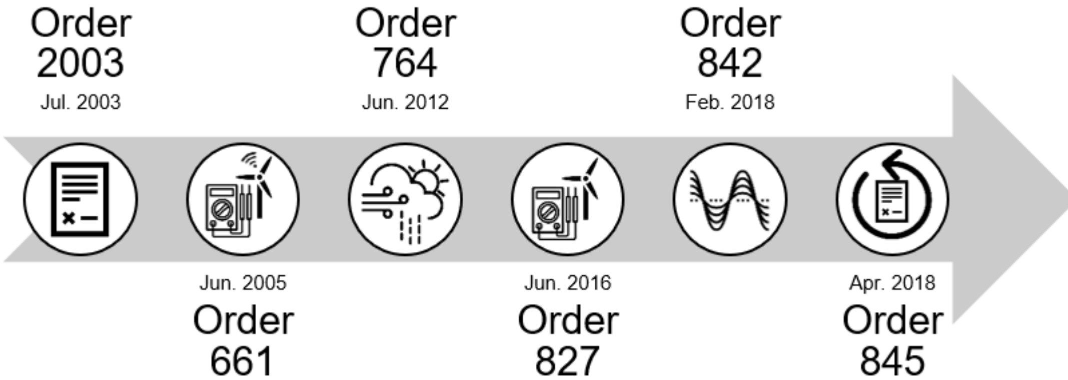
EXECUTIVE SUMMARY

Essential Reliability Services (ERS) stabilize the grid through frequency and voltage support. For decades, the inherent provision of ERS by central, dispatchable, generators led to an abundance of frequency and voltage support, such that planners and operators of the U.S. Bulk Power System (BPS) did not require robust techniques to monitor these attributes. However, this paradigm has shifted over the past two decades as reliability concerns from larger penetrations of variable energy resources (VERs) have emerged. Among the increasing penetration of VERs, solar photovoltaics (PV) and wind turbines dominate. The core research objective for this master's project is to answer how ERS requirements are changing over time for utility-scale wind and solar in bulk power markets.

In recent years, several demonstrations of advancements in power electronics conducted under the leadership of the National Renewable Energy Laboratory (NREL) have shown that VERs are also capable of accurate and rapid response to grid disturbances. Therefore, on the plant level, there is no significant technical barrier. But some operational challenges, as well as uncertainty and accuracy problems remain.

In addition to simulated demonstrations, US regional grid operators and European countries have taken the initiative to change their operation to accommodate growing renewables within their territories. Since the Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator (MISO) and Public Service Company of Colorado (PSCO) have significant wind penetration, they have already implemented several strategies to cope with ERS concerns. For European countries, frequency response capability and responsibility have been updated and relatively well defined for all generators including VERs. Also, several European regions' ancillary services and balancing markets have been reformed. Specifically, the reforms open power markets to non-conventional providers and enlarge their footprint.

Besides technical demonstrations and regional market innovations, Federal level interconnection rules and reliability requirements have evolved. The Federal Energy Regulatory Commission (FERC) serves as the rule-making authority for the U.S. BPS. Over the past century, U.S. BPS interconnection requirements have become more standardized and open to non-utility entrants. FERC Order 2003 created *pro forma* Large Generator Interconnection Procedures (LGIP) and a *pro forma* Large Generator Interconnection Agreement (LGIA), setting the minimum requirements and standardized approval procedure for generators larger than 20 MW interconnecting to the United States BPS. The LGIA establishes the standard terms and conditions for ensuring safe and reliable generator interconnection with the BPS. The LGIA also requires all parties to adhere to Good Utility Practice, which often refers to the North American Electric Reliability Cooperation (NERC) Reliability Standards, guidance, and policies. After FERC Order 2003, there have been five FERC Orders that have modified the pro forma LGIA to enhance ERS provision and accommodate wind & solar.



After documenting recent developments in technical capability, market innovation, and federal level requirements, this report provides an outlook for future developments for ERS provision from wind and solar and associated interconnection requirements. The outlook section summarizes viewpoints from five experts in different areas of the power sector and the findings of this report. The report discusses evolving ERS expectations for utility-scale solar and wind, potential advantages (e.g., reduced cost, positive environmental impact, and higher speed and accuracy), the lack of technical barriers, and remaining economic and market barriers (e.g., low marginal costs, fixed-price power purchase agreements (PPA)). As for regulatory and market outlook, expectations for wind and solar penetration, outlook on changes to the LGIA and LGIP, and comparison between market and mandate mechanisms are discussed. Specifically, the following considerations may motivate FERC to make future modifications to the pro forma LGIA and LGIP:

1. A new series of FERC orders on ERS may follow Order 842,
2. Different compensation structures may break the economic barriers to wind and solar ERS provision,
3. Uniform interconnection requirements are expected for all technologies,
4. The work of NERC's Inverter-based Resource Performance Task Force is expected to affect interconnection requirements from wind and solar, and
5. Trade groups can influence interconnection requirements

Hence, the conclusion is that wind and solar are capable of fast and accurate ERS provision, and for some specific ERS, they may perform even better than conventional generators. ERS provision from wind and solar can lead to potential economic and environmental benefits and can be provided in both regulated and deregulated market structures. Although some economic barriers and market design challenges remain, regulation and market design will continue to evolve to resolve these issues.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

ACRONYMS, INITIALISMS & ABBREVIATIONS

AC	Alternative Current
ACE	Area Control Error
AGC	Automatic Generation Control
ANSI	American National Standards Institute
APC	Active Power Control
AWEA	American Wind Energy Association
BA	Balancing Authority (or Area)
BAL	Resource and Demand Balancing (NERC Reliability Standards)
BESS	Battery Electric Storage Systems
BPS	Bulk Power System
CAISO	California Independent System Operator
CHP	Combined Heat and Power
CIP	Critical Infrastructure Protection
CPS1	Control Performance Standard 1
CPUC	California Public Utilities Commission
CSA	Construction Service Agreement
DC	Direct Current
DER	Distributed Energy Resource
DIR	Dispatchable Intermittent Resource
DOE	United States Department of Energy
DSR	Demand Side Response
ECC	Economic Carrying Capacity
EI	Eastern Interconnection
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIPC	Eastern Interconnection Planning Collaborative
EOC	Enhanced Operating Capability
EPA	Environmental Protection Agency
EPACT92	Energy Policy Act of 1992
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ERS	Essential Reliability Service
ERSTF	Essential Reliability Services Task Force (NERC)
ERSWG	Essential Reliability Services Working Group (NERC)
EU	European Union
EWG	Exempt Wholesale Generator
FCR	Frequency Containment Reserve
FCRD	Frequency Controlled Disturbance Reserve
FERC	Federal Energy Regulatory Commission
FES	Interconnection Feasibility Study
FFR	Fast Frequency Response
FRO	Frequency Response Obligation
FRR	Frequency Restoration Reserves
FS	Interconnection Facilities Study
GE	General Electric

GO	Generator Owner
HQ	Hydro Quebec
Hz	Hertz
IBR	Inverter-Based Resources
IBRPTF	Inverter-Based Resource Performance Task Force (NERC)
IC	Interconnection Customer
IEEE	Institute of Electrical and Electronics Engineers
IFRO	Interconnection Frequency Response Obligation
ISA	Interconnection Service Agreement
ISO	Independent System Operator
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedures
LTRA	Long-Term Reliability Assessment
LVRT	Low-Voltage Ride Through
MISO	Midcontinent Independent System Operator
MP	Master's Project
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NGCC	Natural Gas Combined-cycle
NOPR	Notice of Proposed Rulemaking
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
OC	Operating Committee (NERC)
PC	Planning Committee (NERC)
PFR	Primary Frequency Response
POI	Point of Interconnection
POR	Primary Operating Reserve
PPA	Power Purchase Agreement
PPC	Power Plant Controller
PSCO	Public Service of Colorado
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act
PV	Photovoltaic
QF	Qualifying Facility
QI	Quebec Interconnection
RAS	Reliability Assessment Subcommittee (NERC)
RCC	Resource Contingency Criteria
REC	Renewable Energy Certificate
RoCoF	Rate of Change of Frequency
RR	Replacement Reserves
RS	Resources Subcommittee (NERC)
RTO	Regional Transmission Organization
SAMS	System Analysis and Modelling Subcommittee (NERC)
SAR	Standard Authorization Request (NERC)
SCADA	Supervisory Control and Data Acquisition
SG	Sufficiency Guideline
SGIA	Small Generator Interconnection Agreement

SGIP	Small Generator Interconnection Procedures
SIR	Synchronous Inertial Response
SIS	Interconnection System Impact Study
SOC	State of Charge
SOR	State of Reliability
SPP	Southwest Power Pool
SVC	Static VAR Compensator
TI	Texas Interconnection
TSO	Transmission Service Operator
TO	Transmission Owner
TP	Transmission Provider
UFLS	Under-frequency Load Shedding
UL	Underwriter's Laboratory
VAR	Voltage and Reactive Controls (NERC Reliability Standards)
VAR	Volt-Ampere Reactive
VER	Variable Energy Resource
VIU	Vertically Integrated Utility
VPP	Virtual Power Plant
VSC	Voltage Source Converter
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WTG	Wind Turbine Generator

1. INTRODUCTION

1.1. Topic Description

Essential Reliability Services (ERS) provide frequency and voltage support to the Bulk Power System (BPS) (NERC 2016b). These services support the primary function of the grid and are necessary to prevent widespread system failure.

For decades, the inherent provision of ERS by central, dispatchable generators led to an abundance of frequency and voltage support, such that planners and operators of the BPS did not require robust techniques to monitor these attributes (NERC 2014). A combination of market, policy and plant-specific factors has led to sustained retirement of thermal generation capacity in the United States (U.S. DOE 2017a). For the most part these resources have been replaced by natural gas, wind, and photovoltaic (PV) solar power plants (EIA, 2018). Utility-scale solar and wind, both considered variable energy resources (VERs), accounted for 36% of the United States' capacity additions in 2018 (EIA 2018). Due to the intermittency and variability of these resources and their different operating characteristics compared to conventional power plants, high penetrations of solar and wind are expected to affect the grid reliability (Kroposki 2017). The reliability effects of integrating utility-scale wind and solar have already been seen in the California Independent System Operator's (CAISO) *Duck Curve* and other recent cases (CAISO 2016).

Recent demonstrations of advancements in power electronics have shown that VERs are capable of accurate and rapid response to grid disturbances (Gevorgian and O'Neill 2016; Loutan et al. 2017). However, the ERS capabilities of VERs are limited by market structures and regulations designed for conventional resources. Utilizing the ERS framework developed by the North American Electric Reliability Corporation (NERC), this report includes:

- Technical demonstrations of ERS capability from utility-scale wind and solar (Section 3),
- Innovations in U.S. and European Markets for ERS (Section 4),
- Changes to Interconnection Requirements for ERS (Section 5),
- Discussion of the current state of ERS in the North American BPS and the policy influence of NERC's Subcommittees on ERS (Section 6), and an
- Outlook on ERS provision from utility-scale wind and solar (Section 7).

1.2. Research Objectives

The principle objective of our client-centered Master’s Project (MP) is to characterize the current state of ERS provided by utility-scale VERs in bulk power markets and provide an outlook for future developments. Our client, ScottMadden, has identified four specific objectives to guide our work:

1. Outline grid reliability services that could be provided by utility-scale wind and solar;
2. Catalog recent developments (e.g. NERC reports) and changes to FERC’s *pro forma* Large Generator Interconnection Agreement (LGIA);
3. Summarize how changes are being implemented in bulk power markets in North America and Europe; and
4. Provide an outlook for future developments, issues, and/or changes to FERC’s LGIA.

Accomplishing these objectives has required the synthesis and analysis of a variety of technical reports, regulatory filings, and expert interviews. Our work will also assess the current state of utility-scale solar ERS within the context of ScottMadden’s “Solar Trifecta”—a framework that describes the necessary market requirements for overcoming the operational challenges of utility-scale solar and moves towards cost-competitive solar resources that provide similar reliability attributes to conventional generation (ScottMadden 2017).

1.3. Literature Review

The capability and operational practices of utility-scale solar and wind providing frequency and voltage support is an ongoing research area. The research scope includes interconnection, balancing authority, plant, and generator levels. Traditional utility-scale solar and wind are non-dispatchable and variable resources. The market design rewards only the energy contribution from solar and wind, hence utility-scale solar and wind farms are usually operated at the maximum available capacity in real time. The grid reliability is determined by the system ability to balance load and generation at all time. The famous California Duck Curve, which represents the system demand of a large amount of load following ramping resources due to solar variability, reveals one challenge of integrating more non-flexible resources on the grid (CAISO 2016).

The National Renewable Energy Laboratory (NREL) (Bloom et al. 2016) conducted interconnection modeling at 5-minute resolution for the Eastern Interconnection to examine the impacts of high levels of variable resource integration. Forecast errors, weather uncertainties, seasonality, and system operating constraints were examined to see the changes of system reliability and economic efficiency due to generation variability. NREL studies revealed a significant ramp increase and more demand for inter-regional transmission. However, this interconnection modeling did not include reliability risks related to voltage and frequency control, nor did it measure the technical capability of wind and solar generation to provide grid balancing support. Inverter-based resources (IBR), such as solar PV, have many characteristics that are different from synchronous generators. Additional research effort by NREL (Tan et al. 2018) studied interconnection-level frequency response under high solar PV penetration. The direct effect of increasing IBR generation is the reduction of system inertia. The study recognized the fast power output adjustment capability of solar PV and recommended the use of solar PV frequency control to meet future frequency support obligation when renewable penetration levels are higher than 45%.

Closely linked to the impact studies on high renewable penetration, the potential for flexible and controllable solar and wind resources to be part of the solution for improving reliability at higher penetrations is under exploration. Solar developer First Solar describes their vision of future solar operation in *The Solar Trifecta: A Path to Smart Utility-Scale Solar* (ScottMadden 2017), where they discuss the factors that will enable technology advances to unlock the full potential of utility solar. Mainly, smart inverters and storage technology will bring about the transition of utility-scale PV from a traditional, non-dispatchable resource to a controllable or even smart asset, effectively reducing the differences in operational characteristics between solar and conventional generators. In addition to technical advances, this transition also requires changes to operational practices. For example, solar would need be scheduled under the maximum available capacity to be able to ramp up. China State Grid Electric Power Research Institute (Wu and Gao 2017) mapped the currently available technological options for variable-speed wind turbines (Section 3) to provide different types of inertial control and frequency control (Section 2.2.1).

Flexible grid operation, especially from solar and wind, has the potential to unlock reliability benefits. Energy and Environmental Economics (Nelson et al. 2018) calculated the system balancing and reserves demand as well as the system solar production costs savings under four different solar PV operational modes (ranging from non-dispatchable to full flexibility). The results showed that increasing solar flexibility—in the most extreme case, enabling both upward and downward dispatch—could effectively reduce the need for other flexible resources such as natural gas combined-cycle (NGCC) power plants and storage. Flexibility was shown to increase both the average and marginal value of solar energy. NREL (Denholm et al. 2016) calculated the grid economic carrying capacity (ECC) of different levels of flexible operation. ECC measures the maximum amount of variable resources that can be economically integrated with the grid. The higher the ECC, the higher the system value of the variable resources. Wind or solar providing spinning reserves is one of the flexibility options. Other options include demand response, energy storage, more flexibility from NGCC and coal generators, and cooperation between balancing authorities. The ECC effects in California, Florida, and the Southwest Power Pool are region-specific, and the net additive benefits may not be explained by the addition of different flexibility options. The gains from VERs flexibility are relatively trivial compared to options such as storage capacity addition. However, the ECC calculation does not capture the benefits of VERs providing frequency response and regulation.

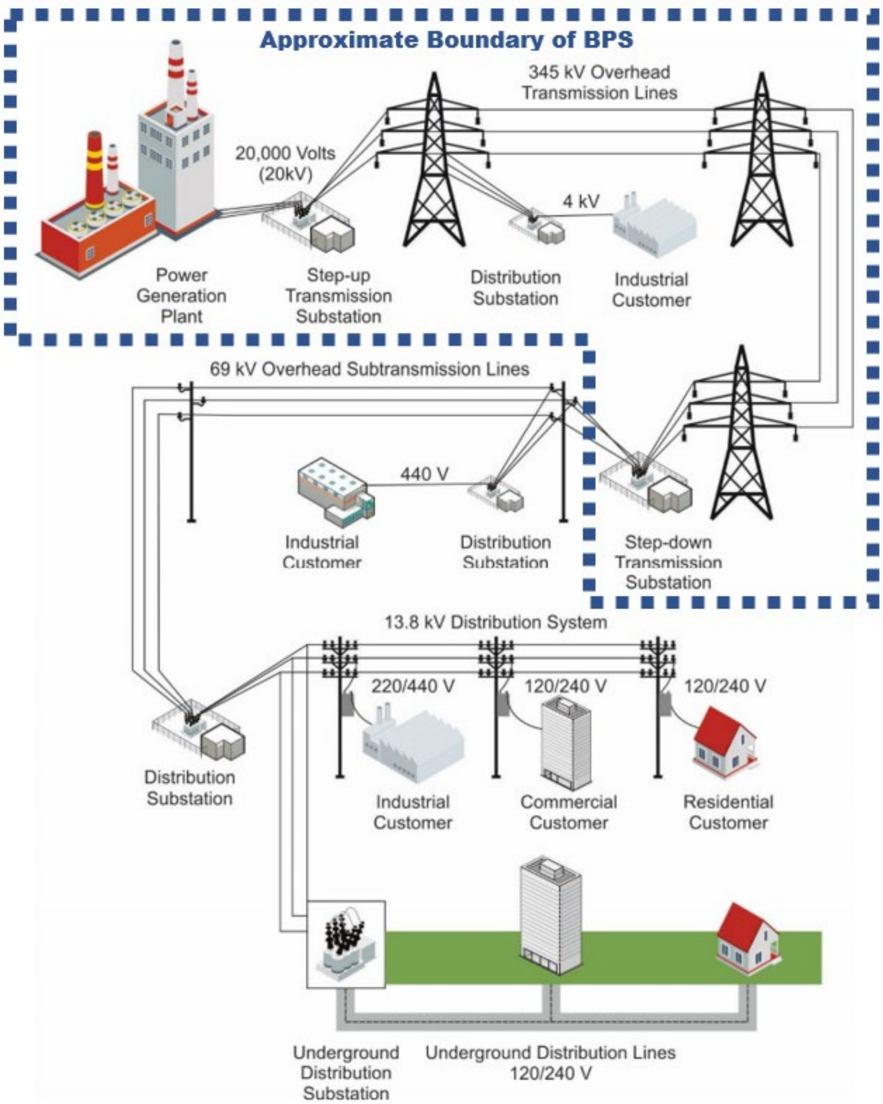
Many technology mapping exercises, control technique discussions, and integration simulations have explored the technical readiness and potential benefits of increasing the flexibility of utility-scale solar PV and wind turbines. However, although there is consensus that regulation and market structures are designed primarily for conventional generators and need to be updated for increasing penetrations of VERs and other emerging grid technologies, specific discussions on regulation and market structure that capture the full technical capability of solar PV and wind are relatively limited.

2. BACKGROUND

2.1. The North American Bulk Power System: Regulation, Topology, and Market Structure

North American BPS facilities are generally operated at a voltage greater than or equal to 100 kilovolts (kV) (Figure 1) (FERC 2014a).

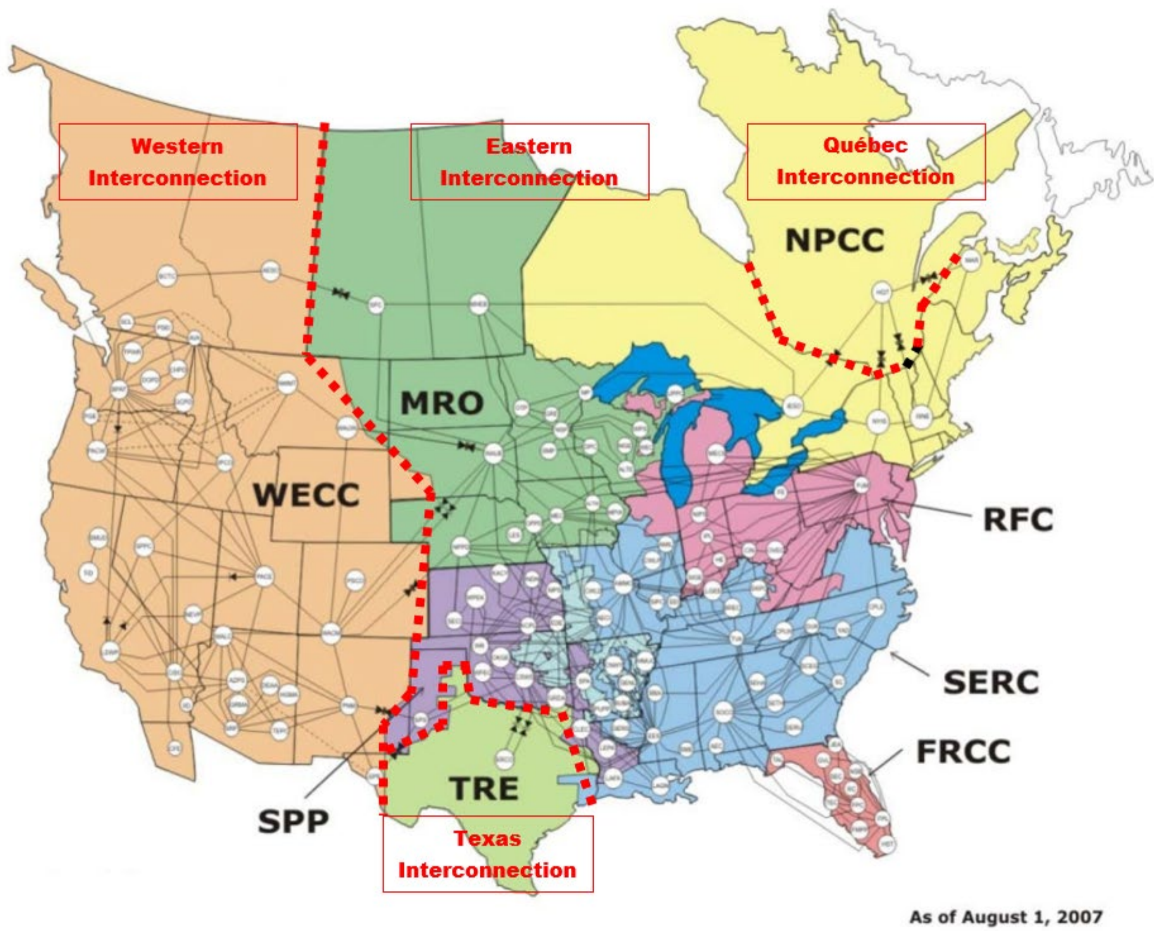
Figure 1. Schematic of U.S. Electric Grid and Typical Boundary of BPS



Adapted from (U.S. DOE 2016)

The North American BPS consists of four interconnected electric energy transmission networks that cover most of the continental United States and part of Canada (Figure 2). The Eastern Interconnection (EI), Western Interconnection (WI) and Texas Interconnection (TI) cover the continental United States with the Quebec Interconnection (QI) spanning eastern Canada.

Figure 2. Interconnections, Regional Reliability Councils, and Balancing Authorities within North American BPS



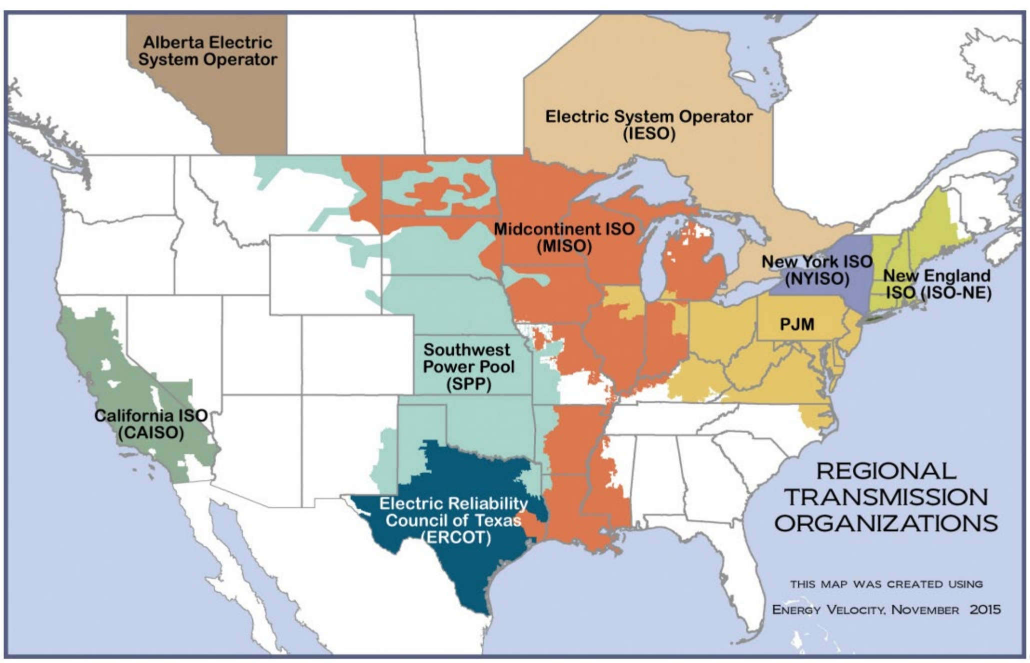
Adapted from (NERC 2011)

The Federal Energy Regulatory Commission (FERC) has jurisdiction over the interstate transmission of electricity, natural gas, and oil. Hence, FERC serves as the rule-making authority for the U.S. BPS. FERC is an independent federal agency with a mandate to ensure the safe, affordable, and reliable operation of the BPS on a technology neutral basis (Greenfield 2018).

The Northeast Blackout of August 2003 led to the formation of an Electric Reliability Organization (ERO) for the United States. On August 14, 2003, a cascading blackout occurred after the tripping of a 345-kV transmission line, affecting over 50 million people in the portion of Eastern Interconnection (NERC 2004). A series of violations and inadequate reactive power resources were among the root causes identified during subsequent investigation (NERC 2004). In July 2006, NERC was certified as the U.S. ERO. NERC has the authority establish mandatory Reliability Standards and voluntary Reliability Guidelines for the BPS. NERC, and its seven regional entities (Figure 2), are the key technical bodies that monitor U.S. BPS operational conditions and develop and enforce Reliability Standards.

In Regional Transmission Organizations (RTO) and Independent System Operators (ISO) the BPS is operated as a competitive wholesale market (Figure 3). In these regions, markets for bulk electricity, capacity, and ancillary services are used to reliably operate the BPS and ensure adequate resources for the planning horizon. Another key aspect of RTO and ISO regions is that Transmission Owners (TOs) are not typically allowed to be Generator Owners (GOs)—this concept is referred to as “functional unbundling” (FERC 1996). Regions without wholesale markets typically follow the vertically integrated utility (VIU) model where one company owns both transmission and generation assets (FERC 2015a). RTOs, ISOs, and VIUs are considered Balancing Authorities (BAs), which have certain responsibilities for balancing generation and load within their footprint. BAs are depicted as white circles in Figure 2.

Figure 3. Regional Transmission Organizations and Independent System Operators



(FERC 2015a)

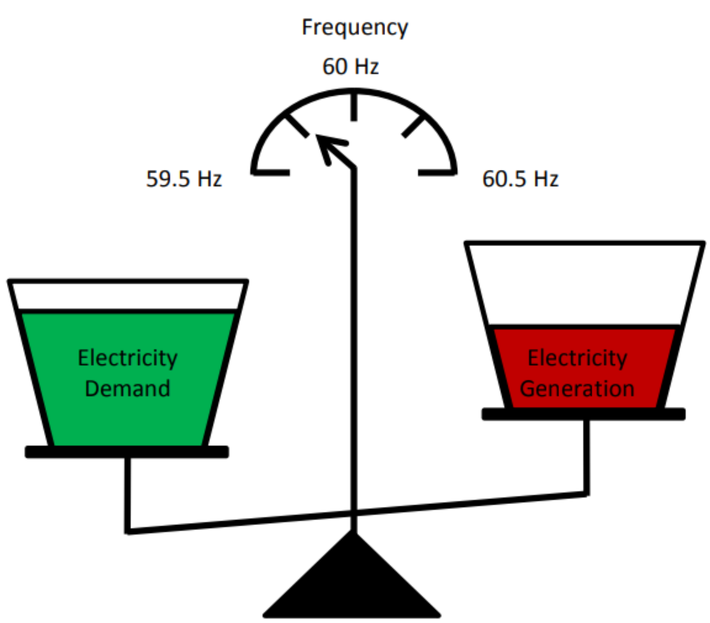
2.2. Electric Power System Reliability

A reliable power system is always expected to balance power supply and demand. Therefore, besides electricity generation, resources that can respond to system disturbances and help restore the generation-load balance are also essential to reliable grid operation. The latter resources often called ancillary services or grid support services. The instantaneous balance of generation and load requires the consideration of two parameters: frequency and voltage.

2.2.1. Inertia and Active Power Control

Frequency is a property of the entire interconnection (NERC 2018b). All interconnected facilities and devices within a single interconnection experience and contribute to the same frequency changes. The nominal frequency of the North American BPS is 60 Hertz (Hz). Over-frequency events occur when generation is greater than load, and under-frequency events occur with the opposite (Figure 4).

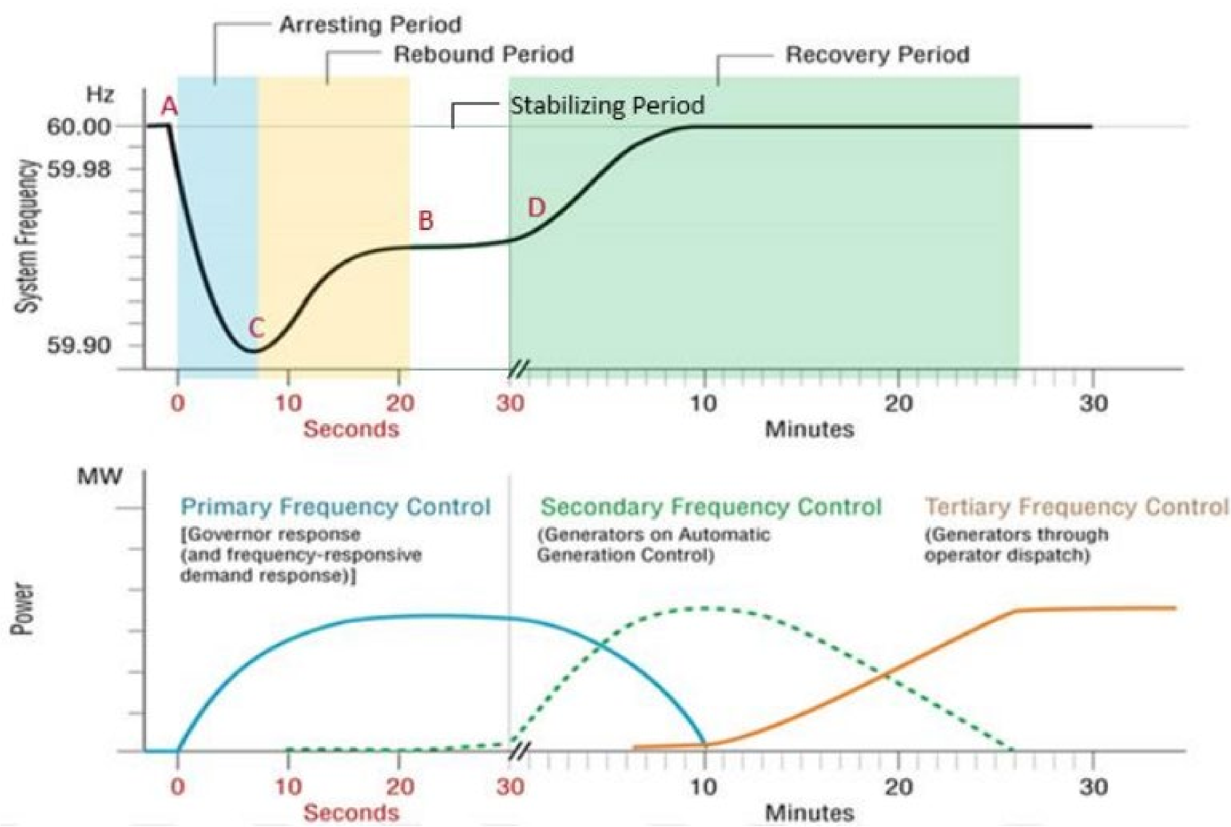
Figure 4. Frequency Balance



(Miller et al. 2015)

The unexpected loss of a generator or customer load can result in an immediate decline or increase of interconnection frequency (Figure 5). Grid operators use several frequency controls following a disturbance to avoid the first level of under-frequency load shedding (UFLS). Interconnections within the North American BPS have UFLS schemes that are designed to disconnect load from the system when the interconnection frequency reaches critical values below 60 Hz as a last resort to avoid a cascading power outage (NERC 2015).

Figure 5. Frequency Response Following a Sudden Loss of Generation



(Eto et al. 2010; NERC 2018l)

Frequency response typically ranges from seconds to minutes and is usually conceptualized as a negative deviation (loss of generation) using the following parameters shown on Figure 5:

- **Pre-disturbance Frequency (Point A):** The interconnection frequency at T_0 prior to disturbance.
- **Frequency Nadir (Point C):** The lowest interconnection frequency between T_0 and T+52 seconds
- **Absolute Frequency Minimum (Point C' or C_n):** The lowest interconnection frequency before T+180 seconds. This supplemental nadir measurement (C_n) is used to capture prolonged frequency withdrawal and is not depicted in Figure 5.
- **Stabilization Period Frequency (Point B):** Average interconnection frequency between T+20 to T+52 seconds.

- **Settling Frequency (Point D):** Interconnection frequency at T+60 seconds.

The interconnection recovers from a frequency deviation by a combination of inertia, fast-frequency reserves, primary frequency control, secondary frequency control, and tertiary frequency control (Figure 5). Note that "control" describes the capability or operator action while "response" (e.g., Primary Frequency Response) describes the actual frequency support provided by the control. NERC describes frequency response performance across four time periods: the arresting period, rebound period, stabilizing period, and the recovery period (Figure 5) (NERC 2018l). Each timeframe and associated frequency response is discussed below:

- **Arresting Period (T_0 to T_C seconds):** The arresting time period begins with generation loss at T_0 and ends at Point C. Total frequency decay must be less than the first level of UFLS to avoid load-shedding.

  The earliest counteraction against system frequency deviation has traditionally been supplied by *inertia*. System inertia is traditionally provided by generators that have turbines synchronized to the grid frequency, which include fossil-fuel and hydro power plants. These spinning masses inject kinetic energy into the system to help arrest the frequency deviation. This response is intrinsic, immediate (fractions of a second), and does not require any operator action (NERC 2014). Primary frequency response (PFR) from governors may also begin during this period (see full description below) (NERC 2015). Newer capabilities, such as synthetic inertia from wind turbines (Section 3), demand response, and fast-frequency response (FFR) are also capable of response during the arresting period (NERC 2016b). The Rate of Change of Frequency (RoCoF) immediately following the loss of load or generation is inversely proportional to the amount of inertia and other fast reserves available (Figure 5, A to C) (ENTSO-E, n.d.).

- **Rebound Period (T_C to T+20 seconds):** Primary Frequency Response has begun; frequency is typically greater than the Point C and less than Point A.

  Primary frequency response is provided at the plant level by individual governors (or governor-like controls). These governors provide an automatic increase or decrease in plant power output that corresponds to the size frequency disturbance, usually within seconds (Quint and Ramasubramanian 2017). The full governor response is usually within thirty seconds of the disturbance, meaning that PFR has a role in both the arresting and rebound periods (NERC 2015). Governor response is automatic and depends on plant-level settings of deadband and droop (NERC 2018l).

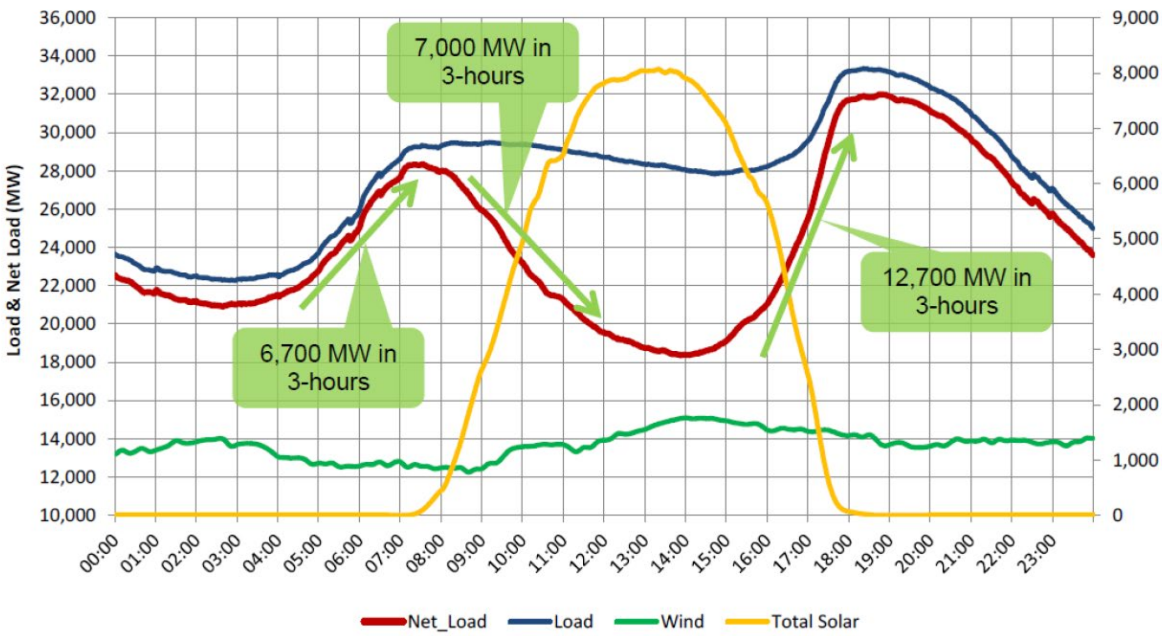
> *Governor Deadband*: The sensitivity range of the governor, measured in Hertz (Hz). Only system frequencies outside of the deadband will result in a governor response.
>
> *Governor Droop*: The percent deviation in interconnection frequency (Hz) that would "move the generator across its full operating range" (Quint and Ramasubramanian 2017). The smaller the droop settings, the more sensitive the governor response to a frequency deviation. For example, a 5% droop setting means that a positive frequency deviation of 3 Hz (5% of the nominal 60 Hz) would result in the governor reducing generator power output to the minimum level (Quint and Ramasubramanian 2017).

- **Stabilization Period (T+20 to T+52 seconds):** PFR has stabilized frequency at a value below Point A, which is a consequence of governor droop control settings (NERC 2018l).
- **Recovery Period (about T+5 to T+15 minutes):** Generators are Secondary and Tertiary Frequency Response restore nominal frequency and replenish reserves.

  Secondary frequency response and *tertiary frequency response* are initiated by external operators using Automatic Generation Control (AGC). AGC signals experience a two to six second delay traveling from central control center to the power plant (NERC 2018l). Secondary frequency response takes between five and 15 minutes restore the scheduled system frequency (NERC 2018l). In tertiary frequency response, the resources used for primary and secondary frequency response are gradually replaced by a third tier of frequency reserves, which allows the primary and secondary frequency response resources to be available for the next frequency event.

Ramping capability is another aspect of active power control on the BPS that refers to the capability of a generator to rapidly increase or decrease output to follow large changes in net demand, usually caused by the inherent variably and uncertainty of wind and solar output (NERC 2014). Net demand is calculated by subtracting wind and solar generation from the total system load. The slope (MW/min) of the resulting profile shows the "ramps" that dispatchable resources must achieve to balance the generation with load absent of wind and solar (Figure 6). Unlike frequency response, ramping capability is needed during normal grid operations with a time scale that is often measured in hours (NERC 2018d). Traditionally, flexible natural gas plants have provided most ramping capability to the grid (U.S. DOE 2016)

Figure 6. Example of Net Demand Ramping

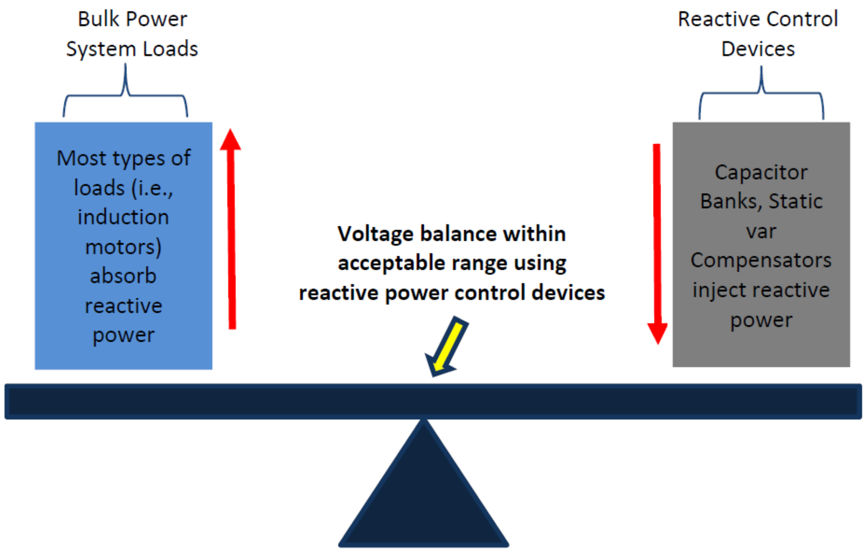


(NERC 2014)

2.2.2. Reactive Power and Voltage Control

Reactive power is a characteristic of the Alternating Current (AC) power system. While frequency is managed by controlling real power output and consumption, voltage is maintained by managing reactive power production and absorption constantly throughout the operational period (Figure 7) (NERC 2014). Reactive power supports system voltage levels, which control the amount of real power that can be transmitted across the BPS to balance load (NERC 2016c). Voltage that is too high can damage to electrical equipment, while voltage that is too low can cascade across the BPS causing a black-out (NERC 2016b). Reactive power cannot be transmitted long distances, so voltage support issues tend to be more local than frequency issues (NERC 2015). Voltage support resources are usually needed near the location of deficiency (NERC 2016c).

Figure 7. Reactive Power Balance

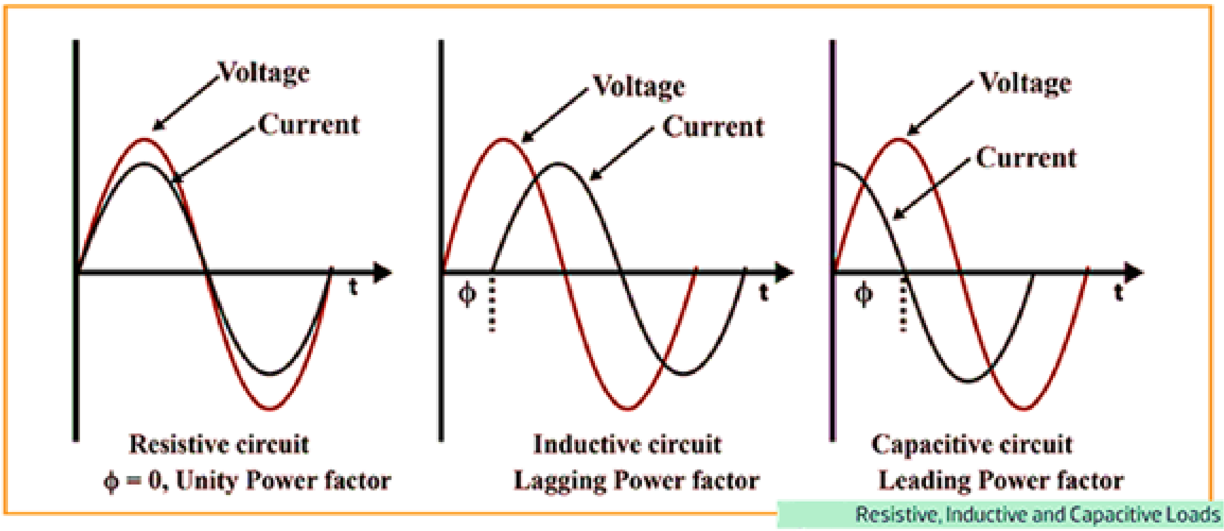


(NERC 2014)

There are static and dynamic reactive power resources: static resources have pre-set, fixed reactive power output, whereas dynamic resources can automatically adjust reactive power output in response to voltage deviations within a certain level of bandwidth (NERC 2016c). Static reactive power resources are usually produced and consumed by capacitors, reactors, and power lines (NERC 2016c). Dynamic reactive power resources involve both synchronous and non-synchronous generators, synchronous condensers, and voltage source converter (VSC) devices (NERC 2016c).

The dynamic power factor setting of a generator determines its ability to react to voltage changes by absorbing or injecting reactive power. This capability is provided over a range of power factors. A generator's power factor is considered "lagging" if its voltage waveform is behind its current waveform (Figure 8). A lagging power factor absorbs reactive power and lowers system voltage. Leading power factors inject reactive power and increase system voltage.

Figure 8. Reactive Power Factor Control



(Jenkins 2017)

2.2.3. Voltage and Frequency Disturbance Performance

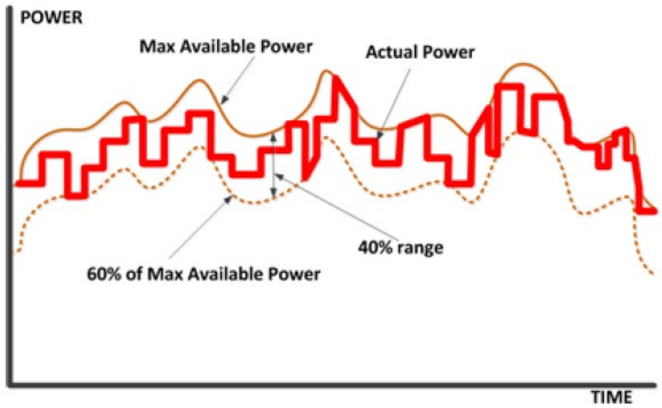
Often, as a condition of interconnection, generators have protective relays that automatically disconnect the resource (or "trip") from the BPS should there be large disturbance in frequency or voltage (FERC 2003). These relays are set to limit damage to the generating equipment as well as the transmission system (FERC 2003). However, premature disconnection of resources can inhibit restoration of scheduled frequency and voltage following a disturbance (NERC 2018j). For this reason, frequency and voltage *ride-through* capability is an important characteristic for resources interconnected to the BPS. NERC Reliability Standard PRC-024-2 delineates "no trip zones" for BPS generators that extend over certain frequency and voltage ranges for the timeframe immediately following a disturbance (Appendix C) (NERC 2019b).

2.2.4. Operational Flexibility

Fully flexible resources operate with both headroom and footroom (Nelson et al. 2018). Headroom refers to the amount of capacity (usually in megawatts, MW) between the plant's actual output and its maximum capability. Conversely, footroom refers to the maximum downward dispatch before the generator reaches its minimum power output level. Traditionally, natural gas generators have been operated flexibly to accommodate the uncertainty and variability in load (U.S. DOE 2016). Recent demonstrations have shown that it is possible to operate wind and solar with headroom and footroom (Section 3.1.3) (Nelson et al. 2018). Figure

9 is a conceptual depiction of real power up/down regulation controlled by AGC within the headroom band of a solar PV plant.

Figure 9. Conceptual Diagram of Fully Flexible Solar PV Plant (40% headroom)

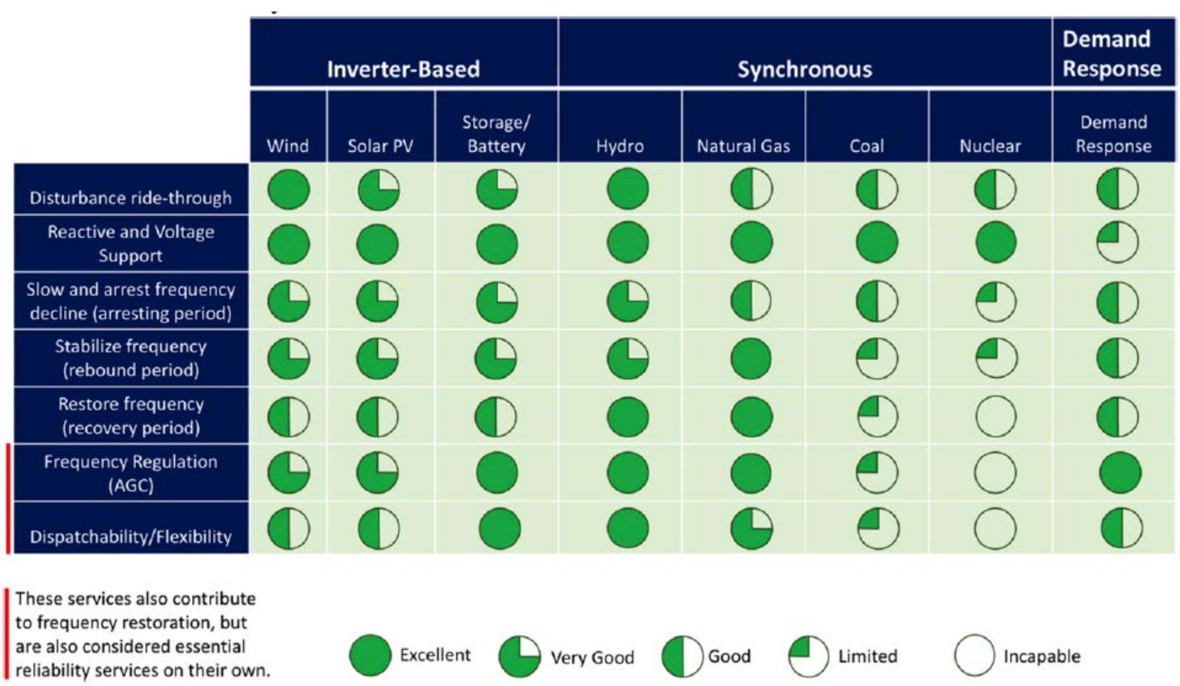


(Gevorgian and O'Neill 2016)

2.2.5. Resource Mix and Resiliency Considerations

Resource mix, both by generator technology and fuel type, has implications on the reliability services that are available to the grid (Figure 10).

Figure 10. Grid Reliability Services by Generator Type



(Milligan 2018)

Black start capability, another grid reliability attribute, allows generators to restart, or a portion of the transmission system to re-energize, without any outside electrical supply (NERC 2014).

BPS *resiliency* depends on the system's "ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event [such as] severe natural events (wildfires, hurricanes, floods, droughts, and earthquakes) and coordinated, extensive physical and cyber-attacks and geomagnetic disturbances" (U.S. DOE 2017a). This is accomplished by either "hardening" the system to withstand impacts or increasing storage and redundancy to improve recovery time following damage (U.S. DOE 2017a). Questions of fuel availability may affect the resilience of certain generator types (U.S. DOE 2017a).

2.3. Essential Reliability Services and Modern Reliability Challenges

Since the ERO's formation, NERC has tracked the reliability implications of the evolving grid. NERC's 2013 Long-Term Reliability Assessment (LTRA) found that traditional system planning and operation methods need to be revised in order to accommodate large penetrations of VERs (NERC 2013b). Their recommendation was to create a new framework for measuring, assessing, and communicating modern reliability challenges and best practice guidelines for operation and planning (NERC 2013b). The Essential Reliability Services framework groups core components of frequency and voltage support that are needed to assure BPS reliability (NERC 2014). The Essential Reliability Services Task Force (ERSTF), and later the Essential Reliability Services Working Group (ERSWG), were active from 2014-2018 and created a technical foundation for reliability assessment and educational materials for industry, regulators, and the public.

2.3.1. The ERS Framework

The ERS framework is divided into two building blocks, frequency support and voltage support (NERC 2014). The general reliability attributes associated with each building block are presented in Table 1. Note that there is some overlap in reliability attributes since they are inclusive of control technologies (e.g., Active Power Control), operational concepts (e.g., Operating Reserves), and reliability performance (e.g., Voltage Disturbance Performance).

Table 1. ERS Reliability Building Blocks

ERS Building Block	Reliability Attributes

Frequency Support	• Inertia
	• Frequency Disturbance Performance
	• Operating Reserves
	• Active Power Control (APC)
	    ○ Frequency Control
	    ○ Ramping Capability

Voltage Support	• Reactive Power/Power Factor Control • Voltage Control • Voltage Disturbance Performance

Adapted from (NERC 2014)

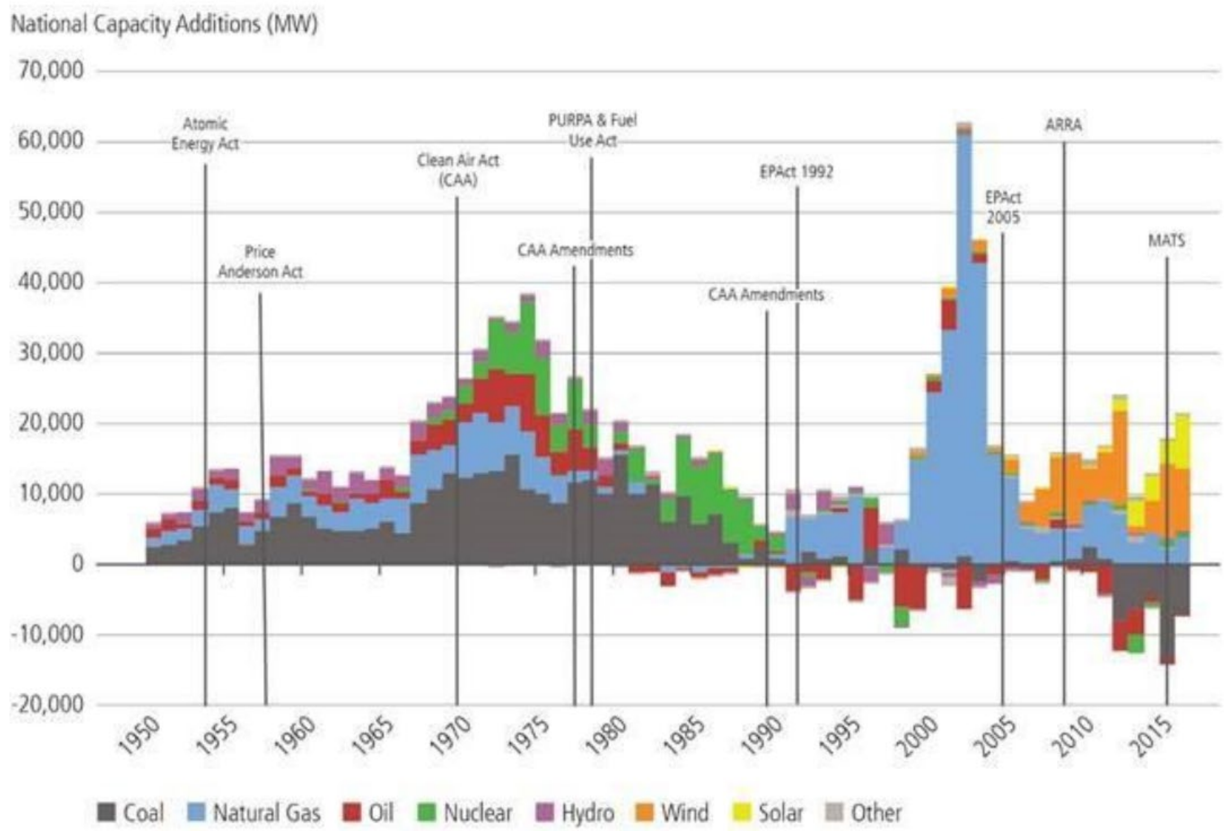
Many ERS reliability attributes correspond with what are considered “ancillary services” by regulators and the power industry (NERC 2014). Ancillary service requirements were established in FERC’s *pro forma* Open Access Transmission Tariff (OATT) in 1996 and were largely conceived for conventional power equipment (NERC 2014). Ancillary services are considered to be a subset of ERS, which is a technology-neutral framework (NERC 2014). Even conventional generators are incapable of meeting all reliability needs. Creating a framework that is more inclusive of new technologies helps contribute to overall BPS reliability.

Maintaining sufficient levels of ERS requires a mixture of technological, market, and regulatory approaches that vary depending on a region’s specific reliability challenges (NERC 2014). So long as there is proper planning, design, and coordination, newer resources with different operating characteristics (e.g., wind and solar) can, and are expected to, contribute to overall BPS reliability (NERC 2016b).

2.3.2. ERS and the Modern BPS

For decades, synchronous resources provided many reliability services to the grid (NERC 2014). The inherent provision of ERS by central, dispatchable generators led to an abundance of ERS, such that planners and operators did not require robust techniques to monitor these attributes (NERC 2014). This paradigm has shifted over the past two decades as variable-output resources that are smaller and less flexible have been become a significant component of the resource mix (Figure 11).

Figure 11. U.S. Net Generation Capacity Additions and Retirements



(U.S. DOE 2017a)

Declining costs, tax credits for renewables, and environmental policy (e.g., Renewable Portfolio Standards) have led to increasing wind and solar capacity on the BPS (U.S. EIA 2019). Also, a combination of cheap natural gas, environmental regulation, and aging has led to recent retirements of coal plants (U.S. DOE 2017a). As synchronous resources with rotating machinery (e.g., coal, natural gas, oil, nuclear, hydro power plants) become a smaller part of the resource mix, total system inertia decreases (Point C, Section 2.2.1) (NERC 2015).

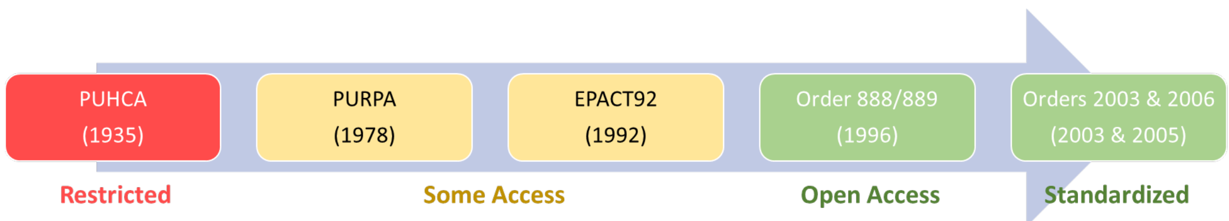
The observation of declining system inertia was one of the forces that led to the formation of the ERS taskforce (NERC 2014). Less system inertia will result in a larger RoCoF following the sudden loss of large generators or loads, which may increase the likelihood of reaching the first level of UFLS. Under normal operating conditions in the North American BPS, the frequency variation is typically less than 0.01 Hz from 60 Hz (NERC 2018a). The setpoint for the first level of UFLS in North American interconnections ranges from 58.5 Hz to 59.5 Hz (NERC 2018a).

2.4. Interconnection Requirements and Operational Norms for Wind & Solar

2.4.1. Overview of U.S. BPS Interconnection Requirements

Over the past century, U.S. BPS interconnection requirements have become more standardized and open to non-utility entrants (Figure 12).

Figure 12. Timeline of Major Policies Dictating U.S Interconnection Requirements



In the past, VIUs controlled the generation, transmission, and distribution of electric power in the United States. The Public Utility Holding Company Act of 1935 (PUHCA) made it very difficult for a non-utility entities to enter the generation business (FERC 1996). The VIUs had a great deal of control over which generators could interconnect to its transmission network and used this market power to give preferential treatment to its own generator assets (FERC 1996). During a global energy crisis in the late 1970s, the U.S. Congress passed the Public Utility Regulatory Policies Act (PURPA) of 1978, which opened the grid to non-utility power producers. Under PURPA, public utilities were required to purchase electricity from Qualifying Facilities (QFs) at avoided cost. In order to meet QF requirements, the facility had to be under 80MW and generate power via certain renewable fuels or co-generation.

Access to BPS interconnection was further increased by the Energy Policy Act of 1992 (EPACT92), which created an Exempt Wholesale Generator (EWG) status for Commission-approved generators that was completely exempt from the interconnection requirements of PUHCA and PURPA (FERC 1996). Shortly thereafter, FERC issued Orders 888 and 889 in April 1996, which required all public utilities to unbundle their businesses and file and Open Access Transmission Tariff (OATT) with the Commission. The policy goal of this Order was to reduce the market power of transmission owners by requiring them to offer "open access non-discriminatory transmission services" to Interconnection Customers (ICs) (FERC 1996).

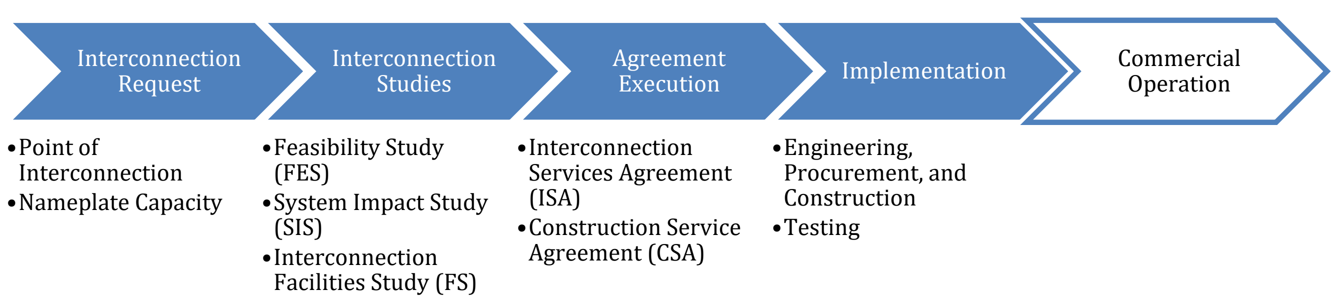
However, the Order did not directly address generator interconnection procedures (FERC 2003).

In July 2003, FERC issued Order 2003 *Standardization of Generator Interconnection Agreements and Procedures*, which amended the Order 888 OATT to include *pro forma* Large Generator Interconnection Procedures (LGIP) and a *pro forma* Large Generator Interconnection Agreement (LGIA), setting the minimum requirements and standardized approval procedure for generators larger than 20 MW interconnecting to the United States BPS. Transmission Providers operating in Interstate Commerce (i.e., under FERC's jurisdiction) must include the LGIA and LGIP provisions in their interconnection agreements (FERC 2003). A separate Final Rule (Order 2006) was issued in May 2005 that established *pro forma* Small Generator Interconnection Procedures (SGIP) and a *pro forma* Small Generator Interconnection Agreement (SGIA) for facilities up to 20 MW. The policy goals of Order Nos. 2003 and 2006 were to:

1. "Limit opportunities for Transmission Providers to favor their own generation,
2. Facilitate market entry for generation competitors by reducing interconnection costs and time, and
3. Encourage needed investment in generator and transmission infrastructure" (FERC 2003)

The LGIP established a four-step study process for interconnection. The following is a general process flow (Figure 13) and summary of the Order 2003 *pro forma* LGIP for large generator interconnection:

Figure 13. General Large Generator Interconnection Process



2.4.2. Reliability Requirements and Good Utility Practice

The LGIA establishes the standard terms and conditions for ensuring safe and reliable generator interconnection with the BPS (FERC 2003). The only ERS requirement stated specifically in the Order 2003 *pro forma* LGIA is for reactive power. Following an Order on Rehearing (Order 2003-A), Article 9.6.1 of the LGIA specified that all generators, unless they are wind plants, must be capable of providing reactive power within the range of 0.95 leading to 0.95 lagging. The *pro forma* LGIP and LGIA have changed alongside with the resource mix and emerging reliability concerns over the past 15 years.

Article 4.3 of the LGIA requires all parties to adhere to Good Utility Practice, NERC Reliability Standards, and Applicable Laws and Regulations (FERC 2016c). Similar baseline requirements are set forth in Article 1.5.1 the SGIA (FERC 2005b).

Good Utility Practice is a term-of-art defined as:

> "**Good Utility Practice** shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region." (FERC 2016c)

Good Utility Practice is inclusive of NERC Reliability Standards, Reliability Guidance, and policies. It also consists of safety codes and technical standards from entities such as the American National Standards Institute (ANSI) and Institute of Electrical and Electronics Engineers (IEEE).

NERC Reliability Standards refer to mandatory enforceable standards for BPS reliability developed by NERC, approved by FERC, and may be national or regional in applicability. Regional Reliability Standards are developed by Regional Reliability Councils (Appendix C) and must be more stringent than any applicable national Reliability Standard (NERC 2019a). In Order 693, FERC approved 83 of 107 Reliability Standards proposed by NERC, including some that were related to resource demand and balancing (BAL) and voltage and reactive controls (VAR), subjects closely tied to ERS provision (FERC 2007). 24 of the 83 Reliability Standards were approved by the Commission pending “significant improvement” (FERC 2007). NERC has updated, expanded, and/or deactivated many of these standards over the past decade, which has resulting in a flurry of orders from FERC administrating the approval process (Hilt 2018). A summary of NERC Reliability Standards related to generator interconnection and BPS reliability is presented in Appendix C.

Applicable Laws and Regulations cover a broad body of Federal, State, and Local requirements for generator facilities. Generators larger than 20 MW are usually interconnected to (>100 kV) transmission lines, which are usually considered to be in Interstate Commerce and part of the BPS. As such, these facilities are usually under Federal jurisdiction (with a notable exception being the Texas Interconnection) and interconnect via the LGIP. Additionally, Interconnection Customers must comply with other applicable laws and regulations such as federal wetlands and conservation laws, state-level environmental reviews (e.g., New York’s State Environmental Quality Review), and local zoning and ordinances. Smaller generators (i.e. up to 20 MW) need to comply with a similar scope of laws but may face more ambiguity over interconnection procedures depending on whether their point of interconnection (POI) is FERC-jurisdictional. Certain small generators interconnected to lower-voltage (i.e., ≤100 kV) distribution networks may sometimes be considered FERC-jurisdictional “Distribution Systems subject to an OATT” (FERC 2005b). All other distributed generation is under the jurisdiction of State Public Utility Commissions (PUCs).

2.4.3. Operational Norms for Wind & Solar

In the nearly forty years that utility-scale solar and wind have been part of the BPS, they have developed a reputation as must-take resources that are only controllable through crude curtailments (U.S. DOE n.d.; Greentech Media 2019). Since solar and wind generators do not consume fuel and have minimal operations and maintenance cost, their marginal cost of generation ($/MWh) is close to zero. So long as there is demand for electricity, it is always economical to generate that electricity using wind and solar plants. However, planning for power output from these resources, which varies temporally and spatially and is subject uncertain real-time metrological conditions, has proven to be more challenging than planning for conventional thermal resources and hydro. Without accurate VER forecasts, system operators have treated wind and solar as must-take resources, choosing to balance the system net demand with more predictable resources (e.g. natural gas combustion turbines). In cases of overgeneration, operators have used last-minute, crude curtailments of wind and solar, relying on other resources to fine-tune system balance. As a consequence of treating solar and wind output as uncontrollable, system reserve requirements had to be increased in certain BAs with large penetrations of solar and wind to reliably integrate variable output from these resources (Milligan et al. 2015).

3. TECHNICAL CAPABILITY

Wind and solar generation are variable and uncertain, often not fully dispatchable by the grid operator, and have different electromechanical characteristics than conventional generators. Despite the various connection approaches based on generation technologies, multiple techniques are available to obtain controlled power output from wind and solar generators that contribute to grid frequency and voltage support (Nerkar, Dhamal, and Sourish 2016). FFR techniques for both wind and solar PV are available, but due to the variability and uncertainty of wind and solar resources, this FFR capability is not recognized as FFR in the markets and regulation spaces (NERC 2018l).

There are several types of wind turbines with different ERS capabilities (Table 2). Broadly, they are divided between fixed-speed and variable-speed turbines. Today, most new wind turbines are either Type 3 or Type 4 variable-speed turbines (FERC 2016a)

Table 2. Wind Turbine Types and ERS Capabilities

Technology	Technology	Characteristic	ERS Capability
Type 1 Wind Turbine	Squirrel-cage Induction Generator	Fixed-speed/synchronous: turbine speed is fixed to the electrical grid frequency	Inertia; separate static voltage controls may be added to facility (e.g., shunt capacitors)
Type 2 Wind Turbine	Wound Rotor Induction Generator		Inertia; separate static voltage controls may be added to facility (e.g., shunt capacitors)
Type 3 Wind Turbine	Doubly-Fed Induction Generator	Variable-speed/non-synchronous with partial power electronics; AC-DC-AC frequency converter	AGC regulation, Synthetic inertia/fast-frequency response, primary frequency control, and power factor control
Type 4 Wind Turbine	Full-scale Converter Generator	Variable-speed/non-synchronous with full power electronics; AC-DC-AC frequency converter	AGC regulation, Synthetic inertia/fast-frequency response, primary frequency response, and power factor control
PV Solar	Thin-film or crystalline silicon module	Non-synchronous with full power electronics; DC-AC frequency converter	AGC regulation, Synthetic inertia/fast-frequency response, primary frequency response, and power factor control

Adapted from (FERC 2016a; Habash, n.d.; NERC 2016b, 2018l; Nerkar, Dhamal, and Sourish 2016; Wu and Gao 2017)

State-of-art frequency control techniques available for wind turbine have been documented by the research community and industry alike. Fixed-speed wind turbines are synchronous and can contribute to system inertia directly, although the response is different than that from conventional synchronous generators (Uski 2015). Variable-speed wind turbines are asynchronous and cannot contribute directly to system inertia without extra control mechanisms (Muljadi, Gevorgian, and Singh 2012).

Power electronics on modern wind turbine generators (Types 3 and 4) can respond to frequency deviations on the grid with injections of active power, including during timeframes that would traditionally be considered inertial response (Section 2.2.1). Also, the plant controller is capable of extracting kinetic energy from the turbine blades and generator rotors and injecting it into the grid (NERC 2016b; Wu and Gao 2017). This capability is often referred to as "synthetic inertia" and is considered a type of fast frequency response (NERC 2016b).

For conventional generators, PFR is provided by a mechanical governor that automatically controls power output rate according to deadband and droop settings (Section 2.2.1). Both wind turbines (Type 3 and Type 4) and solar can be economically equipped with power electronic controls that are capable of simulating governor-like response to a frequency disturbance (FERC 2018c). Supervisory wind farm control systems allow wind turbines to provide active and reactive power and contribute to primary and secondary frequency responses (Merz et al. 2018).

Power output from PV solar modules is in direct current (DC) so an inverter must be used to convert DC to AC before interconnection to the grid. The technical capability of smart inverters for solar PV has been elaborated clearly in the recent policy development in California. In 2017, California Public Utilities Commission (CPUC) updated the Electric Rule 21, an interconnection, operating and metering requirement for distributed generating resources, in which certain smart inverter capability is mandated ("Smart Inverter Working Group" n.d.). Although this rule applies to resources outside of the BPS, it helps to demonstrate that more responsive inverter settings are both technically and economically viable for solar, storage, and wind resources. The smart inverter requirement includes low and high voltage ride-through, low and high frequency ride-through (Section 2.2.3), ramp rate, fixed power factor control, and dynamic reactive power control (CPUC 2014). The rule is a preemptive action informed by Germany's experience from 2011 to 2014, during which about 400,000 PV systems were required to reconfigure inverters to prevent large-scale losses of generation at frequencies above 50.2 Hz (Boemer et al. 2011). The majority of the compliance was fulfilled through software updates and adjustments to settings, but the total cost was estimated to be between USD $88 to $238 million (NREL 2014).

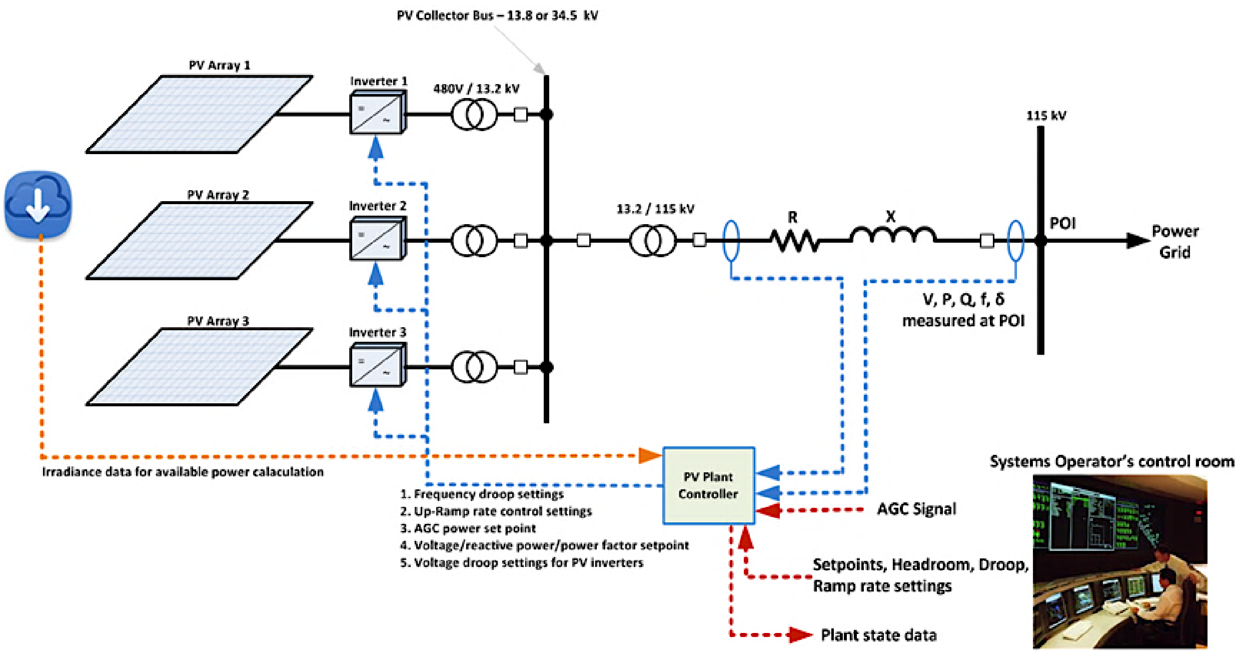
In summary, the available advanced inverter functions include voltage and frequency regulation, frequency and voltage ride-through, dynamic current injection, and anti-islanding.

3.1. Demonstrations of Capability from Solar Photovoltaic Power Plants

In recent years, three demonstrations conducted under the leadership of NREL have proven the ERS capabilities of utility-scale solar PV power plants (Loutan et al. 2017). The key component that enables these demonstrations to provide ERS is a programmed power plant controller (PPC) (Figure 14) (Gevorgian and O'Neill 2016; Loutan et al. 2017). During these demonstrations, researchers applied several tests to evaluate ERS performance. Specifically, they all conducted FFR tests, frequency droop tests, and AGC tests. FFR is a new technology that allows for an automatic response to a frequency deviation within the inertial and PFR timeframes. Frequency droop tests demonstrate that the plant's governor-like controls can accurately follow a droop curve setting (Loutan et al. 2017). FFR and frequency droop tests are used to evaluate inertial control and primary frequency control. The AGC tests shows the power plant's capability to follow dispatch signals from a system operator.

These demonstrations found that "all hardware component enabling PV power plants to provide a full suite of grid-friendly controls are already in existence in many utility-scale PV plants. It is mainly a matter of implementing controls and/or communications upgrades to fully enable these" (Gevorgian and O'Neill 2016; Loutan et al. 2017). However, it is noted that internal ramp rate settings limit the ERS performance of some PV plants (Gevorgian and O'Neill 2016; Loutan et al. 2017).

Figure 14. Grid-friendly PV power plant from NREL



(Gevorgian and O'Neill 2016)

3.1.1. AES's 20-MW Ilumina PV Power Plant Test Results

The demonstration for this power plant, which is located in Puerto Rico, was implemented from July 2015 to August 2015 (Gevorgian and O'Neill 2016).

For the FFR tests, the plant first curtailed 10% of its power output. Next, the PPC was scheduled to utilize curtailed reserve to counteract a drop in frequency (Gevorgian and O'Neill 2016). The result shows that the plant is able to provide fast frequency response within 500 milliseconds, which is much faster than a steam turbine and the typical gas turbine (Gevorgian and O'Neill 2016).

For the frequency droop tests, investigators conducted several 5% and 3% frequency droop tests. Before tests, 10% of the plant's output was curtailed and the PPC was set into droop mode with either a 5% or 3% droop value and a ±25-mHz deadband (Gevorgian and O'Neill 2016). The result showed that a ramp-rate limit of 4MW/minute caused poor droop performance during high solar resource variability periods (Gevorgian and O'Neill 2016). After removing the ramp rate limitation, droop performance improved (Gevorgian and O'Neill 2016). Droop performance was also found to be better during periods of lower solar resource variability (Gevorgian and O'Neill 2016).

During AGC tests, the power plant curtailed 20% or 40% of its estimated available peak power. For both 20% and 40% tests, the plant demonstrated good AGC performance (Gevorgian and O'Neill 2016). However, the AGC performance dropped dramatically during high solar power variability periods (e.g., cloudy days) because of out of control power plant production (Gevorgian and O'Neill 2016).

3.1.2. First Solar's 22-MW Pecos Barilla PV power plant

The Barilla PV Plant is in West Texas. This demonstration was conducted in September 2014 and August 2015 (Gevorgian and O'Neill 2016).

In addition to FFR tests, frequency droop tests and AGC tests, the demonstration also includes additional tests such as reactive power control tests and voltage control tests. Table 3 shows ERS tests for Barilla PV plant and their results. The overall performance of these tests is satisfactory. However, similar to Ilumina PV plant test results, the internal ramp-rate limit also had a negative impact on frequency droop response (Gevorgian and O'Neill 2016). Moreover, FFR performance is also limited by the internal ramp-rate (Gevorgian and O'Neill 2016).

Table 3. Tests for First Solar's Barilla PV Plant

Tests	Settings	Results
FFR tests	• Curtail about 50% power • In 30 seconds, deploy all reserve and then curtail to 50%	Took both 2.5 seconds to achieve peak production and curtail back to 50%. It is a fast frequency response. Performance negatively affected by the inverter ramp-rate limit
Frequency droop tests	• 1.67% droop setting • ±36-mHz deadband	Cannot provide desired droop response because of the inverter ramp-rate limit internal ramp-rate limit
Active power curtailment tests with power factor control	• 1-hour test during peak hours • Curtail production and ramp back to full production in accordance with the set point steps • Maintain 0.99 power factor	Good performance
Plant sequential shutdown tests while maintaining POI power factor	• Gradually shut down the inverters in 10 minutes • Maintain 0.99 power factor	Good performance
Reactive power control tests	• During peak hours • Provide reactive power according to set points	Took 4 seconds to settle steadily
Voltage control tests	• Controls were set to increase voltage at POI was (138-kV bus) by 1%, or 81 kV to 81.85kV	Took less than 1 second to settle at the new set point
Power factor control tests	• Change the power factor from 1 to 0.95 and -1 to -0.95 in accordance with commanded set points	With power rate limits, it took 30 seconds to achieve the commanded set points

Adapted from (Gevorgian and O'Neill 2016)

3.1.3. First Solar's 300-MW Solar Plant

Later, in Aug 2016, CAISO, First Solar, and NREL implemented a follow-up demonstration project in California to prove that a large utility-scale PV power plant could provide ERS. This demonstration test was conducted on First Solar's 300-MW PV power plant in CAISO's footprint (Loutan et al. 2017). Similar tests to the previous two demonstrations were conducted, but the results were more quantitative. According to this demonstration, with smart inverter technology and advanced power plant controls, PV "can provide essential reliability services related to different forms of active and reactive power controls, including plant participation in automatic generation control (AGC), primary frequency control, ramp rate control, and voltage regulation" (Loutan et al. 2017).

In frequency droop control tests, the plant curtailed 10% of its available estimated peak power and the PPC was set for droop control mode with either 5% or 3% droop values and a ±36-mHz deadband (Loutan et al. 2017). The active power ramp-rate limit was 600 MW/min (Loutan et al. 2017). Then the plant's frequency response performance was tested for simulated underfrequency and overfrequency events based on actual historical disturbances in the Western Interconnection (Loutan et al. 2017). Frequency droop control tests were also conducted during sunrise, midday, and sunset (Loutan et al. 2017). The researchers used relative droop control error to evaluate frequency droop control test results. The calculation method for relative droop control errors is as follows:

$$\Delta \mathrm{P}_{\mathrm{measured}}\ (\text{actual power response}) = \mathrm{P}_{\mathrm{actual}} - Estimated\ Peak\ Power$$

$$\Delta \mathrm{P}_{\mathrm{calculated}}\ (\text{target response}) = \frac{\text{Grid Frequency} - 60Hz}{60Hz} \times \frac{1}{Droop} \times Name\ Plate\ Capacity$$

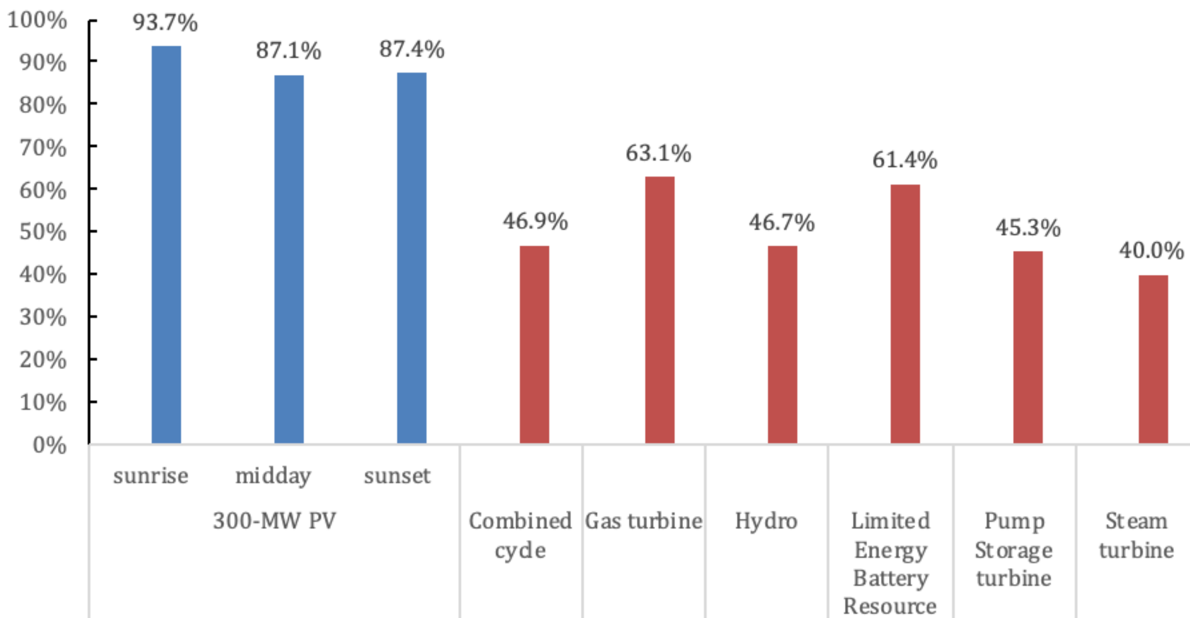
$$\text{Droop Control Error} = \Delta \mathrm{P}_{\mathrm{calculated}} - \Delta \mathrm{P}_{\mathrm{measured}}$$

$$\text{Relative Droop Control Error} = \frac{\text{Droop Control Error}}{nameplate\ capacity}$$

For the underfrequency event, test results show satisfactory droop performance, with low mean control error (from 0%-0.21% of the plant's rated capacity) and low standard deviation control error (0.07%-0.19% of the plant's rated capacity) (Loutan et al. 2017). The small differences between expected and actual droop response during the test can likely be explained by solar resource variability (Loutan et al. 2017). Frequency droop tests for the overfrequency events had similar results (Loutan et al. 2017). Based on the good performance of frequency droop control tests, investigators would like to test more aggressive droops (such as 1% or 2%) in the future (Loutan et al. 2017).

In the AGC participation tests, the plant controller was set to reserve 30 MW of headroom and AGC set point signals were sent every four seconds (Loutan et al. 2017). Since the plant did not have a solar irradiation estimate algorithm, investigators used one of the 80 inverters to estimate the AC power output from the other 79 inverters (Loutan et al. 2017). The AGC test was conducted 3 times (sunrise, midday, sunset) with each test lasting approximately 20 minutes (Loutan et al. 2017). The results show that the plant had good AGC performance and can closely follow dispatch set points. Small errors in dispatch might have been related to inverter ramp-rate limitations (Loutan et al. 2017). Notably, even during high solar resource variability periods (such as moving clouds), the plant had good AGC performance (Loutan et al. 2017). Moreover, based on AGC test results, the 300-MW PV plant's regulation accuracy was between 87.1% and 93.7%, which is 24-53 percentage points better than CAISO's typical conventional generation (Loutan et al. 2017) (Figure 15)

Figure 15. Measured Regulation Accuracy by 300-MW PV Plant and Typical Regulation-up Accuracy of CAISO Conventional Generation



Adapted from (Loutan et al. 2017)

In addition to AGC and frequency droop control tests, researchers also conducted reactive power tests, voltage control tests, curtailment control tests, and other APC tests (Loutan et al. 2017). The plant had good performance for all tests (Loutan et al. 2017).

3.2. Demonstration of Capability from Wind Power Plants

Researchers have found that inverter controls on variable-speed wind generation (Types 3 and 4) can provide PFR and inertial response (Section 3). In 2016, NREL conducted research to examine the capability of wind turbines to provide reliability services. Gevorgian and Zhang conducted a series of simulations and reached a conclusion that PFR and synthetic inertial response from wind greatly enhanced the reliability performance of the test system (Gevorgian and Zhang 2016).

Gevorgian and Zhang first determined the frequency metrics used to evaluate the performance of PFR of an interconnection: RoCoF, value of frequency nadir (Point C, Section 2.2.1), transition time, and value of settling frequency (Point D, Section 2.2.1) (Gevorgian and Zhang 2016). For their base case analysis, they used General Electric's (GE's) Positive Sequence Load Flow modeling software to estimate the overall frequency response in the Western Interconnection for different penetration levels of wind generation, absent of PFR and inertia controls. Four different wind turbine technologies were used in the simulation. Types 1 and 2 wind turbines (Table 2) were selected to provide inertial response to the system. Types 3 and 4 (Table 2) were included in the system to provide PFR (Gevorgian and Zhang 2016).

The simulation showed a marginal improvement in inertial response at low wind penetration. Allowing the wind turbines to contribute PFR also improved interconnection frequency response. However, the combination of inertial and primary frequency controls had the best performance, resulting in a significantly higher frequency nadir (Gevorgian and Zhang 2016). Wind ERS also impacted the frequency response of conventional generation (Gevorgian and Zhang 2016). According to Gevorgian and Zhang, frequency support from wind turbines can reduce the burden of frequency response on other conventional generators (Gevorgian and Zhang 2016).

Gevorgian and Zhang concluded from the simulation that the gird can benefit from inertial and PFR controls on variable-speed wind turbine generators (Types 3 and 4).

4. MARKET INNOVATION

4.1.1. Case Studies of U.S. Markets

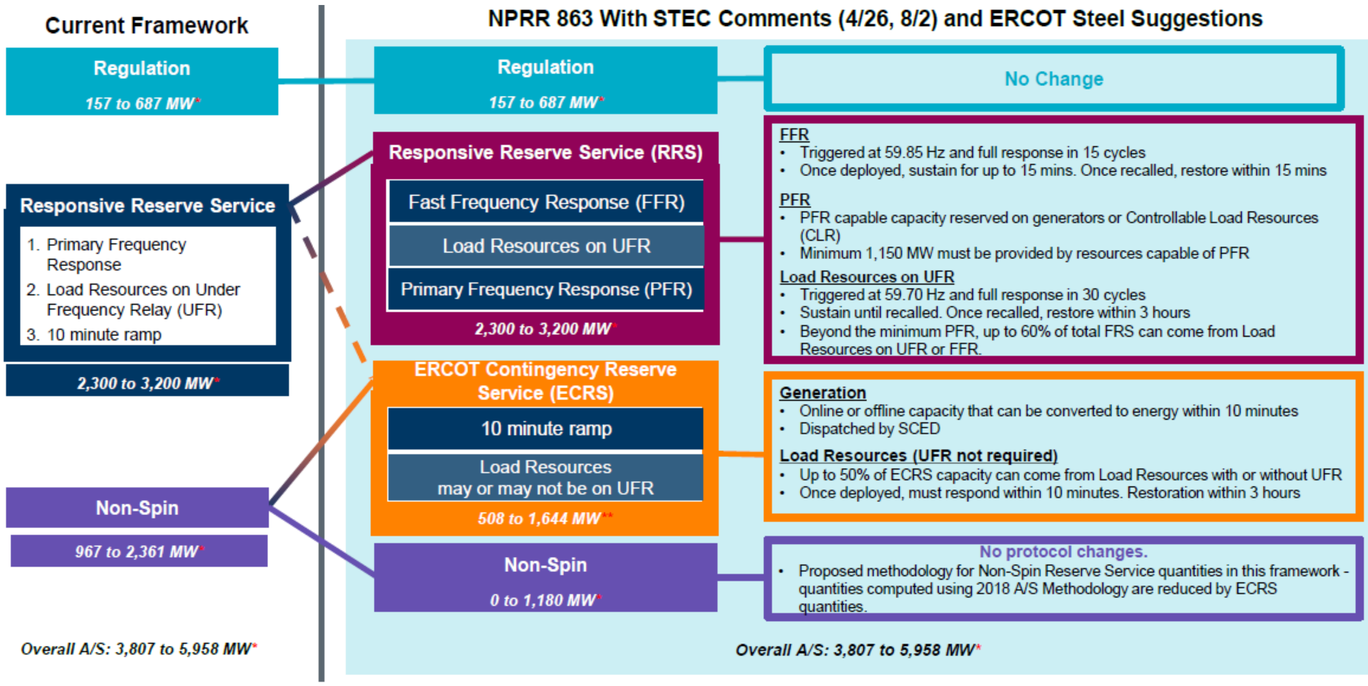
Regional grid and market operators have taken action to improve their operational and planning procedures to accommodate the growing penetrations of wind and solar within their territories. Since Electric Reliability Council of Texas (ERCOT), the Midcontinent Independent System Operator (MISO) and the Public Company of Colorado (PSCO) all have significant wind capacity, they have already implemented several strategies to mitigate ERS concerns. Therefore, their experiences provide good examples for other regions to follow.

4.1.1.1. Electric Reliability Council of Texas (ERCOT)

ERCOT serves more than 25 million customers in Texas, representing nearly 90% of the electric load in the state (ERCOT 2018a). It is noted that ERCOT has significant renewable energy penetration, primarily wind. In 2018, 18.6% of ERCOT's load was served by wind (ERCOT 2019b). In February 2019, it had 21,751 MW of installed wind capacity, which is the most of any other state (ERCOT 2019b). Its instantaneous wind penetration record is 56.16%, which was reached on January 19, 2019 (ERCOT 2019b). While the increasing wind penetration has presented integration challenges, ERCOT manages the reliability challenges using the following methods:

In 2018, ERCOT proposed to modify its ancillary service market. Specifically, ERCOT is planning to modify its Responsive Reserve Service and create a new ancillary service, ERCOT Contingency Reserve Service (Matevosyan 2018b). Figure 16 illustrates the proposed changes to ERCOT's ancillary service market.

Figure 16. Proposed Ancillary Service Framework Changes, 2018



(Matevosyan 2018b)

For primary frequency response, ERCOT requires all online generators (except nuclear) to have a governor in service with set droop and frequency deadband. Since 2012, PFR from governor-like controls has been required from intermittent resources, such as wind and solar (Matevosyan 2017). However, for wind power plants with interconnection agreements signed on or before January 1, 2010, ERCOT determines PFR requirements on a case-by-case basis (ERCOT 2019a). In 2016, the governor deadband requirement for all generators was reduced from ±0.034Hz to ±0.017Hz (Matevosyan 2018b).

In addition to standard ancillary services, ERCOT added a Reliability Risk Desk in January 2017 to improve management of increasing penetrations of variable generation. The Reliability Risk Desk's responsibility includes (Matevosyan 2018b):

- Monitor renewable production forecast and extreme weather,
- Monitor real-time inertia against critical inertia conditions and resulting responsive reserves requirements,
- Monitor sufficiency of non-spinning reserves, and
- Other tasks (e.g., minimize telemetry issues).

Also, ERCOT has improved its wind forecasting. In 2017, it added a secondary wind forecasting service. Two wind forecasting vendors help to improve the reliability and flexibility of the forecast process (ERCOT 2018a). Beginning in April 2018, ERCOT implemented intra-hour wind forecasting, which helps operators to better prepare for potential wind generation ramps at the 5-minute interval (ERCOT 2018a). This additional forecasting reduces the amount of reserves needed to balance the grid and increases the efficiency of the system (ERCOT 2018a).

4.1.1.2. Midcontinent Independent System Operator (MISO)

The Midcontinent Independent System Operator (MISO) operates the grid and power markets for parts of 15 states in the Midwest and the Southern U.S., and also a Canadian province (MISO 2019a). MISO also has significant wind penetration. As of February 2019, 15% of MISO's market capacity comes from renewable resources (MISO 2019a). Specifically, MISO has 19,252 MW of wind generation capacity, which accounts for 11.02% of MISO's market capacity (MISO 2019a). Registered solar generation capacity is only 312 MW, which represents 0.18% of MISO's market capacity (MISO 2019a). On January 8, 2019, MISO had a record instantaneous power output from wind resources of 16.3GW.

To protect against reliability issues from increasing VERs, MISO implemented the Dispatchable Intermittent Resource (DIR) protocol in mid-2011. The protocol "requires wind plants operating on or after April 2005 to bid into the real-time market" (Bird, Cochran, and Wang 2014). However, wind plants that "are QFs under PURPA that are not currently registered members of MISO" can be exempt from becoming DIRs (Project Finance NewsWire 2011). The protocol pushes wind plants to become dispatchable, which also improves their potential ERS capability. In February 2019, 87% of MISO's wind capacity was registered DIR capacity (16,729 MW) (MISO 2019b). The main advantage of DIRs is that they can be dispatched automatically, reducing the number of manual curtailments (Bird, Cochran, and Wang 2014) and increasing operational efficiency and transparency (Milligan et al. 2015).

4.1.1.3. Xcel/Public Service Company of Colorado (PSCO)

Xcel Energy is a VIU based in Minnesota that owns the PSCO (Xcel 2019). Wind energy is a local, clean, and affordable energy resource in Colorado (Xcel 2019). According to U.S. Environmental Protection Agency (EPA), PSCO had 31% wind generation and 1.6% solar generation in 2016 (USEPA 2018). Xcel Energy has a considerable wind capacity across its territory and partnered with NREL to improve its wind energy performance.

Wind power plants are capable of providing reliability services to PSCO's territory (Milligan et al. 2015). Because PSCO's resource mix is mostly coal and wind, PSCO had to decide whether to use coal or wind resources to balance the grid during periods of overgeneration (Milligan et al. 2015). PSCO found that the total system cost for both strategies were similar, but noted the benefit of using curtailed wind power for upward regulation services (Milligan et al. 2015). Curtailed wind power plants in the PSCO territory provide AGC regulation services using energy that would have otherwise been curtailed for regulation services (Milligan et al. 2015).

4.1.2. Case Studies of European Markets

4.1.2.1. Simulation-based Case Studies for Synchronous Regions in the European Union

Besides technology advancement in inverters and algorithms, operational innovation has continued to increase the system capacity to integrate variable and non-dispatchable resources. Meanwhile, the benefit of a large geographic footprint has also been recognized.

Several European countries have experienced rapid VER deployment in the past decade, such as Denmark, Germany, UK, Ireland and the Iberian Peninsula. In early 2018, the European Union (EU) pledged to source 34% of its annual generation from renewable resources by 2030 (International Renewable Energy Agency and European Commission 2018).

Market structures and regulation designed for conventional power generation resources cannot accommodate the technological improvement without corresponding changes. Structuring the ancillary services market to enable grid support services from solar PV and wind turbines has been a subject of research and policy discussion in European regions for several years. Although transmission grid operation is still a work-in-progress, simulation-based case studies for multiple EU synchronous regions have revealed several patterns of effects from VER providing different types of ancillary services.

A comprehensive study on VER providing ancillary services required by the grid code in EU countries was supported by the European Commission and conducted from 2012 to 2014 (Van Hulle, Holttinen, et al. 2014). The onshore wind, offshore wind, and solar PV of different scales and clusters providing frequency support, voltage support and system restoration has been investigated for capability, costs, and future needs (Van Hulle, Holttinen, et al. 2014). In September 2014, frequency and voltage support requirements for individual solar or wind farms had not yet been specified at the European level; in the meantime, the communication and control techniques for solar PV and wind turbines were not considered as fast enough at both plant and aggregation levels.

Table 4. Frequency Support Capability and Grid Code Requirement in 2014

Frequency Support Category	Definition	Wind	Small-scale PV (less than 500 kW)	Large scale PV
Frequency Containment Reserves (FCR)	Operating reserves that can activate within 30 seconds of frequency deviation; usually respond automatically	Technical capabilities available at site, but grid codes have not enabled the provision of such a service at any level	Technical capabilities were not implemented by farm operators and high implementation costs; improvements to frequency measurement techniques are necessary; grid codes have not enabled the provision of such a service at any level	Technical capabilities are partially available at site, Software upgrade might be accomplished at reasonable costs, but requirements were unclear and there was no communication protocol between transmission operators and PV sites that enable such a service
Frequency Restoration Reserves (FRR)	Operating reserves that can activate and provide the services after 15 seconds and up to 30 minutes after frequency deviation	Technical capabilities available at site and the capability was clearly defined in grid codes; most EU countries did not allow such a provision except Denmark	Same as FCR	Technical capabilities are partially available at site, software upgrade might be accomplished at reasonable costs; the provision of such a service was either not defined or not allowed by the grid codes
Replacement Reserves (RR)	Operating reserves that can activate after 15 minutes and up to an hour of frequency deviation	Same as FRR	Technical capabilities were not implemented by farm operators and high implementation costs; grid codes have not enabled the provision of such a service at any level	Same as FRR
Firm Frequency Response	Under grid operators' control, usually has a minimum delivery amount	The possible contribution was unclear; and no specification in most grid codes	Technical capabilities were not implemented by farm operators	Technical capabilities available at site; but there was no specification in most grid codes
Ramping	Appeared in several proposals	Technical capabilities available at site	The ability of accurate forecast is an issue	Technical capabilities available at site

Adapted from (Van Hulle, Holttinen, et al. 2014)

Onshore wind operation in Ireland, offshore wind in Northern Europe, and a combined effect of wind and solar PV on the Iberian Peninsula were the focus of regional studies completed by ReServiceS project. The ReserviceS study investigated the economics and technical capability of wind and solar to provide reliability support to the EU grid in order to aid in the design of markets for ancillary services (Bickley 2019). Based on EirGrid's (the Irish grid operator) prior simulation work and the Enhanced Operating Capability (EOC) proposed by EirGrid, the impacts of new types of ancillary services products, value estimation and cost allocation between the generators and the customers have been studied. Besides the frequency support products listed in Table 4, the Irish grid at that time was also considering the possibility of synchronous inertial response provided by different types of wind turbines with a system non-synchronous penetration of 75%. The installed capacity in the Irish model was varied between 0 MW to 7,000 MW to examine the total cost changes, and the enhanced ancillary services from both conventional plants and wind plants resulted in significant balancing costs saving (Gubina and Ucd 2013). Compared to a business as usual scenario, the addition of EOC reduced wind curtailment from more than 5% to below 1%, and the balancing costs were reduced by 26 million euro annually (Gubina and Ucd 2013).

The operation of AC connected offshore wind is slightly different because its point of interconnection is onshore and more distinct from the generation sites. The AC connected offshore wind was technically able to provide frequency response with active power control or synthetic inertia. Reactive power control was simulated considering the capability of transformer tap chargers, shunt compensation, and regional coordination of offshore wind clusters. The ReServiceS simulated a 10% system load and a 10% generation loss in the system. The delay in signal from the AC side to the DC side might be a potential challenge for both offshore wind active and reactive power control. The results clearly demonstrated the benefits of aggregating wind farms to provide ancillary services at their onshore point of interconnection (Gubina and Ucd 2013).

The Iberian system simulation was designed to examine the combined effects of wind and solar in a medium-size system that has limited interconnection with the central European system. The model tested different level of ancillary services participation from VERs and the results suggested an adequate frequency response capability with only a fraction of wind plants and no solar PV participating. Solar PV does not have a ramping limit—when the solar radiation is abundant, solar PV performed a faster response rate than wind farms in the simulation (Van Hulle, Rekinger, et al. 2014). Beside simulation data, the demonstration project data from Iberian Transmission Service Operators (TSOs) showed that using reactive power set points helped detect the reduction of wind generation capacity faster (Red Eléctrica de España 2013).

The European case study in ReServiceS project covered Germany, Poland, Netherlands, Belgium, France, Great Britain, Denmark, Norway, Sweden and Finland, and tested only primary and secondary frequency response capability (Kiviluoma et al. 2014). 32%, 42% and 50% VER penetration scenarios were modeled. The results showed that either enabling VER participation in primary and secondary frequency response or allowing sharing of frequency reserves amongst different countries brought similar stability and cost saving benefits. The regional coordination mode generated the greatest production cost savings for both Eastern and Western Denmark. High wind penetration areas in the simulation had higher gains (Kiviluoma et al. 2014).

Market and regulation updates were discussed according to the modeling results in ReServiceS. Payment methods based on different ancillary services properties were compared under the Irish wind model as proposed by the Irish TSOs (Gubina and Ucd 2013).

Table 5. The Initial Feasibility Assessment of VER Providing ERS

	Methodology	Pros	Cons
Capability	"Based on contracted capability and declared availability" (Gubina and Ucd 2013)	"Stable, predictable revenue: reduced uncertainty for providers" (Gubina and Ucd 2013)	Lack of differentiation, consumer may pay for more a redundant amount
Dispatch Dependent	Varied according to system needs	"Can be targeted to those providers that offer better value services" (Gubina and Ucd 2013)	"Payment revenues are more difficult to predict" (Gubina and Ucd 2013)
Utilization	Only paid when called upon	"May ensure existing investment capability is maintained at a high level of performance" (Gubina and Ucd 2013)	No payment for providing a service margin
Modified Capability	Capability and availability modified by each provider's average provision costs and performance reliability	Incentivizes efficient ancillary services provision	"Special cases need to be considered (pumped storage, energy limited generators)" (Gubina and Ucd 2013)

Adapted from (Gubina and Ucd 2013)

The study proposed several new ancillary services that utility VER generators are capable of providing during normal operation, including fast frequency response, ramping margin, and fast reactive current injection. There is a tendency in some markets to enhance the existing provision with shorter reactive time and longer service duration. The study has also revealed the distinctive regional system ancillary services demand because of different resource mix and geographic footprints. However, since 2009, the EU grid regulator, ENTSO-E, has gone through several steps to unify the baseline grid support services provided by EU regional transmission operators. In 2013, the EU commission released the first version of Requirements for Grid Connection Applicable to all Generators (ENTSO-E 2013).

Since changes to accommodate more flexible operation of wind turbines and solar PV on the transmission level have been implemented or tested over the last few years, the European Union (ENTSO-E) has undergoing another round of region-wide transmission grid monitoring and modeling under the project EU-SysFlex. Innovations in technology and operations combined with existing methods are being simulated to inform policy and market reforms to increase the system flexibility on the transmission level.

4.1.2.2. Regional European Union Grid Code Requirements

Interconnection agreements have been updated to reflect the technological and economic capability to some extent. There is an increasing number of countries and synchronous regions that apply the same minimum design and operational criteria for ERS to all generation technologies.

In recent years, the grid codes for frequency response capability and responsibility have been updated and relatively well defined for all generators including VERs. Primary frequency response has increasingly become a common and uniform requirement for both conventional and variable resources. The different technical specifications are more often defined by the sizes of the generators instead of the generation technology.

Table 6. ERS Requirement in the Grid Codes of EU Region

	Components	Operational Requirements	Technical Settings	Provision Mechanism and Payment	Applicability
Great Britain (UK National Grid Electricity System Operator Limited 2019)	Primary Frequency Response	"Primary response is provided within 10 seconds of events and sustained for a further 20 seconds" (Frey et al. 2019)	• "Have a 3-5% governor droop characteristic" (Paul Good 2015) • "Be capable to provide continuous modulation power responses to counter the frequency changes via synchronized generation through their automatic governing systems" (Paul Good 2015)	"Parties are paid a holding rate (£/MW/h) and an energy payment (£/MWh)" (Paul Good 2015)	In general, all units with a registered capacity 100MW (UK National Grid Electricity System Operator Limited 2019)
	Secondary Frequency Response	"Secondary response is provided within 30 seconds of an event and sustained for a further 30 minutes" (Frey et al. 2019)			
	High Frequency Response	"High frequency response is provided within 10 seconds of an event and can be sustained indefinitely" (Frey et al. 2019)			
Finland (Fingrid 2018)	Frequency controlled Disturbance Reserve (FCRD)	• Activation of this service begins when the frequency decreases below 59.9 Hz (Fingrid 2018) • Full reserve shall be activated at a frequency of 49.5 Hz (Fingrid 2018) • Half of the reserve shall be activated in 5 seconds and the full reserve activated in 30 seconds for a stepped frequency change of 0.5 Hz (Fingrid 2018)	• Frequency Response Insensitivity is less than10 mHz (Fingrid 2018) • Deadband is adjustable between 0 and 1 Hz in steps of a maximum of 0.01 Hz (Fingrid 2018) • Droop is adjustable between 2% and 12% in maximum steps of 1% (Fingrid 2018)	The capability is mandatory for eligible power plants with payment (Fingrid 2018)	All synchronous and wind power generating facilities larger than 10 MW (Fingrid 2018)

	Components	Operational Requirements	Technical Settings	Provision Mechanism and Payment	Applicability
Italy (Terna 2019)	Primary Frequency Control	• Units must reserve a minimum of ±1.5% of their maximum generation capabilities (Terna 2019) • Within 15 seconds from the beginning of a frequency change a unit must deliver at least half of the IIP requested (Terna 2019) • Within 30 seconds from the beginning of a frequency change a unit must deliver all of the IIP requested (Terna 2019) • Once activated, the unit must be able to continue to stably supply the required IIP for a minimum of 15 consecutive minutes (Terna 2019)	• 1) Frequency Response Insensitivity must be 10 mHz for all installations (Terna 2019) • Deadband requirement is ± 10 mHz for hydro units and steam simple cycle units (Terna 2019) • Deadband requirement is ± 20 mHz for gas turbine units and for steam units of combined cycles (Terna 2019) • Droop hydroelectric groups must be adjustable between 2-5% (Terna 2019) • Droop for thermal groups must be adjustable between 5-8% (Terna 2019)		All units with nominal power larger than 10 MVA, excluding those fed by non-programmable renewable sources (Terna 2019)
Ireland (EirGrid 2018)	Frequency Sensitive Mode (EirGrid 2018)	• Each generator shall have a Primary Operating Reserve (POR) of “not less than 5% Registered Capacity… in the range from 50% to 95%” of its registered capacity (EirGrid 2018) • POR is “the additional MW output (and/or reduction in Demand) required at the Frequency	• Deadband shall be set to 15 mHz (EirGrid 2018) • Droop shall be adjustable so that the unit has an overall droop of 3% to 5% (EirGrid 2018)	The capability is mandatory for eligible power plants with procurement through long term contract or auction (EirGrid 2018)	All generating units with registered capacity larger than 2 MW (EirGrid 2018)

	Components	Operational Requirements	Technical Settings	Provision Mechanism and Payment	Applicability
		nadir…where the nadir occurs less than 5 seconds or more than 15 seconds after the Event” (EirGrid 2018)			
Spain (Red Eléctrica de España 2011)	Primary Frequency Control	• Response shall be fully delivered within 15 seconds for a deviation < 100 mHz (Red Eléctrica de España 1998) • In case of deviation >100 mHz, 50% of the reserve must be delivered within 15 seconds, 100% of the reserve must be delivered before 30 seconds with a minimum linear delivery rate between 15 and 30 seconds (Red Eléctrica de España 1998)	• Frequency Response Insensitivity is 10 mHz • No intentional deadband • Droop should allow generator to vary its output by 1.5% for a frequency deviation of 200mHz (Red Eléctrica de España 1998)	The participation is mandatory for eligible power plants; Generators incapable of providing primary regulation must provide proof that they have procured their primary regulation obligation from another generating unit (Red Eléctrica de España 1998)	All generating units
Switzerland (Swissgrid 2017)	Primary Frequency Response		• Frequency Response Insensitivity is 10-30 mHz (Swissgrid 2017) • Deadband is adjustable between 0-500 mHz (Swissgrid 2017) • Droop is adjustable between 2-12% (Swissgrid 2017)	The participation is voluntary. Generating units must pre-qualify by verifying their primary control capability to participate in the tender; offer sizes are 25 MW per bid (Swissgrid 2013)	All generating units

EU regulation on frequency sensitive mode can be found in COMMISSION REGULATION (EU) 2016/631 of 14 April 2016 (EU 2016)
Adapted from (Paul Good 2015; Frey et al. 2019; UK National Grid Electricity System Operator Limited 2019; Fingrid 2018; Terna 2019; EirGrid 2018; Red Eléctrica de España 2011; Swissgrid 2017)

4.1.2.3. Updates to European Union Ancillary Services Market Design

Wind is utilized more often than solar PV in the European regional market to provide certain ancillary services. For example, In the Irish market, solar technologies (PV, thermal and concentrated solar) are yet to be allowed to participate in the ancillary services market, but wind technology is included in EriGrid's proven technology list for system ancillary services.

Table 7. Utilizing Wind and Solar Generators to privide Ancillary Services in The Irish Grid

Ireland DS3 System Services+A1:E1	Primary Operating Reserve	Secondary Operating Reserve	Tertiary Operating Reserve	Steady State Reactive Power	Dynamic Reactive Response	Fast Post Fault Active Power Recovery
Wind	√ (from 5 to 15 seconds corresponding to the Nadir Frequency)	√ (from 15 to 90 seconds during the frequency event)	√ (from 90 to 300 seconds during the frequency event)	√	√	√
Solar PV, solar thermal, and concentrated solar	currently not allowed to participate in the ancillary services auction					

Adapted from (EirGrid 2019, 2017)

This new ancillary services procurement procedure DS3 in the Irish wholesale market was initially proposed in 2011 and the first auction is expected to begin between May and September 2019, during which a contract for up to 140 MW of frequency response and balancing services by 2021 will be awarded (EirGrid, n.d., 3).

The reform of ancillary services and balancing markets can easily be found in other European regions. The UK National Grid started to test a new suite of enhanced frequency products that can replace primary, secondary, and high dynamic response (a continuous service to manage the second-by-second frequency change that can last indefinitely during an event) in mid-2017. Ultimately, the UK National Grid expects to realize day-ahead auction of fast frequency response products and implement long-term tenders for the procurement of flexible assets. A trial of weekly frequency response auctions for frequency dynamic response and frequency static response products will begin in June 2019 and will last for 24 months (Current-News 2018). Increasing market access for non-traditional providers including storage technologies, renewable generators, and demand side response (DSR) is a goal for the program (NationalgridESO, n.d.). Besides an open market mechanism, the UK National Grid has also introduced new forms of operation in the market, allowing the first aggregator company, Limejump, to participate in the balancing market as a virtual power plant (VPP) (S&P Global 2018).

To capture the benefits of larger footprint and more diverse generation mix, the EU envisions a more integrated electricity market on the European level. The guidelines for energy balancing market collaboration (EU 2017) were released in 2017 in preparation for future energy market collaboration. Under the EU guidelines for energy balancing market collaboration, transmission operators from Austria, Belgium, Denmark, France, Germany, the Netherlands and Switzerland established a "Frequency Containment Reserve (FCR) Cooperation" in early 2018 (FCR Corporation 2018). The Cooperation is designed as a weekly auction process and contains more than half of the FCR demand in the European markets, which is expected to have an annual transaction of 200 million euro (Elia 2017). Another pilot project of this kind is the Trans European Replacement Reserves Exchange approved by ENTSO-E in 2016 (ENTSO-E, n.d.) which covers 9 synchronous regions (France, Great Britain, Italy, Portugal, Spain, Switzerland, Czech Republic, Poland and Romania). The first phase of TERRE transaction is expected to happen during the fourth quarter of 2019 (UtilityWeek 2018).

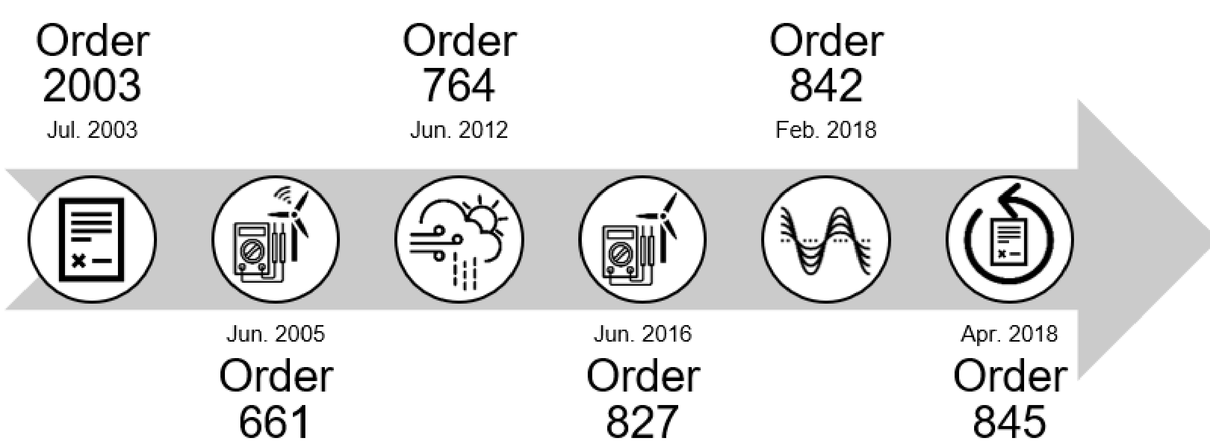
5. INTERCONNECTION REQUIREMENTS

5.1. Changes to FERC's pro forma Large Generator Interconnection Agreement and Procedures

The *pro forma* LGIA and LGIP set forth the minimum requirements and standardized approval process for Large Generating Facilities (i.e., larger than 20 MW) interconnecting to the U.S. BPS (Section 2.4.1). The following is a summary of FERC proceedings that have modified the LGIA or LGIP since its inception. Emphasis has been placed on the evolution of Large Generator interconnection requirements as they pertain to ERS and VER integration. Additional information regarding NERC Reliability Standards can be found in Appendix C.

Since FERC Order 2003, the Commission has issued five orders that have revised either the LGIP or LGIA, or both (Figure 17). These orders address dynamic reactive power factor control, primary frequency response, voltage and frequency ride-through, VER scheduling and operational visibility, and updates to the interconnection process. Order 661, which was issued in 2005, only applied to large wind generators because solar PV had not yet captured a significant share of the utility-scale market. Each of these orders only applies to newly interconnecting Large Generating Facilities.

Figure 17. FERC Orders that have Resulted in Modifications to the Order 2003 LGIA/LGIP



5.1.1. Dynamic Reactive Power Factor Control

Reactive power requirements in the *pro forma* LGIA have evolved since Order 2003 (Table 8). For a short period after Order 2003, large wind plants had the same requirement for dynamic reactive power factor capability range as all other generators, 0.95 leading to 0.95 lagging (Section 2.2.2). In a March 2004 Order on Rehearing (Order 2003-A), FERC exempted large wind generators this standard requirement, but added *Appendix G: Requirements of Generators Relying on Newer Technologies* (an empty placeholder) to the *pro forma* LGIA for future wind-specific requirements citing that “non-synchronous technologies, such as wind plants, may find that a specific [LGIA/LGIP] requirement is inapplicable or that a different approach is needed” (FERC 2005b).

In May 2004, American Wind Energy Association (AWEA) submitted a petition for rulemaking and a request for a technical conference on interconnection requirements for large wind plants (FERC 2005c). These proceedings resulted in Order 661, which added wind-specific reactive power requirement in Appendix G of the LGIA. Wind plants continued to be exempt from reactive power capability requirements unless the Transmission Provider’s (TP’s) System Impact Study showed that the capability was needed. In such cases, the wind plant would be obligated to provide the same reactive power capability as other large generators. There was some discussion on whether the measuring point for reactive power should be at the POI, as required for other Large Generators, or on the “high voltage side of the wind substation transformer” (FERC 2005c). There were industry concerns that providing reactive power factor support at the POI could be costly for wind farms with long generation tie lines (FERC 2005c). Ultimately, the Commission adopted the POI as the measurement point. Small wind plants interconnecting under the SGIP continued to be exempt from reactive power requirements at this time because they were expected to have a “minimal impact on the Transmission Provider’s electric system” (FERC 2005b).

A decade later, FERC issued Order 827, which again changed reactive power requirements for wind generators. This time, FERC’s order harmonized reactive power requirements for Large and Small Generators. Because utility-scale solar was slower to penetrate the resource mix than wind, it has always been subject to the reactive power requirements in Order 2003. The Order 827 modifications, which affected both the LGIA and SGIA, required that all generators interconnecting to the BPS have dynamic power factor capability within a range of 0.95 leading to 0.95 lagging. The rationale for the uniform requirements included the decline in inverter control costs and the risk of reactive power deficiencies from a growing penetration of wind generators (FERC 2016a). The reliability risk posed by changes resource mix, particularly from smaller distributed generators, is featured prominently in reports from the ERSTF (NERC 2015). Notably, with Order 827, reactive power requirements are no longer divided between wind and non-wind generators, but instead are bifurcated between synchronous and non-synchronous resources. The latter is inclusive of newer inverter-based resources, such as solar PV, wind, and electric storage devices. While FERC finds it reasonable to require the same dynamic reactive power capability range from both synchronous and non-synchronous generators, they recognize differences between the two generator types that warrant different power factor measuring points (FERC 2016a). Non-synchronous generators are required to provide dynamic power factor control at the high-side of the generator substation, while synchronous generators must provide the same capability at the POI.

Table 8. Changes to Order 2003 *Pro Forma* LGIA: Reactive Power Requirements for Non-synchronous Generation

Action	Date	Type	Reference	Summary
Order 2003	Jul. 2003	Original	Article 9.6.1: Power Factor Design Criteria	"Large generating Facility to maintain composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis." (FERC 2003)
Order 2003-A	Mar. 2004	Revision	Article 9.6.1: Power Factor Design Criteria	Wind plants are exempted Article 9.6.1 of the *pro forma* LGIA
		Addition	Appendix G: Requirements of Generators Relying on Newer Technologies	Empty placeholder
Order 661	Jun. 2005	Revision	Appendix G: Interconnection Requirements for a Wind Generating Plant	Renamed Appendix G
		Addition	Appendix G, Paragraph A.ii: Power Factor Design Criteria	"A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in [Article 9.6.1] of this LGIA, if the Transmission Provider's System Impact Study shows that the requirement is necessary to ensure safety or reliability." (FERC 2005c)
Order 827	Jun. 2016	Revision	Article 9.6.1: Power Factor Design Criteria	Non-synchronous generators must comply with Article 9.6.1 with a measuring point "at the high-side of the generator substation" (FERC 2016a). Synchronous generators must comply with Article 9.6.1 with a measuring point at the Point of Interconnection.
		Revision	Appendix G, Paragraph A.ii: Power Factor Design Criteria	Modified for consistency with updated Article 9.6.1

Adapted from (FERC 2003, 2004, 2005c, 2016a)

5.1.2. Primary Frequency Response

The Order 2003 *pro forma* LGIA and LGIP do not include requirements for primary frequency response capability for large generators. Declining frequency response has been a concern over the past fifty years, especially in the Eastern Interconnection (NERC 2012a). Recent retirements of synchronous generators with mechanical governor controls and their replacement by VERs with inverter-simulated governor controls led to even more concern about inertia and governor response following frequency disturbances. Recently there have been demonstrations (Section 3) showing the FFR capabilities of modern inverters to provide real power response within the traditional inertia and PFR timeframes. (NERC 2014). Another issue is assuring that governor response is sustained for a long enough time period to allow other resources to be dispatched by AGC to restore grid frequency (i.e. secondary and tertiary frequency response). A NERC survey in 2010 of generator owners and operators in the Eastern Interconnection found that only 30% of generators provided PFR and only 10% of generators provided sustained PFR (FERC 2018c).

With Order 842, FERC found that the costs of inverters that are capable of governor-like response has declined to a level where it is just and reasonable to require such controls on all new large generators (FERC 2018c). Order 842 modified Article 9.6 of the LGIA to include uniform minimum requirements for governor controls (i.e., maximum deadband and droop), requirements for timely and sustained frequency response, and resource-specific exemptions and qualifications (Table 9). These requirements help to establish a minimum level of ERS provision and address lingering issues of premature governor response withdrawal from new large generators.

Table 9. Changes to Order 2003 Pro Forma LGIP and LGIA: Primary Frequency Response

Action	Date	Type	Reference	Summary
Order 2003	Jul. 2003	Original	Article 9.6: Reactive Power	No reference to frequency response
Order 842	Feb. 2018	Revision	Article 9.6: Reactive Power and Frequency Response	Article title updated to include frequency response
		Addition	Article 9.6.4.1: Governor or Equivalent Controls	Uniform minimum operating requirements for governor controls • Maximum deadband: ±0.0036 Hz • Maximum droop: 5%
		Addition	Article 9.6.4.2: Timely and Sustained Response	Real power response must be provided automatically and to extent of the Large Generating Facility's operating capability
		Addition	Article 9.6.4.3: Exemptions	Exemptions from PFR requirements for nuclear and CHP resources
		Addition	Article 9.6.4.4: Electric Storage Resources	Requirements for PFR provision from electric storage resources between minimum and maximum state of charge

Adapted from (FERC 2003, 2018c)

5.1.3. Voltage and Frequency Ride-Through

The Order 2003 *pro forma* LGIA includes a provision for ride-through capability during under-frequency and over-frequency conditions (Article 9.7.3) and requirements to operate governors and voltage regulators automatically (Article 9.6.2.1). As described in Section 2.2.3, NERC Reliability Standard PRC-024-02 delineates “no trip zones” for generators during BPS voltage and frequency disturbances. Early wind plant technology utilizing simple induction generators was not capable of supporting Transmission System frequency or voltage, so wind generators were disconnected from the grid during power disturbances to avoid worsening the situation (Milligan et al. 2015). This approach became inadequate as wind plants increased in size and number and as technologies developed to support wind ride-through capability (FERC 2005c). Wind Low-Voltage Ride Through (LVRT) interconnection requirements became popular with both wind generator owners, who are incentivized to maximize power production, and TPs, who value consistent and robust ERS provision to their Transmission System. As discussed in Section 5.1.1, in May 2014 AWEA filed a petition for rulemaking and request for a technical conference on standards for the interconnection of wind, which resulted in Order 661 (FERC 2005c). Order 661 created a wind-specific LVRT time-duration curve to Appendix G of the LGIA. LVRT capability from large wind plants is only required if the TP’s System Impact Study finds it to be necessary (Table 10). Because utility-scale solar was slower to penetrate the resource mix than wind, it has always been subject to the ride-through capability requirements in Order 2003.

One year later, Order 828 required interconnecting small generators to have similar frequency and voltage ride-through capability to large generators (FERC 2016b). This action continues the trend in LGIA and SGIA harmonization observed for reactive power requirements (Section 5.1.1), and is driven, in part, by the reliability risk posed to the BPS by growing a penetration of DERs that was identified by the ERSTF (NERC 2015; FERC 2016b).

Table 10. Changes to Order 2003 Pro Forma LGIP and LGIA: Voltage and Frequency Ride-Through

Action	Date	Type	Reference	Summary
Order 2003	Jul. 2003	Original	Article 9.7.3 Under-Frequency and Over Frequency Conditions	"Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure *ride through* capability of the Transmission System." (FERC 2003)
			Article 9.6.2.1 Governors and Regulators	Large generators must set governors and voltage regulators to automatic operation
Order 661	Jun. 2005	Addition	Paragraph A.i: Low Voltage Ride-Through Capability	Technology-specific LVRT time duration curve for large wind generators, if LVRT is deemed necessary by the TP's System Impact Study

Adapted from (FERC 2003, 2005c)

5.1.4. VER Scheduling and Operational Visibility

Since Order 2003, the Commission has issued two Final Rules modifying the LGIA to improve VER scheduling and operational visibility (Table 11). Order 661 requires large wind plants interconnecting with the BPS to have Supervisory Control and Data Acquisition (SCADA) systems that can transmit and receive instructions from the TP. These data may be used to model and forecast wind output and ramp rate and further improve dispatch procedures (FERC 2005c). However, Order 661 does not authorize the TP to control the wind plant (FERC 2005c). The LGIA does not have the same SCADA requirements for utility-scale solar plants. Order 764 modifies the LGIA to require VERs meteorological and forced outage data to the TP to improve forecasts for power production. Improved forecasting allows TPs to "manage the variability of VER generation through the unit commitment and dispatch process, rather than the deployment of reserve service, such as regulations reserves which can be more costly" (FERC 2012). Order 764 also requires TPs to offer intra-hourly scheduling, which allows VERs to schedule generation that more closely matches their variable output, helping to mitigate imbalance fines and reliability issues.

Table 11. Changes to Order 2003 Pro Forma LGIP and LGIA: VER Scheduling and Operational Visibility

Action	Date	Type	Reference	Summary
Order 2003	Jul. 2003	Original	Not Applicable	No SCADA or meteorological data requirements
Order 661	Jun. 2005	Addition	Appendix G, Paragraph A.iii: SCADA Capability	Large wind plants must have SCADA systems capable of transmitting and receiving instructions from the TP
Order 764	Jun. 2012	Addition	Article 8.4 Provision of Data from a Variable Energy Resource	Large wind and solar plants (and other VERs) must provide meteorological and forced outage data to the TP to aid with power production forecasting

Adapted from (FERC 2003, 2005c, 2012)

5.1.5. Interconnection Process

Order 845 included ten revisions to the LGIP and LGIA intended to improve the interconnection process for ICs and update the definition of “Generating Facility” to include storage (FERC 2018d). Similar to Order 661, many of the Order 845 revisions were initiated by an AWEA petition and follow-on technical conference in May 2016. None of these revisions directly affect the ERS reliability building blocks.

5.2. Recent FERC Orders Affecting Large Generator Interconnection Requirements

The capability and responsibility of VERs in energy balancing have become more recognized among energy regulators as well as the industry through VER integration studies on interconnection level, utility-scale demonstration projects, and real operational cases. The changing expectations for wind and solar generators, and the potential capabilities of emerging technologies such as battery storage, have been accommodated in recent FERC Orders.

5.2.1. FERC Order 841

Electric storage has long been recognized for its potential to mitigate the variability and uncertainty of VERs (NREL 2010). On February 15, 2018, FERC issued Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators* to establish the role of energy storage in the markets (FERC

2018b). This rule applies to all storage technologies at the transmission and distribution levels or behind-the-meter (FERC 2018b). Under this rule, storage technologies are allowed to provide all technically feasible capability, including ancillary services, to wholesale markets. The rule took effect after 90 days after publication in the Federal Register (FERC 2018b). RTOs and ISOs were asked to submit their compliance filings no later than 9 months after Order 841 went into effect, with an additional year to implement tariff revisions (FERC 2018b).

According to Order 841, each ISO and RTO should revise their tariffs to ensure the full penetration of energy storage resources in their market. The rule also requires each ISO and RTO to establish their own participation model to ensure that energy storage is eligible to offer energy, ancillary services, and capacity (FERC 2018b). The rule recognizes that storage technologies are capable of a diverse set of ancillary services that are not typically allocated by market mechanisms; these include black start capability, primary frequency response, and reactive power services (FERC 2018b). In addition, FERC asked the markets to price storage using the same rules that apply other energy resources, meaning that energy storage would participate in the market both as a wholesale buyer and wholesale seller. Order 841 also requires that the markets sell power from energy storage resources at the locational marginal price (FERC 2018b). Finally, the minimum eligibility threshold for market participation of electric storage resources must not exceed 100 kW (FERC 2018b).

All ISOs and RTOs within the U.S. submitted their compliance filings before the deadline set by FERC (December 3, 2018). The organizations have revised both physical and operational requirements for storage. A minimum capacity requirement (100kW) to participate in the wholesale electricity market has been added into tariffs. In addition, some ISOs and RTOs have established payment exemptions for energy storage resources. According to ISO New England (ISO-NE), energy storage facilities will not pay the regional network service fee (ISO-NE 2018). CAISO also provides access charge relief to storage resources (e.g., Non-generator resources and Pumped-Storage Hydro Units) that are capable of withdrawing energy for later resale in the CAISO market or to provide ancillary service to the grid (CAISO 2018b). Also, operational and market rules have been revised. MISO has revised its Energy Storage Resource Offer Rules for both the Day-Ahead Market and Real-Time Energy and Operating Market (MISO 2018b). New York Independent System Operator (NYISO) also revised its market settlement process, bid parameters, and additional parameters for energy storage resources (NYISO 2018).

5.2.2. FERC Order 842

On Feb. 15, 2018 FERC issued Order 842 *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, which revised requirements on the provision of PFR, requiring all newly interconnected generating facilities to "install, maintain, and operate a functioning governor or equivalent controls capable of providing primary frequency response" (FERC 2018c). The driving forces for this rule revision include long-term downward trends of frequency response performance (Section 6.1), ongoing changes to the BPS resource mix (Section 2.3.2), and sufficient technology advancement (FERC 2018c). Four years prior to Order 842, NERC stated that "increasing levels of nonsynchronous resources installed without controls that enable frequency response capability, coupled with retirement of conventional generating facilities that have traditionally provided primary frequency response" had contributed to declining frequency response services nationwide (NERC 2014). According to FERC, the cost of providing primary frequency response has become "just and reasonable" (FERC 2018c). For example, the average cost of governors for a new utility-scale wind or solar generators would be $3,300/MW, or about 0.2% of total capital costs (FERC 2018c).

In Order 842, FERC asserts that equipment manufacturers have made impressive technological improvements in the primary frequency response capability of VERs, but these improvements had not yet been incorporated into existing FERC interconnection requirements (FERC 2018c). FERC also noted that existing rules did not specify governor deadband and droop (Section 2.2.1), two fundamental governor settings that impact primary frequency response (FERC 2018c). FERC revised primary frequency response rule by requiring a droop setting less than 5% and a deadband less than ±0.036 Hz (FERC 2018c). No distinction between large and small generators was made since FERC found "no economic basis to treat large and small generating facilities differently" (FERC 2018c). FERC chose not to impose a headroom requirement (FERC 2018c).

Exemptions and special accommodations were made in FERC Order 842. For instance, nuclear generators are exempt from the rule (FERC 2018c). Combined Heat and Power (CHP) generators sized to serve onsite load with no capability to export power to the grid are also exempt from the rule (FERC 2018c). Energy storage is only required to provide frequency response within specified operating ranges representing minimum and maximum state of charge (SOC) (FERC 2018c).

The final rule was made effective on May 25, 2018. In their compliance filings, ISOs and RTOs have made revisions to their LGIA and SGIA to implement new requirements for primary frequency response (FERC 2018c). Organizations have slightly modified the *pro forma* language to fit their LGIA and SGIA in cases where the organization uses different terminology to describe the same matter. Organizations also refined other documents in addition to LGIA and SGIA. ISO-NE proposed revision for both the LGIP and SGIP (ISO-NE 2018). PJM is different because they use a single interconnection service agreement (ISA) for both large and small generation. However, PJM stated that their single interconnection agreement satisfies the FERC standard because it applies PFR requirements to both small and large generators (PJM 2018a).

5.2.3. FERC Order 845

On April 19, 2018, FERC issued Order No. 845, *Reform of Generator Interconnection Procedures and Agreements* (FERC 2018d), which encourages developers to install storage resources with existing generators (FERC 2018d). Under this order, FERC updates the definition of “Generating Facility” to include electric storage resources (FERC 2018d). Also, the order permits ICs to request interconnection service at levels lower than their maximum power output so long as the IC ensures that the facility does not generate above the requested interconnection service level (FERC 2018d). For example, when developers install energy storage capacity at an existing generating facility, it’s unlikely that the retrofitted facility will inject power above the previous interconnection service level. Therefore, under the Order 845, they could avoid paying for unnecessary interconnection facilities and upgrades, resulting in lower interconnection costs for developers (FERC 2018d). Another reform that may benefit storage is the utilization of surplus interconnection service (FERC 2018d). If the IC doesn’t want to use the surplus capacity, then a transparent solicitation process can be used to offer the interconnection service to other customers (FERC 2018d).

Order 845 took effect on July 23, 2018, 75 days after it was posted to the Federal Register. All ISOs and RTOs were required to submit their compliance filings to FERC within 90 days (no later than Aug 7, 2018). However, on May 17, 2018, the ISO/RTO Council requested that the compliance period be extended by 70 days to October 16, 2018 (MISO 2018a). According to MISO, an extension was necessary to accommodate internal and stakeholder processes, which were expected to take longer than 90 days because of the large number of reforms (MISO 2018a). After receiving 12 requests for rehearing and clarification on Order 845, FERC issued

Order No.845-A on February 21, 2019 and postponed the compliance deadline to May 2019. The Draft Order adopted ten reforms to improve IC certainty and also granted two clarifications regarding study models and assumption transparency (FERC 2019). Each public utility transmission provider should submit their compliance filing on the Draft Order by May 22, 2019 (FERC 2019). As of March 2019, only PJM and ISO-NE have made public updates on their compliance with FERC Order 845 (PJM 2018b).

6. THE NERC SUBCOMMITTEES ON ESSENTIAL RELIABILITY SERVICES

Over four years, the ERSTF and ERSWG created a framework to measure, evaluate, and communicate reliability challenges of the modern grid. They did not conduct this work in a vacuum—between 2014 and 2018, the resource mix changed, technologies evolved, and Federal energy policy objectives shifted dramatically. Despite the instability, the group kept their scope and methods flexible while providing durable recommendations to ensure the BPS reliability and advance ERS awareness (Appendix B). The group's findings were rooted in the early identification of reliability challenges, resource provision of ERS at full technical capability, and acknowledgement of regional differences in ERS needs (Abdel-Karim et al. 2015).

After establishing the conceptual foundation of ERS, the groups developed Measures (Table 12) and proposed Sufficiency Guidelines (SGs) at the Interconnection and BA scales. The working group conduced initial data collection efforts and proof-of-concept for their proposed metrics (Appendix B). Based on this study process and input from stakeholders, the working group effectively refined their scope to focus on inertia and frequency response in the four interconnections and BA ramping adequacy. Other ERS Measures of BA frequency support (Measures 3 and 5) were found to have little value because frequency is an interconnection-wide phenomenon and BA frequency response performance is already tracked by Frequency Response Obligations (FROs) in accordance with Reliability Standard BAL-003-1.1 Frequency Response and Frequency Bias Setting (Appendix C) (NERC 2018d). The ERSWG also discontinued BA-level metrics related to voltage support (e.g., Measure 7) and advocated for a local approach to managing voltage issues consistent with Reliability Guideline: Reactive Power Planning and existing frameworks for interconnection studies, planning assessments, and operational studies (NERC 2017c).

Table 12. Status of ERS Measures and Industry Practices

Reference	Title	Scale	Type	ERSWG Recommended Outcome
Frequency				
1	Synchronous Inertial Response	Interconnection	Measure	Ongoing Quarterly Analysis by NERC RS (NERC 2018b)
2	Initial Frequency Deviation Following Largest Contingency or Rate of Change of Frequency $(RoCoF)_{0.5}$	Interconnection	Measure	Ongoing Annual Analysis by NERC RS (NERC 2018b)
3	Synchronous Inertial Response	BA	Measure	Discontinued March 2018 (NERC 2018c)
4	Frequency Response at Interconnection Level	Interconnection	Measure	Ongoing Quarterly Analysis by NERC RS (NERC 2018b)
5	Real Time Inertial Model	BA	Industry Practice	Adoption as Industry Practice; *Implemented by ERCOT and CAISO* (NERC 2015)
Ramping				
6	Net Demand Ramping Variability	BA	Measure	Ongoing Quarterly Analysis by NERC RAS (NERC 2018f)
Voltage				
7	Reactive Capability on the System	BA	Measure	Discontinued June 2017 (NERC 2017c)
8	Voltage Performance of the System	N/A	N/A	No Further Action
9	Overall System Reactive Performance	BA	Industry Practice	Adoption as Industry Practice
10	System Strength	Planning Coordinator	Industry Practice	Adoption as Industry Practice

Adapted from (NERC 2015)

In June 2018, NERC’s Operating Committee (OC) and Planning Committee (PC) voted to disband the ERSWG citing that the group’s work items had either been completed or transitioned to other groups (NERC 2018i). The ERSWG did not release the final report on Sufficiency Guideline that was part of their original scope, but instead released a series of detailed briefs between May 2017 and March 2018 that provided further refinement of select

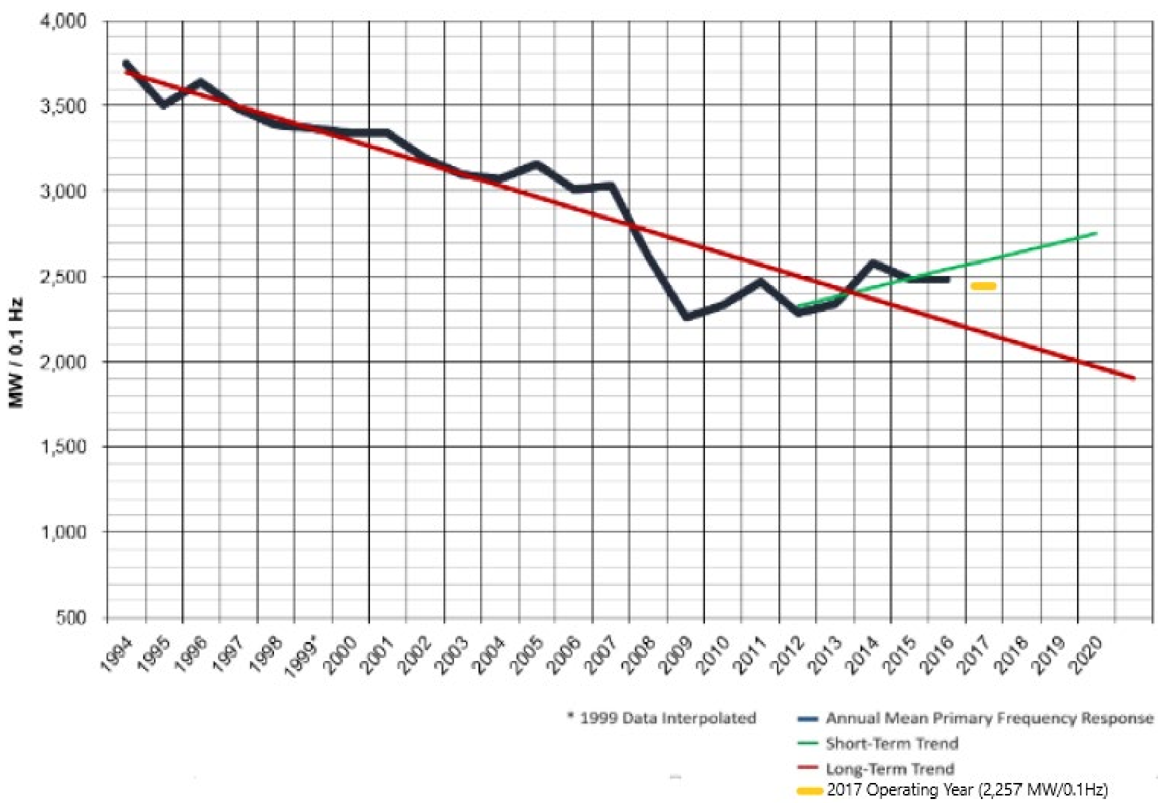
Measures and clarified the responsibilities and schedule for data collection and analysis. As detailed in Appendix B, aspects of Measures 1, 2, 4, and 6 have been incorporated into NERC Annual State of Reliability (SOR) and Long-term Reliability Assessment (LTRA) reports. The ERS framework provides useful quantitative measures as well as a conceptual framework that has aided in the communication modern BPS reliability challenges. In the months leading up to the work groups' conclusion, and shortly thereafter, there have been signs that the ERS framework and Measures have been adopted by other NERC subcommittees and the broader the regulatory and policy community.

6.1. Current State of ERS in the BPS

Since 2014, FFR from wind and solar resources has become integrated with NERC's tactics for assuring adequate inertia within the four interconnections. In their conceptual framework, the ERSTF described synthetic inertia as "new" and needing of examination by industry and device manufactures (NERC 2014). Much of the ERSWG's formulation of SGs was based the notion that low synchronous inertia conditions brought about by changes to the resource mix were a critical test case for initial RoCoF (Measure 2) and overall frequency performance (Measure 4) following a disturbance. As such, real-time synchronous inertia (Measure 3) is measured in all four interconnections and reported in NERC's LTRA report (Appendix B). In the last few years, operational experience, industry demonstration, and simulations have shown that FFR is capable of supplementing synchronous inertia (Loutan et al. 2017; Milligan et al. 2015). In this same time period, NERC's confidence in FFR to provide meaningful frequency support arresting phase of a disturbance has increased to the point where "the application of FFR is expected to continue and support frequency when synchronous inertia is insufficient" (NERC 2018m)

The ERSWG's efforts to track and trend interconnection frequency response performance (Measures 2 and 4) fit into a long-term effort to address degradation of interconnection frequency response that were first observed in the 1970s and 1980s in the Eastern Interconnection (NERC 2012a). A few years ago, the retirement of conventional generation equipped with mechanical power controls and their replacement by VERs with power electronics capable simulated governor response led to uncertainty and concerns over further PFR degradation (NERC 2014). Recent positive outlook on frequency response in all four interconnections comes from a confluence of increasing operational and planning experience with VERs, regulatory progress, and advancement in modeling capabilities. In each case, the progress has been supported by the findings and recommendations of the ERSWG. The ERSWG offered revamped measures and procedures for monitoring historical and forward-looking trends in frequency response (Appendix B). The result has increased confidence in the smaller interconnections' (TI and QI's) capability to use operational intelligence to manage PFR in real-time along with efforts to improve frequency response modelling of large interconnection (NERC 2018m). As described in Appendix B, NERC's most recent annual SOR report found that stabilizing frequency response ($IFRM_{A\text{-}B}$, Appendix B.1) was increasing in the WI and TI, but neither increasing nor declining in the EI or QI (NERC 2018h). Figure 18 shows the long-term trend of this metric in the Eastern Interconnection.

Figure 18. Eastern Interconnection Frequency Response Trend



Adapted from (NERC 2017f, 2018h)

NERC has also implemented forward-looking BA ramp capability assessment in their annual LTRA, consistent with the approach described in an ERSWG's technical brief and ERS Measure 6 (NERC 2018e). In 2018, NERC Reliability Assessment Subcommittee (RAS) identified ERCOT and CAISO as areas of interest for ramping analysis. The ramp capability assessment for ERCOT is focused on net-load ramps caused by high wind generation in the early spring mornings, where the balancing area has historically faced upward ramps of 11 GW (NERC 2018m). ERCOT has taken steps to improve wind forecasting to mitigate ramps and has self-funded research on wind net-load ramps to inform future planning processes (NERC 2018m). NERC appears to defer to the ERCOT's action on ramping challenges and does not present its own forward-looking analysis and notes that ERCOT's ramp requirements can be "largely managed with improved forecasting" (NERC 2018m). The ramp capability assessment for CAISO notes that the current maximum 3-hour upward ramp of 14 GW is attributed to an influx of solar DERs that has exceeded earlier projections (NERC 2018m). Revised maximum 3-hour ramp projections through 2021 are presented. In both cases, NERC concludes that increasing penetrations of VERs will necessitate the addition of more flexible capacity to reduce net-load variability (NERC 2018m). This flexibility can come in the form of increasing geographic diversity of resources and load, as is seen in CAISOs Energy Imbalance Market (EIM), or the addition of dispatchable generation (conventional or variable), dispatchable loads, and energy storage (NERC 2018m).

6.2. Policy Influence of the ERS Framework

A key aspect of the ERSWG and ERSTF's work was to advance the understanding of emerging reliability challenges to enable policymakers and industry to take proactive action to assure the reliability of the grid (NERC 2016b). Beyond technical reports and guidelines, the working group released briefs for policymakers and a series of educational videos on ERS that can be easily viewed on popular online video sharing website (NERC 2016a). NERC, FERC, and Department of Energy (DOE) proceedings have been analyzed to assess the radius of influence of the ERS framework.

In their 2017 workplan, the ERSWG stated that their SG work may lead to the development of Reliability Guidelines or Reliability Standards through the NERC Standard Authorization Request (SAR) process (NERC 2017b). As of February 2019, there have been no Reliability Standards or Guidelines developed that are directly related to ERS SGs. However, there has been some work to revise Reliability Standards related to frequency support. Two SARs calling for revision to *BAL-003-1.1 Frequency Response and Frequency Bias Setting* are expected to be completed by May 2019 (NERC 2018k). This Reliability Standard establishes a method for calculating FROs for individual BAs (NERC 2019b). The BA Frequency Response Obligation a portion of the overall Interconnection Frequency Response Obligation (IFRO), which is the amount of interconnection frequency response (MW/0.1Hz) needed to avoid the first level of UFLS (NERC 2019b). A third SAR was initiated after FERC directed NERC to revise *BAL-002-2(i) Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event*. This Reliability Standard ensures that BAs restore balance between generation with load following a contingency event by requiring that the BA's Area Control Error (ACE) is within certain bounds (NERC 2019b). The modification addresses MW losses over the Resource Contingency Criteria (RCC) and delays in ACE recovery and contingency reserve following a disturbance (NERC 2017g). The RCC usually refers to the interconnection disturbance event caused by the loss of the two largest resources (N-2) (NERC 2019b). These Reliability Standard revisions have been adopted by NERC and are awaiting FERC approval. Refer to Appendix C for more background information on these Reliability Standards.

However, NERC's OC and PC have released two Reliability Guidelines that expand beyond the ERSWG's work. In November 2018, NERC released a draft update to their *Reliability Guideline: Primary Frequency Response* that provided recommendations to industry on governor deadband and droop settings to complement regional requirements (e.g., BAL-001-TRE-1 and PRC-001-WECC-CRT-2) and baseline requirements for new generation set forth in FERC Order 842 (NERC 2018l). The second, *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*, was released in September 2018 and is based upon industry research conducted by NERC's Inverter-Based Resource Performance Task Force (IBRPTF). Similar to ERSWG, the IBRPTF is a subcommittee of the NERC OC and PC that is charged with understanding performance characteristics of inverter-based resources (e.g., PV, wind, and battery electric storage systems (BESS)) to ensure BPS reliability (NERC 2017e). The guideline is a highly technical review of the abilities and limitations of power electronic controls to respond to abnormal grid conditions along with NERC recommendations for reliability performance of IBR (NERC 2018j). All recommendations of the guideline are rooted in the first principle that "regardless of the type of resource, it is paramount that all BPS-connected resources are capable of providing ERSs and operate in a manner that supports BPS reliability" (NERC 2018j). The IBRPTF is currently authoring a new guideline and contributing to IEEE standards development on interconnection requirements for BPS-Connected Inverter-Based Resources (NERC 2019c).An outlook on this group's activity is presented in Section 7.2.2.4.

The work of the ERS subcommittees has been referenced explicitly and implicitly in FERC's proceedings over the past few years. FERC Order 842, which was issued on February 15, 2018, is entitled *Essential Reliability Services and the Evolving Bulk-Power System—Primary*

Frequency Response. ERS is featured prominently in the title of the order and the task force's work is cited to support mandating primary frequency response capability and minimum operating requirements. Order 842 is further discussed in Section 5.2.2.

The following FERC proceedings occurred while the ERS subcommittees were active and are related to the ERS framework and, in some cases, cite the group's findings:

- Order No. 819 issued November 20, 2015, *Third Party Provision of Primary Frequency Response Service*: This rule removes restrictions on the sale of PFR by third-parties (i.e., an entity other than the Transmission Provider) (FERC 2015b). The Commission cites the BA minimum FRO requirements set forth by BAL-003-1.1 (Appendix C) as a motivation for increasing competition for primary frequency response provision, which has the potential to broadly improve frequency performance, a key ERS consideration (FERC 2015b).
- Order No. 827 issued June 16, 2016, *Reactive Power Requirements for Non-Synchronous Generation*: As discussed in Section 5.1.1, this rule requires that new non-synchronous resources provide reactive power to the BPS, effectively eliminating previous exemptions for large wind generators (FERC 2016a). This rule expands provision of ERS, and is aligned with the ERSTF recommendation that "all new resources have the capability to support voltage and frequency" (NERC 2015).

In 2017, the DOE used the ERS framework to help advance a policy agenda supporting fuel-secure resources. In their August *2017 Staff Report on Electricity Markets and Reliability*, the U.S. DOE recommended policy development on the "valuation of Essential Reliability Services" (U.S. DOE 2017a). The timing of this recommendation is significant considering that a month later the Secretary of the Department directed FERC to issue a rule to ensure that "certain reliability and resilience attributes of electric generation resources are fully valued" by compensating fuel-secure resources capable of withstanding a 90-day disruption in fuel supply (U.S. DOE 2017b). The Secretary asserted that payments were necessary because the "resiliency of the electric grid is threatened by premature retirements" and "more work needs to be done to preserve these fuel-secure generation resources that have the essential reliability and resilience attributes needed to keep the lights on for all Americans in times of crisis" (Perry 2017). Since coal and nuclear power plants are the only resources with 90-day fuel storage capability, many viewed the action as an attempt to bailout industries facing competition from cheap natural gas and renewables (St. John 2018). In January 2018, FERC terminated the DOE

Notice of Proposed Rulemaking (NOPR) citing that comments received from the ISOs and RTOs did not support the assertion that generator retirements posed a threat to grid resilience (FERC 2018a). Furthermore, FERC commented that the DOE's own staff report found that resource mix changes "have not diminished the grid's reliability or otherwise posed a significant and immediate threat to the resilience of the electric grid" (FERC 2018a). U.S. DOE's effort to fast-track FERC rulemaking that would value the essential reliability and resilience attributes of fuel-secure resources was ultimately unsuccessful. However, in 2018 the Department changed tactics and considered using a mixture of statutes, including the Defense Production Act of 1950, to support coal and nuclear. A confidential memo outlining DOE's approach was leaked to the public in June 2018. After facing heavy scrutiny from the power industry and the specter of legal challenges, the Trump administration shelved this plan in October 2018 (Northey 2018).

7. OUTLOOK ON ESSENTIAL RELIABILITY SERVICES FROM WIND AND SOLAR

Essential Reliability Services must be provided to support the frequency and voltage of the BPS. Relevant technical and policy questions include:

- Which resources are technically capable of providing ERS?
- Which resources should provide ERS? and
- How much ERS should each resource provide?

Our core research objective is to answer how requirements for ERS in bulk power markets are changing over time for utility-scale wind and solar. Thus far, we have documented recent developments in ERS monitoring, technical capability, market innovation, and interconnection requirements pertaining to utility-scale wind and solar. In each area, we have seen the power sector contend with the issue of how intermittent resources can be relied upon to support the grid when their output is inherently uncertain and variable.

To expand upon our analysis of the changing role that wind and solar play in the provision of ERS, we talked with five experts from different areas of the power sector, including representatives from:

1. First Solar (utility-scale solar developer perspective),
2. CAISO (ISO/RTO perspective),
3. NREL (National Laboratory perspective),
4. A reliability engineer, and
5. A former federal regulator.

In each case, paraphrased comments represent the opinions of the individual and may not be consistent with those expressed by their respective organization.

Although there are legitimate concerns that intermittent resources may unavailable to support the grid during contingency events, there is consensus amongst the experts that VERs should contribute at their capability and questions of ERS adequacy should be considered at all timescales across the entire regional footprint, rather than at the individual plant level. This perspective ties to the concept of “good grid citizenship,” a pillar of ScottMadden’s *Solar Trifecta for A Path to Smart Utility-Scale Solar* (ScottMadden 2017). Wind and solar variability, uncertainty, and existing operational norms do not give these resources special exemption from providing ERS. As described by the representative from First Solar, the operational considerations for VERs are not so different those that were used to manage variability in conventional systems.

7.1. Evolving Expectations for Utility-Scale Solar and Wind

Table 13 shows how expectations for utility-scale solar and wind have evolved in recent years. Improvements in dispatchability, predictability, and variability have increased the flexibility of utility-scale solar and wind. Many demonstrations or examples of new and emerging characteristics and technologies have been shown for solar or wind individually. In many cases these findings can be extended to both technologies, as well as any other inverter-based resources. Brackets have been used to designate where capability has been assumed.

Table 13. Evolving Characteristics of VER Technologies

Characteristic	Old Paradigm	New/Emerging Paradigm
Dispatchability	“Must-take” or crude curtailment (Milligan et al. 2015)	Downward dispatch (i.e., targeted curtailments) or full flexibility *As demonstrated in E3, First Solar and Tampa Electric Company (TECO) study* (Nelson et al. 2018)
Uncertainty	“Unpredictable” (Milligan et al. 2015)	“Increasingly forecastable” (Milligan et al. 2015) *Intra-hour wind forecasting has increased ERCOT’s ability to respond ramps* (NERC 2018m)
Variability	“Highly variable over multiple timescales” (Milligan et al. 2015)	“Very short-term variability largely mitigated via spatial diversity” (Milligan et al. 2015) *As demonstrated by the Western Energy Imbalance Market (EIM)*
Reserve Requirements	“Requires dramatic increase in operating reserves from thermal units” (Milligan et al. 2015)	“Relatively small increase in regulation required. Can self-provide multiple reserves across multiple timescales with selective/economic curtailment” (Milligan et al. 2015)
Grid Support/ Essential Reliability Services	“Provides no grid support/decreases grid stability” (Milligan et al. 2015)	Capable of multiple grid support services (Milligan et al. 2015) *Utility-scale solar [and wind] plants are capable of “spinning reserves, load following, voltage support, ramping, frequency response, variability smoothing, frequency regulation, and power quality improvement”* (Nelson et al. 2018)

Adapted from (Milligan et al. 2015)

7.1.1. Good Grid Citizenship

Advancements in technology and operational awareness have shown that utility-scale wind and solar are capable of smoother and more flexible output, allowing these resources to provide ERS that were previously thought to be impossible (ScottMadden 2017; Milligan et al. 2015). This trend is helping to remove the operational differences between VERs and conventional resources and allowing wind and solar to contribute to overall grid reliability. "Good grid citizenship" from utility-scale wind and solar is welcome news to power sector experts, who believe that grid support is necessary across all resource mixes. Although, viewpoints differ slightly on what level of ERS should be provided by which generators.

All generators should provide certain ERS at a minimum level:

- **Former Federal Regulator:** FERC has taken the position that certain ERS (e.g., primary frequency response, reactive power factor control, voltage/frequency ride-through) must be provided by all newly interconnected BPS generators, including utility-scale wind and solar.

All generators should provide ERS at their capability:

- **Reliability Engineer:** All generation technologies should be required to provide ERS. However, renewables may not provide the same amount as a baseload resource. ERS provision should be fair and equitable; all generators should provide ERS at their capability.

All generators should provide ERS at their capability with region-specific considerations:

- **CAISO:** Requiring all generators to provide ERS may not be necessary. Instead, examine the resource mix and establish minimum ERS requirements on a regional basis.
- **NREL:** We need inclusive and flexible rules that allow for tractable regional solutions.

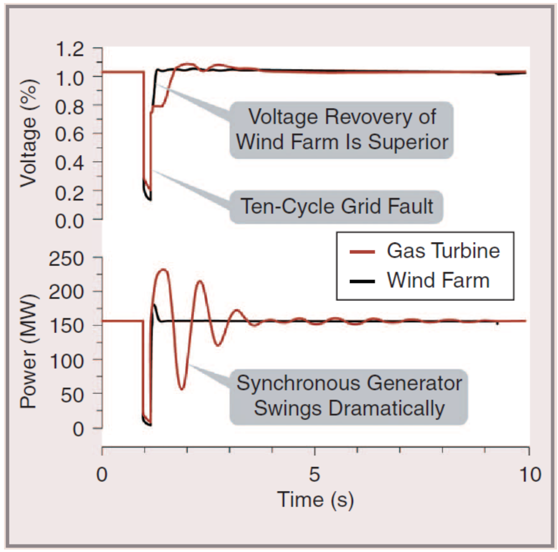
7.1.2. Potential Advantages for ERS Provision

Utility-scale solar and wind have many advantages over conventional resources in the provision of ERS. However, to realize these advantages, changes in operational norms, interconnection requirements, Reliability Standards, contractual obligations, and market structures may be necessary.

- Cost
  - Wind and solar have no fuel costs, so frequency support, ramping, and voltage support from these resources have almost zero marginal cost.
  - Wind [and solar] can ramp up or ramp down power output without the damage from mechanical wearing that is incurred by thermal generators (Milligan et al. 2015)
  - Active participation in grid balancing through downward dispatch (i.e. operating with footroom) and full flexibility (i.e., operating with headroom and footroom) helps reduce overall system operating cost by preventing the dispatch of fast-responding thermal generators (Nelson et al. 2018).
- Environmental Impact
  - Wind and solar plants have no emissions, so frequency support, ramping, and voltage support do not result in marginal greenhouse gas emissions.
  - Active participation in grid balancing through downward dispatch and full flexibility helps reduce overall system greenhouse gas emissions by preventing the dispatch of fast-responding thermal generators (Nelson et al. 2018).
- Speed and Accuracy
  - Utility-scale wind and solar plants can control their power output faster and more accurately than thermal plants (Milligan et al. 2015; NERC 2014). This control performance extends from milliseconds (AC cycles, which is the inertial time frame) to hours (load following and ramping) (Milligan et al. 2015; NERC 2014).
  - In general, wind and solar plants can return to normal operation faster than thermal plants following a disturbance because they do not rely on complex mechanical and thermal systems (NERC 2014).
- New Capabilities
  - Inverters are capable of providing reactive power support to the grid even during periods where the wind or solar resource is unavailable (e.g., at night or during calm conditions) (Loutan et al. 2017; NERC 2014).
  - Modern utility-scale wind and solar plants are capable of a broad range of power output—from zero to maximum available power. Conventional generators typically have minimum loads or may have limited flexibility due to emissions standards. Coal generators may have 40% minimum output and nuclear may have no flexibility (NERC 2014).

- ○ Unlike synchronous generators, the inertial response from wind turbines [and solar plants] is controllable. Synthetic inertia can help the interconnection ride-through a frequency disturbance while dampening oscillations (Figure 19) (Milligan et al. 2015)

Figure 19. Controllable Inertia During a Frequency Disturbance



(Milligan et al. 2015)

7.1.3. Technical Barriers to ERS Provision

In the recent past, there were technical barriers to ERS provision from utility-scale wind and solar. For example, FERC Order 2003-A exempted wind generation from the dynamic reactive power factor capabilities required by in the LGIA because older wind turbines able to supply dynamic reactive power (FERC 2004). Today, most power sector experts do not think there are significant technical barriers to utility-scale wind and solar providing many frequency and voltage support ERS functions.

There are no significant technical barriers to ERS provision:

- **CAISO:** Wind and solar are capable of many ERS including voltage control, frequency disturbance ride-through, and ramping.
- **Former Federal Regulator:** The barriers to ERS provision from VERs were once thought to be technical, but those barriers are no longer present.
- **NREL:** Renewables can certainly provide ERS

Although wind and solar have ERS capability, there are still some technical considerations that still need to be addressed:

- **First Solar:** There are technical and operational barriers, but they can be addressed.
- **Reliability Engineer:** Operators need training to understand the properties of new generators in real-time and build situational awareness. Inverter controls rely heavily on power electronics and software.

While most technical barriers to ERS capability at the plant-level have been addressed, it's important to make a distinction between those barriers and the challenges posed by sourcing ERS from resources with uncertain and variable output. Forecasting, modelling, and resource mix diversity play a large role in addressing these challenges.

7.1.4. Economic and Market Barriers to ERS Provision

Proper incentivization and market rules are key considerations to unlock the technical ERS capabilities of utility-scale solar and wind.

There are four main economic barriers to these resources providing ERS. First, because wind and solar have zero marginal cost, they are first generators in the economic dispatch merit order. Under most situations, except for extreme renewable overgeneration, these resources will not be the marginal generator (i.e., they are price takers). Economics and "must-take" operational treatment incentivize solar to operate at maximum capacity with no headroom, which makes upward frequency support infeasible. The second economic barrier is the common fixed-price terms of power purchase agreements (PPA), which pay a fixed price per kilowatt-hour for energy generated *or curtailed* (Greentech Media 2019). These terms incentivize generator owners to maximize power output over ERS. Third, Renewable Energy Certificates (RECs), which are an important revenue stream for many renewable projects, pay a fixed price per kilowatt-hour of energy generated, which further incentivizes real power output over ERS (Greentech Media 2019). Finally, the Federal tax credit for wind is production-based, further incentivizing wind generators to operate at maximum power output.

The barriers to ERS provision from utility-scale solar and wind are economic

- **CAISO:** Because other resource types may be more capable of providing ancillary services at lower prices, renewables may not be the most economic resource.

- **Former Federal Regulator:** The question now is whether there is a financial market/signal for wind and solar to provide ERS.
- **First Solar:** We advocate for flexible contracts between plant owners and off-takers so that the off-taker can optimize value from the plant. There is an opportunity cost to maintaining headroom. When it is more economic to maximize value from ERS versus pure energy contribution (e.g. under curtailment) than that flexibility is available.
- **NREL:** The barriers are rules and economics.
- **Reliability Engineer:** The barriers to ERS provision are costs to the developer.

With economic headwinds, market design can be used to design a pricing mechanism that reflect the true values of energy and ERS from VERs. RTOs and ISOs offer ERS through ancillary service markets, which generally consist of spinning reserves, non-spinning reserves, and regulation (Zhou, Levin, and Conzelmann 2016). One simple market modification that allows downward-dispatched (i.e. curtailed) VERs to participate in the regulation is to separate that market into "regulation-up" and "regulation-down" products (Greentech Media 2019). A summary of ISO/RTO markets with separated regulation products is presented in Table 14.

Table 14. Regulation Market Product Types

Regulation Product	Markets
Regulation	ISO-NE, MISO, NYISO, and PJM
Regulation-up, Regulation-down	CAISO, ERCOT, and Southwest Power Pool (SPP)

Adapted from (Zhou, Levin, and Conzelmann 2016)

7.2. Regulatory and Market Outlook

7.2.1. How Much Wind & Solar Can be Reliably Integrated?

The five power sector experts were asked what penetration of utility-scale wind and solar would pose a serious reliability threat and where might they expect it to first occur:

- **First Solar:** It is difficult to establish the penetration level at which utility-scale wind and solar will pose a serious threat to grid reliability, but it is safe to say that 100% penetration would be difficult to achieve.

Reliability threats from wind and solar can be mitigated by adequate planning

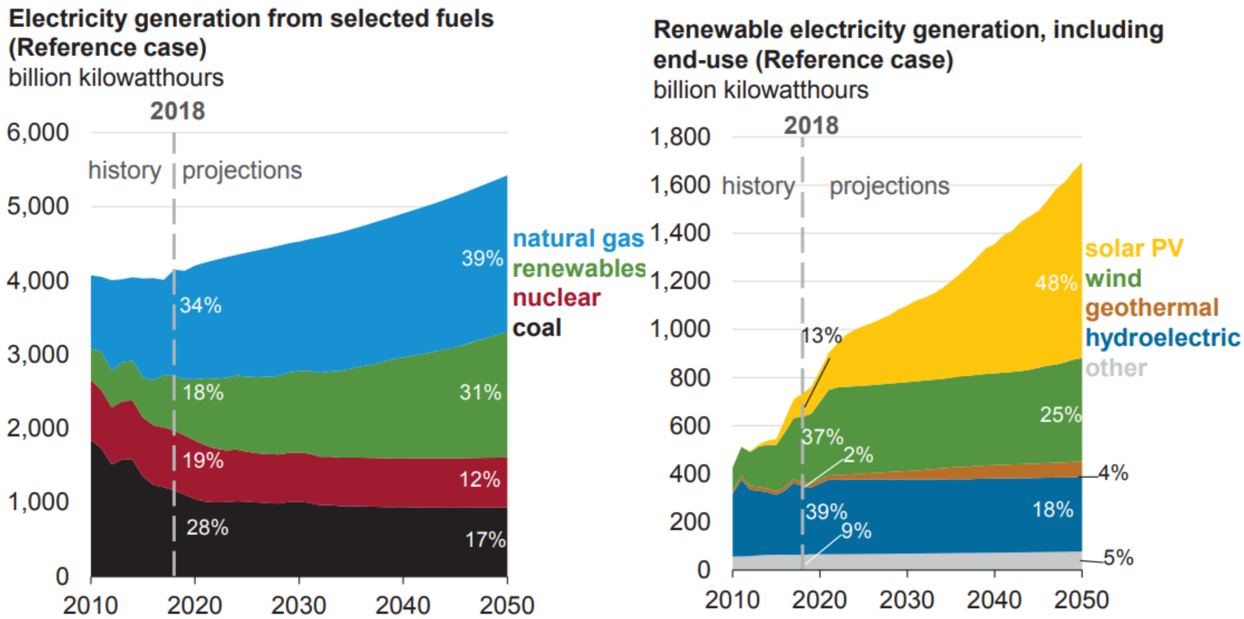
- **NREL:** There is no significant threat to grid reliability so long as we have adequate planning and coordination for utility-scale wind and solar plants.
- **Reliability Engineer:** Does not see any threats to reliability and industry is proactively addressing any foreseen challenges.

System reliability is a function of overall resource mix, not just wind and solar penetration

- **CAISO:** Geographic footprint and fuel diversity are key aspects of resource mix reliability. Growing penetrations of wind and solar in concentrated areas are not the only fuel sources creating reliability concerns. For example, a natural gas shortage could result in a contingency event that would have otherwise been a “near miss”.
- **Former Federal Regulator:** Many factors affect the reliability of the grid, and not just the degree of renewable penetration. The key question is whether you have enough flexible resources. Eight years ago, an RTO was concerned about 20% renewables—today we have several instances of 50% or greater.

While wind and solar have shown strong capability for some ERS characteristics, the reliability performance of today’s BPS relies on a diversity of generation technologies. The uncertainty, variability, and operational norms for wind and solar effectively impose an upper limit on the total amount of generation that can be provided by these resources alone. In short, there must be other resources available to generate real power and provide ERS when wind and solar are not able to. These limits are region-specific and depend on the composition of the overall resource mix, transmission capacity, and the state of technology and operational practices. In their 2019 Annual Outlook, the U.S. Energy Information Administration (EIA) forecasts renewable generation to grow nationwide from 34% in 2018 to 39% in 2050, with solar and wind providing nearly three-quarters of renewable generation (Figure 20).

Figure 20. Projections of Electricity Generation by Fuel Type



(U.S. EIA 2019)

The degree to which reliability interconnection and performance requirements for wind and solar will change in the future is related to level of grid penetration that these resources ultimately capture. NREL and GE Energy's 2010 Western Wind and Solar Integration Study found that integration of 35% wind and solar generation in the Western Interconnection would be possible with only operational adjustments, rather than major infrastructure upgrades (Lew and Piwko 2010). However, in 2018, California revised its Renewable Portfolio Standard (RPS) to require that 60% of retail electricity is obtained from renewable generators by the year 2030. This standard seems aggressive when considering that CAISO's territory is a subset of the Western Interconnection and that RPS-eligible renewable generation will likely come from solar and wind considering California's strong resource potential. CAISO has taken steps to accommodate higher levels of VERs by creating the Western Energy Imbalance Market (EIM), which has created operational and reliability benefits by increasing the geographic and temporal (relative to sunrise/sunset) diversity of its resource mix (CAISO 2018a). Similarly, ERCOT has large amounts of VER generation, with wind plants serving a record 54% of a 28 GW system load on October 27, 2017 (ERCOT 2018b). ERCOT's recent simulations have shown that wind and solar meeting 66% of a 42.2 GW load could lead to significant active and reactive power losses in the region (ERCOT 2018b). In 2018 ERCOT incorporated intra-hour forecasting to help mitigate ramping challenges in the BA (NERC 2018m). Increases to VER generation within the

ERCOT and CAISO footprints may necessitate new regional reliability requirements for interconnection and operational performance to ensure that wind and solar contribute ERS that is commensurate to their growing stake in the resource mix.

7.2.2. Outlook on Changes to the LGIA and LGIP

As documented in Section 5.1, FERC has made several modifications to the *pro forma* LGIA and LGIP since it was first issued in July 2013. The documents either specify interconnection requirements directly or reference other technical standards and "good utility practice". Modifications to LGIA articles related to reactive power capability, primary frequency response, voltage and frequency ride-through, and VER scheduling and operational visibility were found to have the most relevance to ERS. An outlook for future developments in each of these five areas is presented in Table 15.

Table 15. Outlook on LGIA Interconnection Requirements

Attribute(s)	Today	Possible Future Developments	Bellwether

Inertia	None	• Mandate on quantity
		  o Synchronous inertia
		  o Synthetic inertial response and headroom requirements
		• Compensation for synthetic inertia
			Frequency response (ERS Measure 4/M-4) trend in the Eastern Interconnection, as reported by NERC SOR report

Primary Frequency Response	• Order 842
	  o Uniform minimum capability requirements
	  o Timely and sustained response
	  o Exemptions for CHP and Nuclear
	  o Electric storage requirements to be determined by individual TPs
		• Mandate on quantity of primary frequency response and headroom requirements
		• Compensation
		• NERC Standard on primary frequency response performance for existing generators (NERC 2018j)
		• Divergence or convergence on capability requirements for battery storage
			• Frequency response (ERS Measure 4/M-4) trend in the Eastern Interconnection, as reported by NERC SOR report
			• Battery storage costs and performance

Ramping	None	• Action by FERC or individual ISO/RTOs to create markets for flexible ramping products (ISO-NE 2017) • Multi-period dispatch (ISO-NE 2017)	• BA Ramping Capability Assessments, as reported by NERC LTRA report • Increasing natural gas prices or environmental policy • Increasing solar and wind penetration • Battery storage costs and performance

Reactive Power Capability	• Order 827:
	  o Uniform capability requirements for leading and lagging dynamic power factor control
	  o Different measuring points for synchronous and non-synchronous generators
		• Modification to methodology for reactive power compensation (FERC 2014b)
		• Modification to range uniform capability requirement
		• Divergence or convergence on capability requirements for battery storage
			Actions by FERC or individual ISO/RTOs to study payment for reactive power

Voltage and Frequency Ride-through	New generators must install protective relays and other devices and follow set points in NERC Reliability Standard PRC-024-1	• Specific interconnection requirements for inverter-based resources to address:
		  o Momentary cessation
		  o Performance beyond PRC-024-1 (NERC 2018j)
			• Electric system disturbances and blackouts involving generators that unexpectedly disconnect from the system
			• Future NERC Reliability Guideline for Inverter-based Resources could influence interconnection requirements (NERC 2019c)
			• New technical performance standards for inverter-based resources on the BPS (e.g., IEEE P2800) (NERC 2019c)

Attribute(s)	Today	Possible Future Developments	Bellwether
VER Scheduling and Operational Visibility	• Order 661: SCADA requirements for large wind plants • Order 764: VER meteorological and forced outage data must be supplied to the TP	Additional data reporting requirements for wind and solar, as recommended by IRPTF's Reliability Guideline (NERC 2018j)	Future NERC Reliability Guideline for Inverter-based Resources could influence interconnection requirements (NERC 2019c)

7.2.2.1. FERC Rulemaking

Perhaps the most obvious signal on future rulemaking on ERS interconnection requirements is the title of Order 842, which is: "*Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*". The phrasing of the title hints at a forthcoming series of Orders on ERS, although the Commission's future priorities are subject to change depending on its leadership.

Recent FERC Orders 827 and 842 and a staff report on payment for reactive power show a good deal of the Commission's approach to formulating interconnection requirements for ERS (FERC 2014b). In both Orders, we see an incremental approach that favors uniform requirements for all generators. In both cases, as soon as the cost of wind and solar ERS controls were no longer considered an unjust and unreasonable burden to generator owners, these controls and uniform, minimum capability became an interconnection requirement.

Order 842 was the first instance of interconnection requirements for Primary Frequency Response capability, but the Commission stops short of specifying a required quantity of PFR, requiring headroom for upward PFR, or providing compensation. In FERC Commissioner Cheryl LaFleur's comments on Order 842, we see a "wait-and-see" approach to PFR requirements:

> "I agree with the decision not to require compensation or direct a mandatory NERC standard regarding primary frequency response at this time. However, I think the Commission should continue to monitor the impact of today's rule on frequency response performance and consider additional actions to ensure adequate frequency response if and as appropriate."
>
> -FERC Commissioner Cheryl A. LaFleur, February 15, 2018

Post Order 842, if there continue to be issues with interconnection frequency response performance, FERC may act to remedy the situation by mandating a quantity of upward and downward PFR or offering compensation for these services. However, as we see in the Commission Staff Report on Payment for Reactive Power, compensation schemes for ERS can be complex, requiring a great deal of administrative effort and stakeholder engagement, which may result in a gradual, measured response from the Commission (FERC 2014b).

7.2.2.2. The NERC ERS Subcommittees

The work of the NERC's ERS subcommittee can be used to help understand possible future developments in interconnection requirements. The ERS Subcommittees' Measures (Section 5.1) are important tools for tracking and trending inertia and primary frequency response within the interconnection. Also, Ramping Capability Assessments, which were proposed in the ERSWG's Ramping Sufficiency Guideline, are being used to proactively identify BAs with ramping challenges. These metrics have been incorporated into NERC's annual reports (Appendix B) and are likely bellwethers for future changes to interconnection requirements for frequency support.

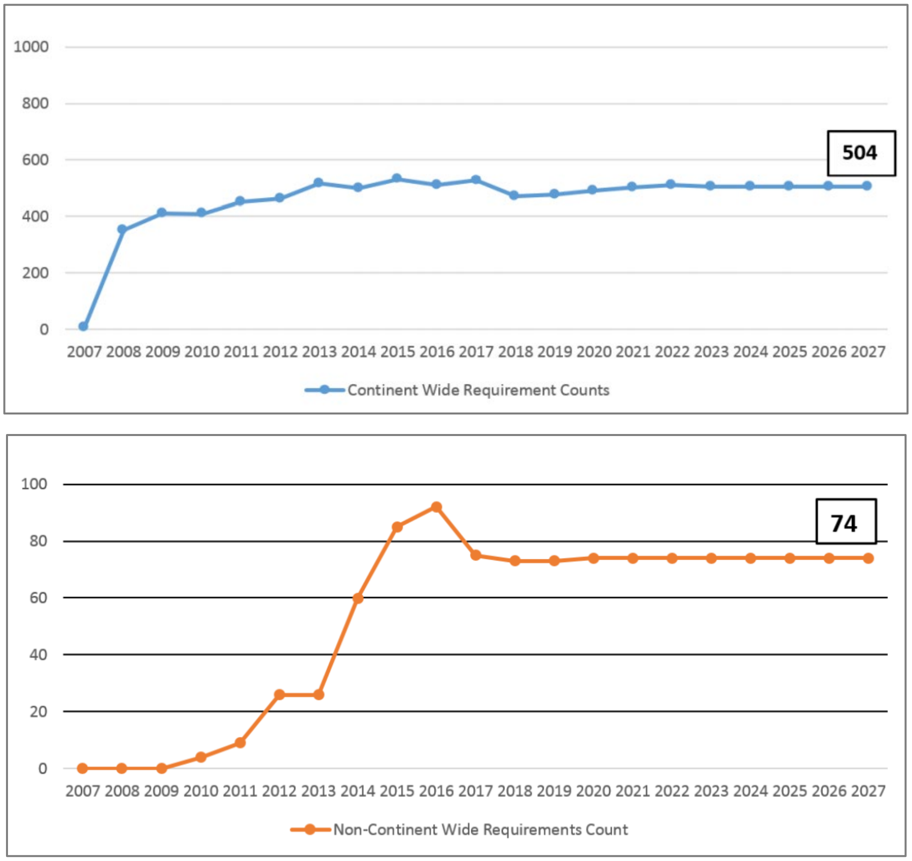
7.2.2.3. NERC Reliability Standards

While the ERS Subcommittees' recommendations did not lead to new Reliability Standards or Reliability Guidelines, they did set the groundwork for Reliability Guidelines from other subcommittees on ERS topics, such as Reactive Power Planning, Primary Frequency Response, and IBR performance.

NERC Reliability Standards and *Good Utility Practice* are often referenced in the text of the LGIA and LGIP. NERC's 2019-2021 Reliability Standards Development Plan has nine open projects—the majority of which are modifications or reviews of existing Reliability Standards rather than development of new standards (NERC 2018k). NERC has been working over the previous yeas to "transform the body of NERC Reliability Standards to a mature state" (NERC 2018k). Figure 21 shows that new continent-wide and regional Reliability Standards are expected to reach a "steady state" in future years, with the focus shifting to periodic reviews, emerging risks, and FERC directives (Hilt 2018; NERC 2018k). Therefore, it is reasonable to expect that reliability issues will be accommodated through modifications to existing Reliability Standards or new Reliability Guidelines. The notable exception to this are NERC's Critical

Infrastructure Protection (CIP) Reliability Standards, which continue to evolve with emerging cyber and supply chain risks (Hilt 2018).

Figure 21. Expected Trends for Continent-Wide and Regional NERC Reliability Standards



(NERC 2017h)

7.2.2.4. The NERC Inverter-Based Resource Performance Task Force

More recently, NERC's Inverter-based Resource Performance Task Force produced a Reliability Guideline on reliability performance of IBRs (NERC 2019c). The IBPTF's work was inspired by two recent disturbances in the Western Interconnection: The Blue Cut Fire and Canyon 2 Fire events. In both disturbances, large-scale solar plants had inadequate ride-through performance (NERC 2018j). In part, the poor performance was attributed to the inappropriate use of IEEE Standard 1547, which is designed for sub-transmission inverter-based resources (IEEE 2018). Although this Reliability Guideline on performance is not directly applicable to interconnection requirements, its recommendations give insight to current reliability challenges from large scale wind and solar plants. In some cases, these challenges are specific to IBR and are entirely new considerations for BPS reliability. For example, *momentary* *cessation* is a new capability that stops the production of active and reactive current when voltage conditions are outside of the controller's operating range (NERC 2018j). The differences between *disconnection* and *momentary cessation* may be nuanced, but takeaway is that momentary cessation inverter settings have "unintentionally propagated from distribution-connected resources to BPS-connected resources," which has posed BPS reliability challenges (NERC 2018j). A selection of IRPTF's performance recommendations that are also related to interconnection requirements is presented in Table 16. It's noted that other recommendations may ultimately affect interconnection requirements, but those listed below are closely related to reliability attributes discussed in this paper.

Table 16. Selections from NERC Reliability Guideline for BPS-Connected Inverter-Based Resource Performance, Appendix A: Recommended Performance Specifications

Attribute(s)	Reliability Guideline on BPS-Connected Inverter-Based Resource Performance Recommendation
Voltage and Frequency Ride-through	• "Momentary cessation should not be used within the voltage and frequency ride through curves specified in PRC-024-2. Use of momentary cessation is not considered *ride through* within the *No Trip* zone of these curves" (NERC 2018j) • "The PRC-024-2 voltage and frequency ride-through curves specify a 'No Trip Zone' for protection system (and control system) settings. Outside of the 'No Trip Zone' should not be interpreted as a 'Must Trip Zone'. Rather, it should be considered a 'May Trip Zone'" (NERC 2018j)
VER Scheduling and Operational Visibility	• "Inverter-based resources should be capable of receiving dispatch signals from the BA via SCADA control" (NERC 2018j) • "The following information should be available to the TOP or BA, either continuously or as needed: plant MW output, plant MVAR output, plant POI/POM terminal voltage, reactive device status, maximum available active and reactive power, MW control set point with feedback, number/percentage of inverters producing power, number/percentage of inverters available, number/percentage of inverters experiencing localized curtailment, plant ramp rate settings and capability, [and] environmental criteria that could impact energy production" (NERC 2018j)

Adapted from (NERC 2018j)

There is a high probability that the IRPTF's work will lead to new BPS interconnection requirements for wind and solar. The task force is currently developing a new NERC Reliability Guideline on interconnection requirements and also supporting the development of a new technical standard, IEEE P2800, for IBR interconnection to the BPS (NERC 2019c).

7.2.2.5. Trade Group Influence

Finally, the FERC rulemaking process allows for public comment. In the case of both FERC Order 661 and Order 845, AWEA petitioned for wind-specific interconnection requirements and to improve the interconnection process for project developers (FERC 2005c, 2018d). This shows that if the provisions of the LGIA or LGIP are viewed as unjust or too burdensome for Interconnection Customers, trade groups may step-in to lobby on their behalf.

7.2.3. Markets vs. Mandates

Provisions in the LGIA for primary frequency response, reactive power capability, and frequency and voltage ride-through are uniform, minimum capability requirements for most generators. The decision to mandate these characteristics rather than leave it up to the discretion generator owners speaks to a disconnect between the importance of these ERS and their market value. As discussed in Section 7.1.4, there are numerous economic incentives for wind and solar generator owners to choose to generate real power instead of ancillary services.

In theory, minimum ERS interconnection and performance requirements could be removed and replaced by market mechanisms that would incentivize efficient provision of grid support. In the case of reactive power capability, there would be significant challenges in designing a cost-based approach for compensating for both reactive power capability and marginal cost of provision (FERC 2014b). Furthermore, since reactive power needs are highly localized, there may be only a small number of resources capable of providing the service, which may lead to unwanted monopolistic behavior (FERC 2014b). Finally, demand for real-time power factor control is close to zero at most times and places on the grid, which means that a market for reactive power would be much smaller than one for real power (FERC 2014b). While market designs would be different for other ERS, the reactive power market case is illustrative of common challenges for creating new markets for products ancillary to real power.

The case of Xcel Energy (Section 4.1.1.3) shows that VIUs are capable of ERS innovation by mandate. Xcel uses curtailed wind to support frequency within their region (Milligan et al. 2015). Meanwhile, ISO/RTO markets have not yet created mechanisms for utilizing curtailed energy or incentivizing flexible VER operation.

It is unclear whether mandates are market mechanisms are better suited for ensuring adequate ERS. Three power sector experts weigh-in below on whether power markets are better equipped to provide ERS than VIUs are:

Mandates and VIU market structure may be advantageous for ERS Provision

- **Former Federal Regulator:** Relative to capacity and energy, the ancillary services market is quite small. In addition, markets have not been created for ERS such as primary frequency response or reactive power support. Markets are complicated and are a "significant lift" for ISO/RTOs to create (high cost of policy development and implementation). Regulators must look at the cost/benefit of new markets—RTOs must create new software and stakeholder processes and transaction costs may outweigh the benefits. If ERS doesn't cost a lot to provide, why not require it?
- **NREL:** In theory, an auction process should be more efficient because of transparency and standardization. The stakeholder process for RTO rule changes takes much longer than action by VIUs. The early adoption of wind regulation in Xcel's service territory shows that centralized utilities can sometimes minimize cost faster than markets.

There are tradeoffs between mandates and markets for ERS Provision

- **CAISO:** Efficient markets can assure that ERS is provided in a cost-effective manner. However, stakeholder processes can be challenging. VIUs have complete information for resources within their service territories, which creates planning advantages.

8. CONCLUSION

The integration of variable resources on the Bulk Power System is an ongoing trend in the U.S. and globally. Due to the different technical characteristics of renewable generation and the variability and forecast uncertainties of solar and wind energy, the reliable integration of VERs requires changes to technologies, operational practices, power market mechanisms, and regulatory requirements. A key aspect of ensuring future BPS reliability is determining whether utility-scale solar and wind can or should provide Essentially Reliability Services. In some cases, there have been reliability concerns as conventional generators that inherently provide certain ERS become a smaller part of the BPS resource mix (NERC 2014).

Through stakeholder interviews and literature review covering both academic research and industrial reports, we concluded that the technical capability of utility-scale wind and solar providing ERS is not fully enabled by current market rules and regulation for the U.S. BPS. Advancements in technology and operational awareness have shown that utility-scale wind and solar are capable of smoother and more flexible output, allowing these resources to provide ERS that were previously thought to be impossible (ScottMadden 2017; Milligan et al. 2015). While the magnitude of economic and environmental benefits from wind and solar providing ERS has not yet been fully studied by the research community, NERC reliability studies have led to Federal interconnection requirements for minimum dynamic reactive power factor control, ride-through performance, and primary frequency response capability for all generators including wind and solar. By documenting the relevant U.S. Federal rulemaking on ERS and interconnection requirements over the last decade, we see a trend of convergence in bottom-line reliability requirements for synchronous and non-synchronous generators. The recent Federal rulemaking on primary frequency response (FERC Order 842) signaled a possible series of subsequent Orders on ERS provision.

Although Federal rulemaking is on track to set minimum requirements for ERS capability as renewable integration increases, a lack of financial incentives is a barrier to ERS provision from utility-scale wind and solar. A remaining question is how to design cost-based pricing or other competitive mechanisms that would allow grid operators to co-optimize energy and ERS value from solar and wind resources. Through case studies on U.S. regional practices and international markets, we understand that this is a nascent area. Multiple market reforms have emerged in European regions over the past two years. In general, these reforms set an equitable playing field for all resources to bid into markets for grid reliability services.

Besides solar and wind, inverter-based technologies include battery storage, which is expected to play a large role in both the energy and ancillary service markets. The recent work of NERC's Inverter-based Resource Performance Task Force has signaled that there will be more changes to technical guidelines and interconnection requirements for inverter-based resources on the BPS in the future.

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APPENDIX A. GLOSSARY OF TERMS

Term	Definition
Active Power Control (APC)	"APC is the ability of a system to control real power in order to maintain load and generation balance." (NERC 2014)
Area Control Error (ACE)	"The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection." (NERC 2018g)
Automatic Generation Control (AGC)	"Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction." (NERC 2018g)
Contingency Reserves	"The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts Level 2 or Level 3). The capacity may be provided by resources such as Demand Side Management (DSM), Interruptible Load and unloaded generation." (NERC 2013a)
Control Area	"Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by NERC" (FERC 2016c)
Deadband	Deadband parameter "represents a minimum frequency deviation (e.g., ±0.036 Hz) from nominal system frequency (i.e., 60 Hz in North America) that must be exceeded in order for the generating facility to provide primary frequency response." (FERC 2018c, 842)
Distributed Energy Resource (DER)	"A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES)." (NERC 2017a)
Droop	"Droop refers to the variation in real power (MW) output due to variations in system frequency and is typically expressed as a percentage (e.g., 5 percent droop). Droop reflects the amount of frequency change from nominal (e.g., 5 percent of 60 Hz is 3 Hz) that is necessary to cause the main prime mover control mechanism of a generating facility to move from fully closed to fully open." (FERC 2018c, 842)

Term	Definition
Footroom (floor-room)	“Floor-room refers to the difference between the current operating point of a generating facility and its minimum operating capability and represents the potential amount of additional energy that can be withdrawn by the generating facility in real-time. Stated differently, a generating facility with floor-room will have the capability to reduce its MW output in response to a frequency deviation.” (FERC 2018c, 842)
Frequency Nadir	“The point at which the frequency decline is arrested (following the sudden loss of generation) is called the frequency nadir, and represents the point at which the net primary frequency response (real power) output from all generating units and the decrease in power consumed by the load within an Interconnection matches the net initial loss of generation (in megawatts (MW)).” (FERC 2018c, 842)
Frequency Response Obligation (FRO)	“The Balancing Authority’s share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.”(NERC 2018g)
Good Utility Practice	“Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.” (FERC 2016c)
Governor	“The electronic, digital or mechanical device that implements Primary Frequency Response of generating units/generating facilities or other system elements.” (NERC 2018g)
Headroom	“headroom refers to the difference between the current operating point of a generating facility and its maximum operating capability, and represents the potential amount of additional energy that can be provided by the generating facility in real-time.” (FERC 2018c, 842)
Interconnection	“A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.” (NERC 2018g)
Interconnection Frequency Response Obligation (IFRO)	“The IFRO is the minimum amount of frequency response that must be maintained by an Interconnection. Each BA in the Interconnection should be allocated a portion of the IFRO that represents its minimum annual median performance responsibility. To be sustainable, BAs that may be susceptible to

Term	Definition
	islanding may need to carry additional frequency-responsive reserves to coordinate with their UFLS plans for islanded operation." (NERC 2018a)
Inverter	"A machine, device, or system that changes direct-current power to alternating-current power." (IEEE n.d.)
Large Generating Facility	"A Generating Facility having a Generating Facility Capacity of more than 20 MW" (FERC 2003)
Momentary Cessation	Momentary cessation is a new capability that stops the production of active and reactive current when voltage conditions are outside of the controller's operating range (NERC 2018j).
Non-dispatchable Resources	"These power sources cannot be relied upon to meet demand in a short amount of time, so they are non-dispatchable."(Harack 2010)
Non-Spinning Reserve	"1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time." (NERC 2018g)
Operating Reserves (ORs)	"Operating Reserves (ORs) are characterized by the BPS's ability to maintain specified reserves (in some BAs), adequate reserves, or both, beyond the firm system demand. ORs consist of attributes such as regulation, load following, and contingency reserves (spinning, non - spinning and supplemental). Load following in a particular area is provided over a period of hours and a wider range of output as opposed to resources that provide regulation within a time frame of minutes and over a smaller output range. Resources that are slated to provide contingency reserve services are utilized during a contingency event, and contingency reserves ensure resources are available to replenish the amount of output used during the event, thus returning the system to the level of balance before the event." (NERC 2014)
Power Factor	"Ratio of real power to apparent power." (FERC 2016a)
Primary Frequency Response	"The immediate proportional increase or decrease in real power output provided by generating units/generating facilities and the natural real power dampening response provided by Load in response to system Frequency Deviations. This response is in the direction that stabilizes frequency." (NERC 2018g)
Qualifying Facility (QF)	The Public Utility Regulatory Policies Act of 1978 (PURPA) established "a new class of generating facilities which would receive special rate and regulatory treatment. Generating facilities in this group are known as qualifying facilities (QFs), and fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities." (FERC 2017b)
Ramp Rate	"(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period.

Term	Definition
	(Generator) The rate, expressed in megawatts per minute, that a generator changes its output." (NERC 2018g)
Reactive Power	"The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar)." (NERC 2018g)
Resource Contingency Criteria (RCC)	The RCC usually refers to the interconnection disturbance event caused by the loss of the two largest resources (N-2) (NERC 2019b).
Ride Through	"Ride through means a Generating Facility staying connected to and synchronized with the Transmission System during system disturbances within a range of over- and under-frequency conditions, in accordance with Good Utility Practice." (FERC 2003)
Secondary Frequency Control	"Secondary Frequency Control – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system." (NERC 2012b)
Small Generating Facility	"A device used for the production of electricity having a capacity of no more than 20 MW" (FERC 2005b)
Static VAR Compensator (SVC)	"This is a Flexible AC Transmission System (FACTS) device that consists of thyristor-controlled reactors (TCRs), thyristor-switched capacitors (TSCs), and fixed capacitors acting as a harmonic filter."(NERC 2016c)
Supervisory Control and Data Acquisition (SCADA)	"A system of remote control and telemetry used to monitor and control the transmission system." (NERC 2018g)
Synchronous Condenser	"Synchronous condensers are synchronous machines that are specially built to supply only reactive power." (FERC 2005a)
Synchronous Inertial Response (SIR)	"Synchronous Inertial Response (SIR) is an instantaneous response that is continuously self-deployed from synchronous machines following disturbances and is a key determinant of the strength and stability of the power system. Synchronous Inertial Response is defined as stored kinetic energy (at nominal frequency) that is extracted from the rotating mass of a synchronous machine following an imbalance in a power system. Stored kinetic energy is based on the commissioned design capability of the plant." (ERCOT 2013)

Term	Definition
Transmission System	“Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.” (FERC 2016c)
Under Frequency Load Shedding (UFLS)	“UFLS is designed to be activated in extreme conditions to stabilize the balance between generation and load. Under frequency protection schemes are drastic measures employed if system frequency falls below a specified value.” (FERC 2018c, 842)
Vertical Integrated Utilities	“They own the generation, transmission and distribution systems used to serve electricity consumers.” (FERC 2017a)

APPENDIX B. ERS MEASURES AND SUFFICIENCY GUIDELINES

B.1. ERSTF Measures

The ERSTF recommended ten Measures and Industry Practices to track and trend ERS at the Interconnection and BA levels in their November 2015 Measures Framework Report (NERC 2015). Measures are to be calculated by entities identified by the ERSTF and submitted to NERC subcommittees for further analysis. Industry practices are optional and only recommended to certain entities. The focus of the metrics is on the management of frequency, net demand ramping, and voltage in both short-term operational and long-term planning horizons. Although ramping is considered a subset of the frequency support ERS Building Block, the ramping Measure was differentiated from the other frequency metrics because of timing and operational differences (NERC 2015). Table 12 summarizes the Measures and Industry Practices recommended by the ERSTF to assess and forecast the quantity of ERS services across different geographic and time-scales.

Measures 1-4 and Industry Practice 5 are related to frequency response after a disturbance.

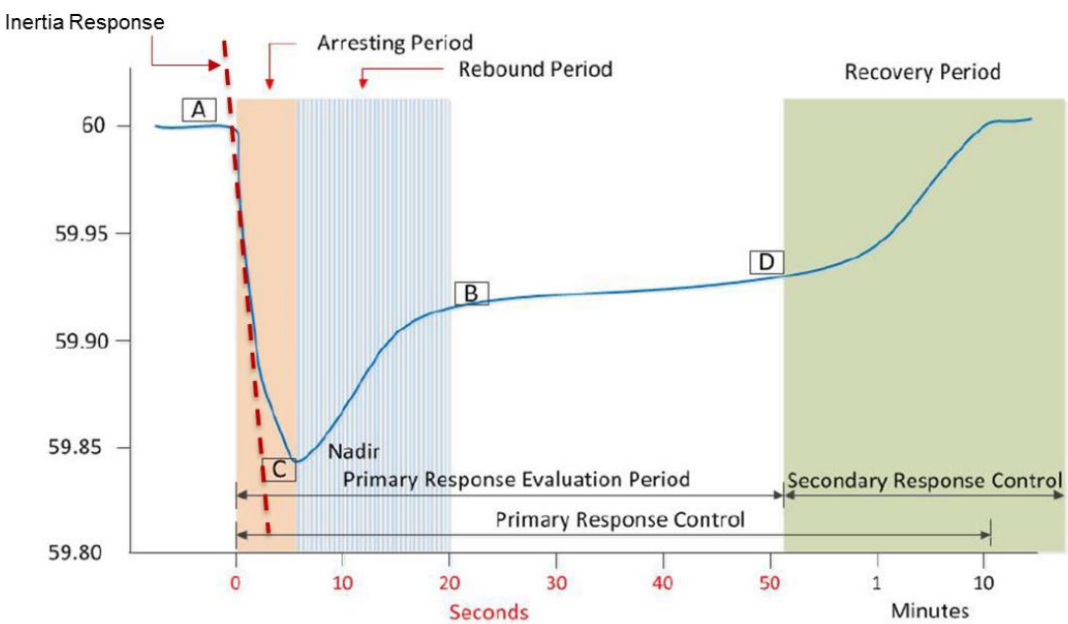
- **Measures 1 & 3** quantify the amount of Synchronous Inertial Response (SIR) within an interconnection (Measure 1) or individual BA (Measure 3). The SIR is an instantaneous injection of kinetic energy into the system following a disturbance, which can have the effect of arresting a frequency decline. SIR is proportional amount of synchronized generators a within the interconnection or balancing area (NERC 2015). Interconnections and BAs were asked to identify their minimum hourly instance of SIR over the course of a year and forecast minimum inertial response for the next three years.

- **Measure 2** is extrapolated from Measure 1 and corresponds to the frequency deviation (in Hz) over 0.5 seconds following a hypothetical Resource Contingency Criteria (RCC) event during minimum interconnection SIR conditions. This measure is also known as the rate of change of frequency (RoCoF).

- **Measure 4** is a full suite of time and frequency measurements that are used to track interconnection frequency response performance during a disturbance. Note that

Measure 4 expands upon M-4/ALR1-12, NERC's traditional metric for frequency response (NERC 2015). Frequency excursions are described by three key values: the pre-disturbance frequency (Point A), the nadir (Point C), and the stabilization period frequency (Point B) (Figure 22). Refer to Section 2.2.1 for a full description of time periods and frequency values commonly used to describe frequency excursions.

Figure 22. Typical Frequency Excursion and Recovery



(NERC 2016b)

- **Sub-Measure 4.1: Point A to Point B frequency response** quantifies the stabilizing effectiveness of inertia, FFR, and PFR between initial event and the average stabilizing frequency. It is a ratio of the total generation lost over the change in frequency between Points A and B.

$$IFRM_{A-B} = \frac{Generation\ Lost\ (MW)}{Frequency_A - Frequency_B}$$

- **Sub-Measure 4.2: Point A to Point C frequency response** quantifies the arresting effectiveness of the inertial response and FFR between the starting frequency and the frequency nadir. It is the ratio of total generation lost over the change in frequency between Points A and C.

$$IFRM_{A-C} = \frac{Generation\ Lost\ (MW)}{Frequency_A - Frequency_C}$$

- **Sub-Measure 4.3: Point C to Point B ratio** describes the governor's capability to arrest and stabilize system frequency relative to the total size of the frequency deviation. It is the ratio of the difference between the stabilizing frequency (Point B) and the nadir frequency (Point C) normalized by the difference between the initial frequency (Point A) and the nadir (Point C).

$$C\!:\!B\ Ratio = \frac{Frequency_C - Frequency_A}{Frequecy_B - Frequency_A}$$

- **Sub-Measure 4.4: C' to C ratio** captures the effect of governor frequency withdrawal. In some instances of poor frequency response performance, governor support may be prematurely withdrawn from the system resulting a second low point (Point C') following the stabilizing frequency (Point B). The C' to C ratio compares the governor withdrawal minimum (Point C') to the nadir (Point C) relative to the pre-disturbance frequency (Point A). Point C' is sometimes denoted as C_n to allow for prolonged frequency withdrawals.

$$C'\!:\!C\ Ratio = \frac{Frequency_{C'} - Frequency_A}{Frequecy_C - Frequency_A}$$

- **Sub-Measure 4.5: Time-based measures** capture the difference in time between the nadir (point C) and the pre-disturbance frequency (point A) and any subsequent governor withdrawal minimum (point C'). These measures can be used to show compliance with Reliability Standard BAL-003-1.1 (Appendix C).

  - **Sub-Measure 4.5a**

$$Time\ between\ nadir\ and\ initial\ event = t_C - t_0$$

  - **Sub-Measure 4.5b**

$$Time\ between\ governor\ withdrawl\ and\ initial\ nadir = t_{C'} - t_C$$

  Point C' is sometimes denoted as C_n to allow for multiple frequency withdrawals.

- **Sub-Measure 4.5c**

$$Time\ between\ governor\ withdrawl\ and\ initial\ event = t_{C'} - t_0$$

Point C' is sometimes denoted as C_n to allow for multiple frequency withdrawals.

- **Industry Practice 5** recommends that BAs develop a real-time inertial model. While not considered a required Measure, Industry Practice 5 increases operator situational awareness in BAs that are experiencing declining system inertia (NERC 2015).

In 2015, the ERSTF led an effort to implement Measures 1-4 and Industry Practice 5. Measures 1-4 were assigned to NERC's Resources Subcommittee and Frequency Working Group. Data were requested from WECC, EI, and select BAs to calculate Measures 1-3 for years 2011-2014 along with projections for 2015-2017 (NERC 2015). There were significant challenges mapping generator inertia constants to generator status at the interconnection level (Measures 1 and 2) (NERC 2015). Initial results showed minimal urgency for calculating Measures 1 and 2 in the EI due to low amounts of non-synchronous generation in that interconnection at the time (NERC 2015). Measure 3 was collected for nine BAs and downward inertia trends were identified in ERCOT and ISONE (NERC 2015). Measure 4, the suite of frequency response metrics, had not shown substantial degradation in any of four interconnections at that time (NERC 2015). Based upon these initial data gathering efforts, the ERSTF recommended annual collection of Measures 1-4 and three-year projection of Measures 1-3 for to monitor areas experiencing low SIR and to encourage proactive identification of inertia deficits across the BPS (NERC 2015). At the time of reporting, CAISO and ERCOT had adopted Industry Practice 5 by implementing real-time models capable of alerting system operators to low inertia conditions (NERC 2015).

Measure 6 tracks net demand variability, which determines the system ramping capability necessary to balance changes in generation or load from non-dispatchable and/or variable resources. It should be calculated using the finest time interval possible (e.g., 1-minute or 5-minute data) (NERC 2015). Net demand is calculated by subtracting certain variable generation and/or load (usually utility-scale wind and solar generation) from load. The slope (MW/min) of resulting profile shows the "ramps" that dispatchable resources must achieve to balance the generation with load. Measure 6 is the "maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down ramps… [for] the current study year, three recent historical years, and projected four years in the future" (NERC 2015). Proof-of-concept for Measure 6 was shown in a conference paper authored by members of the ERSTF that compared hourly load and net-load data for CAISO and ERCOT, which showed difference in the magnitude of ramps and their sensitivity to VER penetration between the two BAs (Abdel-Karim et al. 2015). The ERSTF recommended that the Reliability Assessment Subcommittee monitor Measure 6 at the BA level (NERC 2015). In 2015, the ERSTF found that CAISO was the only BA (of the ten surveyed) that anticipated a significant increases in net demand variability in the near-term future due to significant VER penetration, non-dispatchable generation, and base-loaded generation (NERC 2015). These maximum ramps were expected to occur in the spring during afternoon hours as output from solar resources decline (NERC 2015).

Measures 7 and 8 and **Industry Practices 9 and 10** relate to maintaining intended system voltage levels by controlling reactive power production and absorption. Reactive power cannot be transmitted long distances, so voltage issues tend to be more local than frequency issues, which may span an entire interconnection or balancing area (NERC 2015). For this reason, NERC has recommended that planners consider sub-areas that have similar electrical characteristics or share certain resources and reactive power equipment (NERC 2015). For example, an “urban area that has limited reactive resource relative to its load and must import large amounts of real power” may be considered as a separate sub-area from a “large rural area with weak transmission, limited load, and significant economic real power resources” even if they are within the same planning region (NERC 2015).

Measure 7 was assigned to the Performance Analysis Subcommittee and the System Analysis and Modeling Subcommittee and “tracks the static and dynamic reserve capability per total megawatt load… and load power factor for distribution at the low side of transmission buses” (NERC 2015). The ERSTF requested historical, current, and forecasted data on Measure 7 from BAs (NERC 2015). Most entities were found to have “significant” amounts of reactive reserve capability while maintaining load power factors over 90% (NERC 2015). The ERSTF deemed Measure 7 helpful for evaluating the reactive strength of the system, but emphasized that entities should define sub-areas to enhance the usefulness of Measure 7 (NERC 2015).

Measure 8 would have tracked BA voltage limit exceedances, but was found to have too much overlap with Industry Practice 9, which is a full suite of retroactive analysis for events related to reactive capability and voltage performance (NERC 2015). Industry Practice 9 also has overlap pre-existing NERC Standards and event reporting requirements, but additional Industry Practice 9 analysis may be conducted by the Event Analysis Subcommittee (NERC 2015).

Industry Practice 10 recommends two study processes that supplement short circuit capability assessments required by NERC Standard TPL-001-4. The utility of these additional study processes has been demonstrated in ERCOT, and the ERSTF recommends them to Planning Coordinators in other regions where there is significant penetration of nonsynchronous resources (NERC 2015).

B.2. ERSWG Sufficiency Guidelines

The ERSTF used the Measures to develop interim Sufficiency Guidelines (SGs), which were presented in their December 2016 whitepaper (NERC 2016b). The SGs encourage traditional methods of frequency support, ramping and balancing for regions with high penetrations of non-dispatchable resources, and voltage support that encourages local action (NERC 2016b). The SGs are intended to be processes that lead to positive ERS outcomes, rather than numerical standards, to allow for the heterogeneous characteristics of sub-areas, balancing areas, and interconnections (NERC 2016b). In addition to SGs, the ERSWG white paper re-evaluated the ERS Measures, suggesting revision and reconsideration where appropriate (NERC 2016b).

The inertia sufficiency guideline explores a system's capability to avoid UFLS following an RCC event by quantifying a minimum inertia value for the interconnection and/or balancing area. The SG recommends a four-part assessment of inertia. First, a top-down approach is used to determine the theoretical minimum amount of SIR necessary to provide enough arresting capability for the system to avoid the first level of UFLS following the disturbance. For this exercise, it's assumed that all inertia comes from traditional, synchronous sources. Next, the bottom-up approach is used to consider the likely dispatch of resources during the event by considering factors such as must-run units, baseload unit maintenance schedules, behind-the-meter resources, and regulatory requirements (NERC 2016b). Once a minimum inertia value is established it is assessed against forecasted inertial conditions for future resource mixes. Finally, where there are cases of extremely low system inertia, mitigating alternatives can be considered such as out-of-merit commitment of synchronous generators, use of synchronous condensers, and increasing the rate of PFR by adding fast frequency response resources (e.g., load resources, storage, and synthetic inertia) (NERC 2016b).

The ramping sufficiency guideline was developed in collaboration with the ERSTF, the NERC Resources Subcommittee (RS), and the NERC RAS to give BAs methods for identifying ramping challenges so that they can "meet the shared responsibility of supporting interconnection frequency” (NERC 2016b) A key objective is the early identification of these challenges so that BAs can make changes to resource planning and unit commitment processes to preemptively address future challenges (NERC 2016b). As a best practice, BAs are asked to perform a self-analysis consisting of two pre-screening steps followed by a Control Performance Standard 1 (CPS1) evaluation (NERC 2016b). The recommended pre-screening evaluation method is used to identify hours with “constrained operating conditions” such that the system load is low, non-dispatchable resources are meeting a large portion of the demand, and system ramp capability is limited (NERC 2016b). If non-dispatchable resources are meeting a considerable amount of the load, usually between 30% and 50%, the BA can complete a second-level prescreen to determine whether the ramping capacity of dispatchable resources can cover the regulation, load following, and net load change requirements for the next one to three hours (NERC 2016b). Next a CPS1 evaluation is recommended. CPS1 is already tracked by BAs to show compliance with NERC Standard BAL-001-2. In some cases, CPS1 excursions below 100% can be attributed to BA ramping deficiencies (NERC 2016b). The ERSWG recommends reviewing three years of historical hourly CPS1 data and quantifying the amount, trend, and seasonality of 1) hourly CPS1 excursions below 100% and 2) three consecutive hourly CPS1 excursions below 100%. Failures of the CPS1 evaluations will prompt NERC RS to ask the BA for further review of CPS1 performance. Examples of CAISO and ERCOT ramping SG analysis methodology are featured within the SG report.

The voltage support sufficiency guideline prioritizes the definition of sub-areas summarizes strategies and recommended practices from the December 2016 NERC Reactive Power Planning and Operations Guideline (NERC 2016c). First the Planning Coordinator and Transmission Planner should create criterion for defining “reactive power sufficiency” sub-areas within their larger study area (NERC 2016b). As described previously, sub-area groupings should group together areas with unique characteristics (e.g., urban versus rural) and should be agnostic of corporate and political boundaries (NERC 2016b). In the event of a disturbance, to avoid cascading behavior, each sub-area should have sufficient reactive and voltage performance such that it does not depend on other sub-areas for support (NERC 2016b). Finally, planners and operators should develop sufficiency measures for each sub-area depending upon specific reactive characteristics (NERC 2016b). These sufficiency measures may include pre-contingency min/max voltage, post-contingency min/max voltage, or minimum on-line reactive reserves (NERC 2016b). The Reactive Power Planning and Operations Guide also provides strategies and practices for reactive and voltage control that are rooted in NERC Standards and the most recent requirements set by FERC Order 827 (NERC 2016b).

B.3. Updates and Briefs

The original ERSWG work scope included a report on final Sufficiency Guidelines in December 2017, but the subcommittee's approach was modified following release of the interim SG report, noting that a lengthy vetting process of measures could delay a final report (NERC 2017b). Instead, between May 2017 and March 2018, the ERSWG released a series of technical briefs and briefs for regulators and policymakers on groupings of measures and their applications. Notably, "Sufficiency Guideline" language was absent from the briefs and the analyses were clearly divided into "historical" and "forward looking". This new bifurcation aligns efforts to trend the Measures with NERCs annual SOR and Long-Term Reliability Report (LTRA) (Sections B.4 and B.5). The following is a summary of briefs released by the ERSWG:

- Policy Briefing on Reactive Power (May 2017): This brief summarizes the findings of the NERC System Analysis and Modeling Subcommittee (SAMS) and Performance Analysis Subcommittee (PAS) in their February 2017 Measure 7 Analysis report, which found that Measure 7, or Reactive Capability on the System, would "not provide useful, consistent, and informative reactive capability trends related to a changing resource mix" (NERC 2017c). Also, FERC Order 827 (issued on June 16, 2016), was found to address some of the underlying reactive deficiency concerns which prompted the ERSTF to propose Measure 7 in the first place (NERC 2017c). Consistent with SGs, SAMS recommended "sub-area treatment" of reactive power and voltage control issues informed by NERC's Reactive Power Planning and Operations Guide, interconnection studies, planning assessments, and operational studies (NERC 2017c).

- Historical Frequency Trends Technical Brief & Historical Frequency Trend: A Brief for Regulators and Policymakers (January 2018): These briefs summarize the high-level rationale and technical processes for collecting and analyzing historical frequency data from interconnections on Measures 1, 2, and 4. Measure 1, or SIR data, is to be provided by interconnections to NERC RS on a quarterly basis (NERC 2018b). It is noted that there is an effort to develop software to automate the submission of these data to NERC (NERC 2018b). Measure 2, or the RoCoF, is to be analyzed annually by NERC RS for frequency disturbances during low SIR (NERC 2018b). Measure 4, or the holistic set frequency response measures, is provided by interconnections on a quarterly basis for “Metric 4” disturbances (NERC 2018b). NERC reports on “Metric 4” events in the annual SOR and considers them to be significant frequency disturbances--the similar naming is coincidental (NERC 2018b). Historical frequency trends, by way of Measures 1, 2, and 4, are to be presented in the annual SOR (NERC 2018b).

- Forward-Looking Frequency Trends Technical Brief (March 2018): This brief examines the varied methodologies used by interconnections to forecast frequency response performance. Additionally, the brief discusses unique market and policy strategies for preserving frequency performance in ERCOT and Hydro Québec (HQ). ERCOT and HQ tend to have proportionally less synchronous inertia than the EI and WI because their of their unique resource mixes (NERC 2018d). These interconnections have historically faced low-inertia conditions and, as such, have innovative short-term inertia forecasting capabilities. In March 2017, ERCOT implemented a real-time tool to forecast day-ahead and real-time inertia and compares this to the Response Reserve Service (RRS) that have been procured (NERC 2018d). HQ has tracked PPPC, a metric strongly correlated with synchronous inertia, since 2006 (NERC 2018d). Based upon extensive modeling, real-time measurement, and operational awareness, HQ and ERCOT have improved operational and planning for frequency response performance (NERC 2018d). The EI and WI have less historical experience with low inertia and their larger, more diverse footprint makes fine-grained scenario analysis, such as that used by ERCOT and HQ, impractical (NERC 2018d). As an initial step, the ERSWG worked with the Eastern Interconnection Planning Collaborative (EIPC) and the Western Electricity Coordinating Council (WECC) to use Measures 1,2, and 4 to understand future trends across several key planning cases (e.g., Spring Light Load, Heavy Spring, etc.) every two to three years (NERC 2018d).

- Disposition of ERSWG Measure 3 (March 2018): In this brief, the ERSWG discontinues the collection of Measure 3, SIR at the BA Level. The original intent of this data collection was to “build-up” to interconnection-level SIR data from BA SIR data (NERC 2018c). Improvements in Measure 1 data-collection processes have rendered Measure 3 unnecessary (NERC 2018c).

- Historical Balancing Trends: A Brief for Regulators and Policymakers (March 2018): This brief describes a CPS1 analysis of 1-hour and 3-hour ramps for BAs that is identical to the interim SG for ramping. Measure 6 data are to be provided by BA to NERC RS on a quarterly basis and reported in the annual SOR (NERC 2018f).

- Forward-Looking Net Demand Ramping Variability Technical Brief (March 2018): In this brief, ERSWG recommends two forward-looking screening methodologies to assess BA ramping capability as its resource mix evolves. The *Non-dispatchable Resource Penetration Screen* compares expected hourly load to the capacity of non-dispatchable resources expected to be operational at the time and is identical to the interim SG Level 1 Ramp Penetration Screen. The new *Flexible Resource Screen* tests whether there is a surplus of flexible resources available for dispatch that can cover the total output of the non-dispatchable resources expected to be operational for a given hour. On an annual basis, the NERC RAS ask certain BAs to conduct the *Non-dispatchable Resource Penetration Screen* and *Flexible Resource Screen* based a high-level review of changing load profiles and resource mix (NERC 2018e). If the screening results lead to ramping concerns, the BA may be asked to conduct additional analysis, such as the *Ramping Capability Screen* described in the interim SG (NERC 2018e). Screening results will be presented in the annual LTRA.

B.4. Integration with NERC State of Reliability Report

ERS frequency Measures were featured in NERC's 2018 State of Reliability (2018 SOR) report for the 2017 Operating Year. Chapter 2 and Appendix E of the 2018 SOR are dedicated to frequency response performance at the interconnection-level. The separation of frequency response from other reliability assessment in the 2018 SOR is a departure from previous years and was motivated by the nuance and outsized importance of this characteristic in the face of a changing resource mix (NERC 2017f, 2018h). Key Finding #5 of the 2018 SOR states that frequency response had mixed performance over the previous five years in the four interconnections (NERC 2018h). Data from ERS Measures 1, 2, and 4 are presented in Appendix E of the 2018 SOR. Notably, there is no mention of ERS Measure 6 or net load variability in SOR 2018, despite recommendations for inclusion in a recent a brief issued by the ERSWG (NERC 2018f). The omission could indicate that there wasn't enough time for meaningful ramp analysis or that NERC is pursuing other methods for historical ramp analysis.

Much of the frequency analysis covers Metric 4 (M-4), NERC's Interconnection Frequency Response Reliability Indicator. M-4 has been tracked in the annual SOR reports for several years and is equivalent to the Interconnection Frequency Response Metric ($IFRM_{A-B}$), which evaluated against the Interconnection Frequency Response Obligation (IFRO) set forth in BAL-003-1.1 for compliance. As discussed in Appendix B, M-4 and ERS Sub-Measure 4.1 are identical. Each year, NERC selects significant frequency events in each interconnection for M-4/BAL-003-1.1 analysis based upon the amount of MW loss and change in frequency between the pre-disturbance frequency (Point A) and the stabilizing frequency (Point B). Stabilizing frequency response ($IFRM_{A-B}$), was found to be increasing in the WI and TI, but neither increasing nor declining in the EI or QI (NERC 2018h).

ERS Sub-Measure 4.2 ($IFRM_{A-C}$) describes arresting frequency response, which occurs over a shorter time interval than stabilizing frequency response (i.e., ERS Sub-Measure 4.1, M-4, and $IFRM_{A-B}$). Historically, there has been less emphasis in SOR reports on measuring the arresting frequency response between the pre-disturbance frequency (Point A) and the nadir (Point C) even though arresting performance in this interval determines whether system frequency will decline below UFLS (NERC 2017f). Measurement of $IFRM_{A-B}$, or stabilizing frequency response, has been the standard frequency response performance metric for NERC reporting because the time interval of the metric is better matched to legacy system scan rates and AGC signals (NERC 2018h). The ERSWG work highlighted the importance of measuring arresting frequency response, or $IFRM_{A-C}$, to isolate and quantify the frequency arresting effects of faster responding frequency support such as synchronous inertia, load damping, and FFR. SOR 2018 provides the first instance of statistical testing of arresting frequency response, and though not explicitly stated, the ERSWG findings and Sub-Measure 4.2 likely inspired these new efforts. Statistical analysis showed that arresting frequency response was increasing in absolute value (i.e., improving) in the EI, TI, and QI but that neither increasing nor declining in the WI over the 2013-2017 operating years (NERC 2018h).

In Appendix E of the 2018 SOR, stabilizing and arresting frequency response are further analyzed using summary statistics and multiple linear regression over season, load profile, and other system state indicators. Other data for ERS Measures 1, 2, and parts of 4 are presented for the 2017 operating year with no analysis or historical trending. For ERS Measure 1, a time series plot of minimum SIR is presented for each of the four interconnections along with Maximum SIR. For ERS Measure 2, the RoCoF for the first 0.5 seconds following an RCC event at minimum SIR during 2017 operating year is presented for each of the four interconnections with no analysis or trending. Finally, for ERS Measure 4, a box plot of $IFRM_{A-C}$ and a scatterplot of C_n, and the pre-disturbance frequency (Point A) are presented for the 2017 operating year without analysis or trending.

In conclusion, Sub-Measure 4.2 was integrated into the SOR frequency response performance analysis, but other ERS Measures, even those selected by ERSWG for trending in the SOR reports, were not included. However, it is noted in the 2018 SOR that NERC PAS will conduct annual reviews of Reliability Indicators and that ERSWG Measures may be incorporated into the analysis at a later date (NERC 2018h). Since many of the ERSWG briefs were released three months prior to this SOR, it is possible that there may be some lag time before historical trending of the ERS Measures is possible.

Table 17. Integration of ERSWG Brief Recommendations with 2018 SOR Report

ERSWG Brief	Associated ERS Measure	Instruction from ERSWG Brief	Integration with 2018 SOR	Interpretation in 2018 SOR
Historical Frequency Trend	Measure 1	Interconnection SIR, at least 15-minute resolution	Plots of min/max daily SIR for each interconnection in operating year 2017	Not Provided
	Measure 2	RoCoF over 0.5 seconds for RCC event during low SIR	RoCoF with sensitivity analysis of load damping effect for each interconnection in operating year 2017	Not Provided
	Measure 4	Holistic Frequency Response Measure	Integration of Sub-Measure 4.2 with core M-4/BAL-003 analysis. Plots of Sub-Measure 4.2 and Sub-Measure 4.5c	Statistical trending of Sub-Measure 4.2 (2013-2017)
Historical Balancing Trends	Measure 6	CPS1 Analysis of 1-hour and 3-hour BA ramps	Not Provided	Not Provided

Adapted from (NERC 2018h)

B.5. Integration with NERC Long Term Reliability Assessment Report

Two key findings of the 2018 LTRA were supported by the tracking and trending of ERS:

- Key Finding 3: Frequency response is expected to remain adequate through 2022, and
- Key Finding 4: Increasing solar and wind resources require more flexible capacity to support ramp requirements (NERC 2018m).

Historical trending of SIR (ERS Measure 1) shows that there wasn't a large change in minimum inertia over the 2016-2018 operating years in the four interconnections (NERC 2018m). However, in the past eight years, nearly 90 GW of synchronous generation has been retired (NERC 2018m). Improved planning and increased operational experience with asynchronous resources have led NERC to conclude that FFR is an effective tool for keeping interconnection frequency within acceptable bounds and that "the application of FFR is expected to continue and support frequency when synchronous inertia is insufficient" (NERC 2018m). Furthermore, NERC finds that QI and TI, which have comparatively lower SIR due to their geographic size and resource mix, have effectively limited their future reliability risk from degraded inertia through operational procedures to manage real-time inertia (NERC 2018m). Consistent with the ERSWG's Forward-Looking Frequency Trends Technical Brief, the 2018 LTRA has the "first-ever, forward-looking interconnection wide assessment" of frequency response in the EI and WI (NERC 2018m). The results of this assessment show adequate SIR (ERS Measure 1), no negative trends in RoCoF (ERS Measure 2) and low likelihood of activating UFLS (Measure 4) through 2022 with the caveat that changes to the generator retirement schedule or economics could invalidate this assessment (NERC 2018m). Finally, NERC's positive outlook on frequency response is bolstered by the recent issuance of FERC Order 842, which is a first step toward assuring frequency response capability amongst all generation resources. Regulatory and policy action to support ERS was a key recommendation of the 2017 LTRA (NERC 2017d).

The 2018 LTRA conducts a forward-looking ramp capability assessment consistent with the framework described in the ERSWG's technical brief. NERC RAS identified ERCOT and CAISO as areas of interest for ramping analysis. The ramp capability assessment for ERCOT is focused on net-load ramps caused by high wind generation in the early spring mornings, where the balancing area has historically faced upward ramps of 11 GW (NERC 2018m). ERCOT has taken steps to improve wind forecasting to mitigate ramps and has self-funded research on wind net-load ramps to inform future planning processes (NERC 2018m). NERC appears to defer to the ERCOT's action on ramping challenges and does not present its own forward looking analysis and notes that ERCOT's ramp requirements can be "largely managed with improved forecasting" (NERC 2018m). The ramp capability assessment for CAISO notes that the current maximum 3-hour upward ramp of 14 GW attributed to an influx of solar DER exceeds earlier projections (NERC 2018m). Revised maximum 3-hour ramp projections through 2021 are presented. In both cases, NERC concludes that increasing levels of VERs will require the addition of more flexible capacity to reduce net-load variability (NERC 2018m). This flexibility can come in the form of increasing geographic diversity of resources and load, as is seen in CAISOs EIM, or the addition of dispatchable generation (conventional or variable), dispatchable loads, and energy storage (NERC 2018m).

The 2018 LTRA integrates many of the ERSWG recommendations on the topics of frequency response simulation and BA ramping assessment (Table 18). The 2018 LTRA also calls for additional work in ERS related topics. For example, reactive power requirements for transmission-connected devices is identified as an emerging reliability issue, which suggests that voltage support ERS may become a renewed area of focus for NERC's technical subcommittees (NERC 2018m). Finally, the 2018 LTRA recommends continued improvement of interconnection frequency response modeling for EI and WI and monitoring of ramping concerns and flexible capacity beyond California, continuing the trending of ERS measures (NERC 2018m).

Table 18. Integration of ERSWG Brief Recommendations with 2018 LTRA Report

ERSWG Brief	Associated ERS Measure	Instruction from ERSWG Brief	Integration with 2018 LTRA	Interpretation in 2018 LTRA
Forward Looking Frequency Trends	Measure 1	Development of EI and WI frequency response model and observation of ERCOT and HQ frequency response forecasting and control efforts	Historical (as expected in 2018 SOR) and forecasted interconnection SIR	"Appears to be more than sufficient inertia within all interconnections" (NERC 2018m)
	Measure 2		The "first ever, forward-looking interconnection-wide assessment" of IE and WI frequency response and updated summary of ERCOT/HQ practices (NERC 2018m).	"No negative trends identified" (NERC 2018m)
	Measure 4			EI and WI show "sufficient frequency response in future planning cases" (NERC 2018m)
Forward Looking Net Demand Ramping Variability	Measure 6	Non-dispatchable Resource Penetration Screen and Flexible Resource Screen for select BA; follow-up analysis if ramping concerns identified	ERCOT (wind) and CAISO (solar) were identified as BAs of interest for additional ramping capability assessment	ERCOT is funding own research on net load variability from their wind resources to inform real-time and planning processes; CAISO has projected ramps out to 2021. (NERC 2018m)

Adapted from (NERC 2018m)

APPENDIX C. SUMMARY OF NERC RELIABILITY STANDARDS RELATED TO ERS AND INTERCONNECTION

Note: This list of NERC Reliability Standards is limited those standards most closely related to ERS reliability building blocks (i.e., Frequency Support and Voltage Support) and requirements for interconnection. It is not the ERO's complete list of Mandatory Reliability Standards for the United States.

Name	Applicability	Title/Purpose	Comments
Resource and Demand Balancing (BAL)			
BAL-001-2	U.S.	*Real Power Balancing Control Performance* "To control interconnection frequency within defined limits" (NERC 2019b)	Frequency support; BA CPS1 balancing performance requirements
BAL-001-TRE-1	Regional, TI	*Primary Frequency Response in the ERCOT Region* "To maintain Interconnection steady-state frequency within defined limits" (NERC 2019b)	Frequency support
BAL-002-3	U.S.	*Disturbance Control Standard – Contingency Reserve Recovery from a Balancing Contingency Event* "To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event." (NERC 2019b)	Frequency support; "The entity experiencing a Reportable Balancing Contingency Event shall restore its ACE value to zero or pre-reporting ACE value, deploy contingency reserve to respond to events. Must develop, review and maintain an operating process to determine its *Most Severe Single Contingency* and make preparations to have contingency reserve equal to or greater than that. The entity must restore its contingency reserve to its Most Severe before the end of the contingency reserve restoration period" (NERC 2019b)

Name	Applicability	Title/Purpose	Comments
BAL-002-WECC-2a	Regional, WI	*Contingency Reserve* "To specify the quantity and types of Contingency Reserve required to ensure reliability under normal and abnormal conditions" (NERC 2019b)	Frequency support; Further quantifications of contingency reserve replenishment and transaction limitations. (NERC 2019b)
BAL-003-1.1	U.S.	*Frequency Response and Frequency Bias Setting* "To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting." (NERC 2019b)	Frequency support; BA FROs based on RCC and the UFLS first step
BAL-005-1	U.S.	*Balancing Authority Control* "This standard establishes requirements for acquiring data necessary to calculate Reporting Area Control Error (Reporting ACE). The standard also specifies a minimum periodicity, accuracy, and availability requirement for acquisition of the data and for providing the information to the System Operator." (NERC 2019b)	Frequency support; specifications for Reporting ACE
Facilities Design, Connections, and Maintenance (FAC)			
FAC-001-3	U.S.	*Facility Interconnection Requirements* "To avoid adverse impacts on the reliability of the Bulk Electric System, Transmission Owners and applicable Generator Owners must document and make Facility interconnections available so that entities seeking to interconnect will have the necessary information" (NERC 2019b)	Interconnection
FAC-002-2	U.S.	*Facility Interconnection Studies* "To study the impacts of interconnecting or materially modified Facilities on the Bulk Electric System." (NERC 2019b)	Interconnection; Reactive power controls should be tuned based on impact studies (SIS). Accurate models during interconnection process (NERC 2018j)
Modeling, Data, and Analysis (MOD)			
MOD-026-1	U.S.	*Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions*	Interconnection, model verification

Name	Applicability	Title/Purpose	Comments
		"To verify that the generator excitation control system or plant volt/var control function1 model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability." (NERC 2019b)	
MOD-027-1	U.S.	*Verification of Models and Data for Turbine/Governor and Load control or Active Power/Frequency Control Functions* "To verify that the turbine/governor and load control or active power/frequency control1 model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations." (NERC 2019b)	Interconnection, model verification
MOD-032-1	U.S.	*Data for Power system Modeling and Analysis* "To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system." (NERC 2019b)	Interconnection "Accurate steady-state, dynamic, and short circuit models should be provided to the planning coordinator" (NERC 2018j)
Protection and Control (PRC)			
PRC-024-2	U.S.	*Generator Frequency and Voltage Protective Relay Settings* "Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions" (NERC 2019b)	Frequency and voltage ride-through performance requirements
Transmission Planning (TPL)			
TPL-001-4	U.S.	*Transmission System Planning Performance Requirements* "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." (NERC 2019b)	Voltage support
Voltage and Reactive (VAR)			

Name	Applicability	Title/Purpose	Comments
VAR-001-5	U.S.	*Voltage and Reactive Control* "To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection." (NERC 2019b)	Voltage support
VAR-002-4.1	U.S.	*Generator Operation for Maintaining Network Voltage Schedules* "To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection." (NERC 2019b)	Voltage support, interconnection "The generating facility is required to maintain scheduled voltage (or power factor) per NERC VAR-002-4.1" (NERC 2018j)

Adapted from (NERC 2019b)