Reserve and Flexibility Products to Facilitate the Integration of Variable Energy Resources

A Survey of Recent U.S. and International Experiences

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Technical Update, December 2018

EPRI Project Manager

E. Ela

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

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Principal Investigators
M. Ortega-Vazquez
E. Ela
A. Tuohy
E. Lannoye
N. Singhal

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ABSTRACT

As the amounts of renewable energy sources in power systems continue to increase, the net demand (load minus renewable energy power production) exhibits larger degrees of variability and uncertainty. The required amounts and capabilities of reserves needed are evolving in order to accommodate the increasing penetration levels of renewable energy sources in an efficient manner. The goal is to ensure that there is sufficient headroom and ramping capabilities over multiple time scales to account for both variability and uncertainty of the net demand. Power system planners and operators are in charge of 1) determining the amounts of each type of reserves (including activation times and operation modes) and 2) introducing complementary new products needed to ensure power system reliability in a cost-effective manner.

This update summarizes some of the recent changes to methods used to determine the different reserve requirements and capabilities implemented by various balancing authorities, independent system operators, and transmission system operators across the world. The update also presents a brief overview of the various types of reserves used today and the way they are mirrored in the United States and internationally.

Keywords

Renewable energy sources
Reserves
Ramping product
Flexibility
Variable energy
Load

ACRONYMS AND ABBREVIATIONS

ACE	Area Control Error
AGC	Automatic Generation Control
BAAL	Balancing Authority ACE Limit
BM	Balancing Mechanism
CAISO	California Independent System Operator
CES	Clean Energy Standard
CHP	Combined Heat and Power
CPS	Control Performance Standard
CPS1	Control Performance Standard 1
CSP	Concentrated Solar Power
DA	Day-ahead
DCS	Disturbance Control Standard
DDP	Desired Dispatch Point
DTU	Demand Turn Up
EFR	Enhanced Frequency Response
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FRR	Frequency Restoration Reserves
IRF	Intermittent Resource Forecast
ISO	Independent System Operator
MFR	Mandatory Frequency Response
MISO	Midcontinent Independent System Operator
MTLF	Medium Term Load Forecast
NE	New England
NEPOOL	The New England Power Pool
NERC	North American Electric Reliability Corporation
NG	National Grid
NSI	Net Schedule Interchange
NSR	Non-Synchronized Reserve
NY	New York

NYCA	New York Control Area
NYISO	New York Independent System Operator
NYS	New York State
PV	Photovoltaics
RDT	Regional Dispatch Transfer
RES	Renewable Energy Sources
RRS	Responsive Reserve Service
RT	Real-Time
RTO	Regional Transmission Organization
SAPP	South African Power Pool
SB3	Senate Bill 3
SCADA	Supervisory Control and Data Acquisition
SEL	Stable Export Limit
SPP	Southwest Power Pool
STCR	Short-Term Capacity Reserve
STOR	Short-Term Operating Reserve
STRC	Short-Term Reserve Capacity
TMNSR	Ten-Minute Non-Spinning Reserves
TMOR	Thirty-Minute Operating Reserves
TMSR	Ten-Minute Spinning Reserves
TSO	Transmission System Operator
VER	Variable Energy Resources
WECC	Western Electricity Coordinating Council

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INTRODUCTION

Integration of Variable Energy Sources (VER)

Variable energy sources (VER), such as wind power generation and solar photovoltaic (PV) generation, have been increasing steadily over the last two decades. In particular, as of 2016, the annual average VER generation reached double digits in several systems such as CAISO, ERCOT and SPP with 21.0%, 13.8% and 16.1% respectively [1]. In the majority of these systems, the annual average VER penetration in 2016 was led by wind power generation, except for CAISO. In CAISO it was composed of 49.1% solar PV, 44.2% wind with, and 6.7% concentrated solar power (CSP) In SPP the maximum hourly penetration[1] of variable energy resources reached 62%, [2]; in CAISO it reached 64% and in ERCOT it has reached 54% in October 2017. Some of these statistics are summarized in Figure 1-1 as a function of year. Note that is expected that these numbers will continue increasing in the forthcoming years.

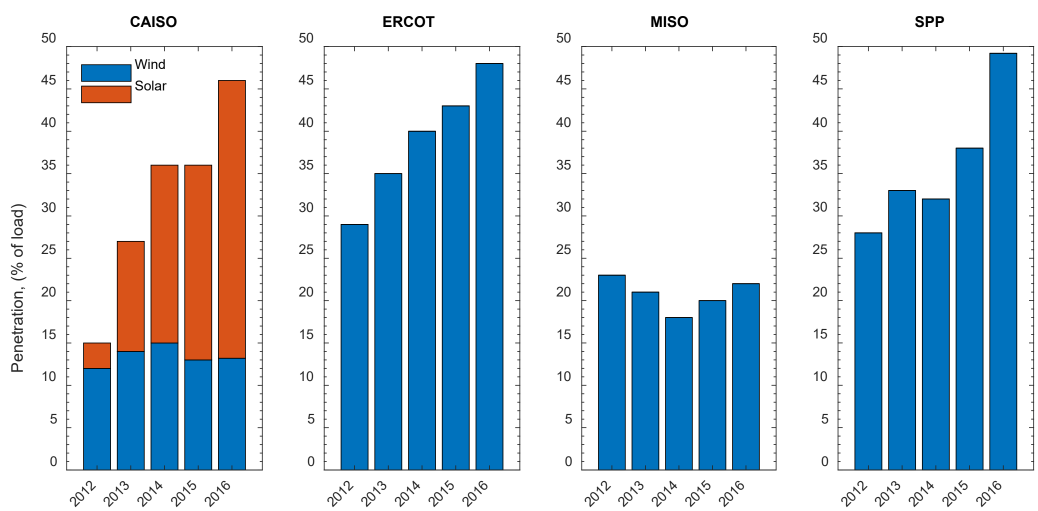

Figure 1-1
Maximum hourly penetration of wind and solar in different power systems as a function of time, based on [1].

The amount of VER has been steadily increasing over time across different systems in the US. This increase has been dominated by wind power generation, except in CAISO, where a large fraction of the VER increase has been dominated by solar power generation, see Figure 1-2.

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[1] Maximum hourly penetration refers to the maximum observed ratio of generation from a (set of) generation sources to load over a defined period (commonly a year) during a one-hour time interval.

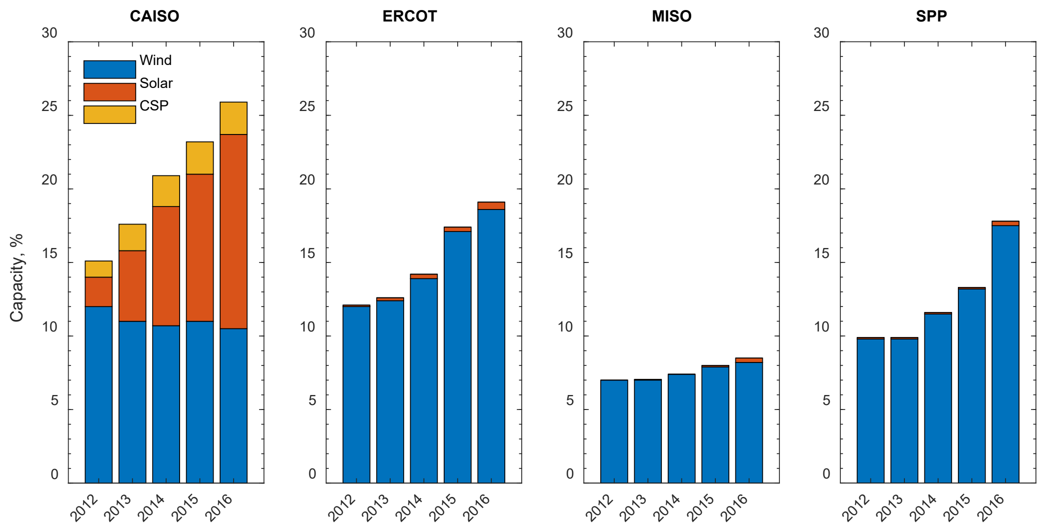

Figure 1-2
VER fraction of total capacity, based on [1].

The benefits of VER are well-known, and these include emission-free energy at zero-marginal cost of production, [3]. An important aspect of VER integration is the effect that it has on the residual or net demand (i.e., system-wide demand minus VER production) that needs to be accommodated by dispatchable resources (e.g., thermal generators). Figure 1-3, taken from [1], shows the demand and net demand of different US ISOs as a percentage of the system capacity for 2016. In this figure, and with the information shown in Figure 1-1, it can be seen that the systems with greater penetrations of VER, exhibit a net demand that is more heavily distorted when compared to the system wide-demand. Another important feature is that such distortion is directly correlated to the type of VER integrated in the system. For instance, in CAISO's case, in 2016, 55.8% of the total VER production comes from solar and 44.2% from wind. Therefore, the net demand is notably reduced during the periods in which solar irradiance is available (0600-1800 h). On the other hand, in systems in which the dominating VER resource is wind, e.g., ERCOT, MISO, SPP, the resulting net demand is offset over all hours of the day.

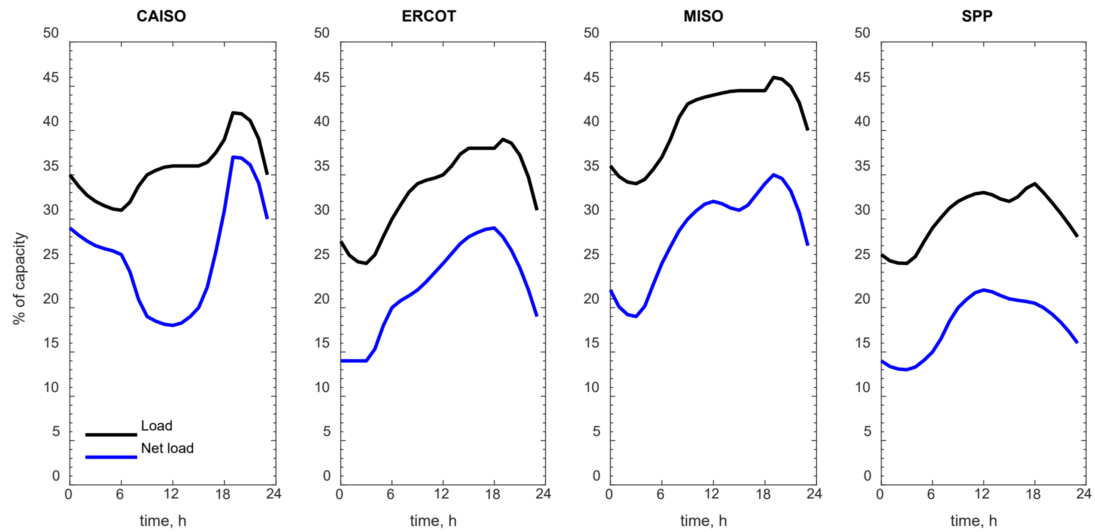

Figure 1-3
Qualitative percentage of net demand with respect to the total system capacity as a function of time for different US ISOs, based on [1].

The most important aspect of integrating VER is that, as any weather-driven resource, the power production from these sources is characterized by high levels of variability and uncertainty, [4]. Such variability and uncertainty has created unique challenges for power system operators and planners since the rest of the power system needs to possess greater agility to re-adapt to the new operating point. Furthermore, the operating plans drawn in day-ahead must allocate enough recourse in order to maximize the VER production while maintaining strict levels of reliability, at a minimum operating cost. In order to meet these specific needs, many regions are adjusting their reserve requirements across all regulation intervals and are proposing new operating products such as the flexible ramping capability.

The next subsection discusses the basic definitions of the various reserve types, how they map among different US and international power systems, as well as provide the basic generic definition of the ramping capability product.

Operating Reserve Types Considered by Balancing Areas

Operating reserve defines the active power capacity that is held above or below the power schedule of the system resources, to be used in case of an event or condition that occurs after the schedules are given [5]. Different operating reserves are needed for different reasons and terminology differs from region to region (see for instance [6]). Figure 1-4 shows a taxonomy of operating reserve with respect to whether they are event driven or not. Within these two groups they are further categorized based on existing (e.g. regulating, contingency, etc.) and evolving services (e.g. ramping, flexibility).

Operating reserves are typically held at a balancing area level, although it also can be shared across multiple balancing areas. Balancing areas are regions that contain generation, transmission and/or loads within a metered boundary area that must maintain the balance of generation and load within the metered boundary. In North America, these are managed by a Balancing Area Authority who maintains load/supply balance.

Operating reserve capacity can be defined by its reason for usage. For example, some operating reserve is used for large events, while others are used for normal balancing efforts that are not captured by energy schedules. The speed of response is also a characteristic in the type of operating reserve, some requiring rapid response, while others may require slower yet sustained response. Other characteristics include the direction of response to hold: upward, downward, or equal amounts of both, the technology requirements needed: for example, autonomous frequency response capability, automatic generation control, online or offline.

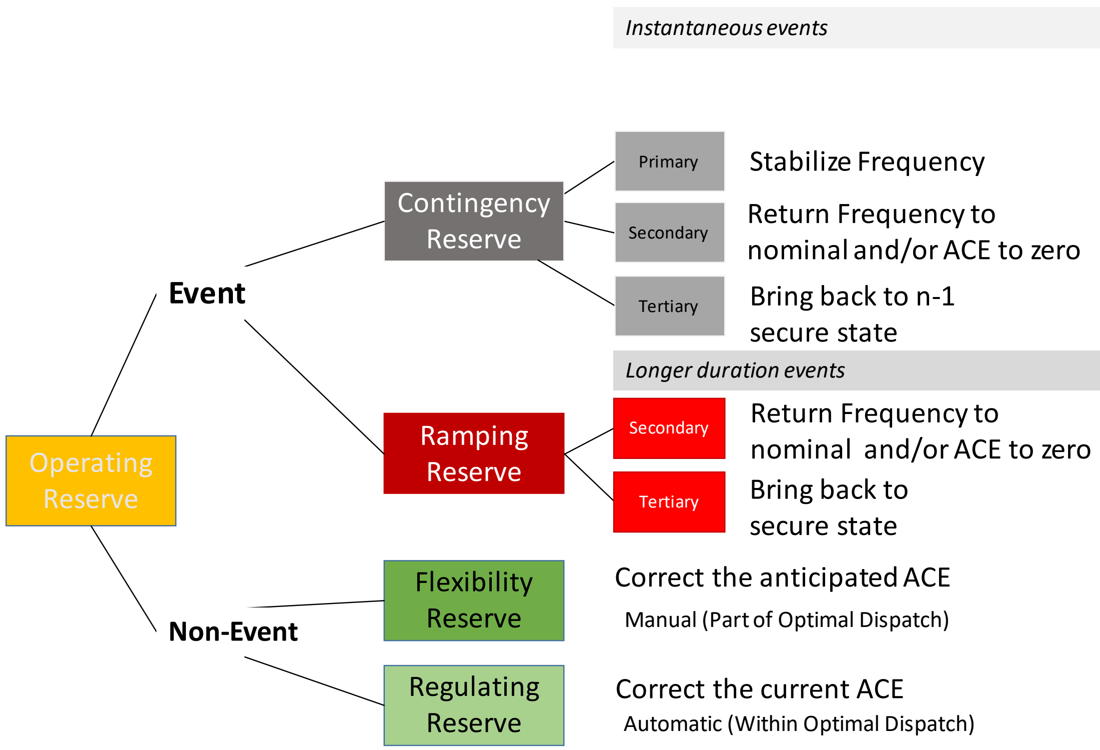

Figure 1-4
Different forms of operating reserve used for different purposes

With respect to time, the provision of reserve can be divided into three main response periods, as shown in Figure 1-5. In this example different regulation intervals as a function of time can be observed, and these are summarized as follows, [6], [7]:

1. **Inertial response**: In this period the rotating masses of the synchronous generators act to overcome the immediate imbalance between power supply and demand system demand.
2. **Primary response:** In this period, the response is provided by local automatic control that adjusts the active power production of the generating units (driven by the governor control, [8]) and the consumption of controllable loads to restore the balance between demand and generation (as fast as possible) and arrest the frequency deviation following a system perturbation (e.g., contingency or large deviation).
3. **Secondary response:** In this interval, a centralized automatic control adjusts the active power production of the generating units (driven by the automatic generation control, AGC) to restore the frequency and interchanges to their target values following an imbalance. While primary control limits and stops frequency excursions, secondary control brings the

frequency back to its target value. Each balancing area is responsible of maintaining its generation-demand balance; therefore, only the resources that are located in the area where the imbalance originated typically participate in this control.

4. **Tertiary response:** This is the period where the manual adjustments to the dispatch and commitment of resources takes place. This control is used to restore the primary and secondary frequency control reserves, to manage congestions in the transmission network, and bring the system back to a secure state in preparation for a subsequent contingency event.

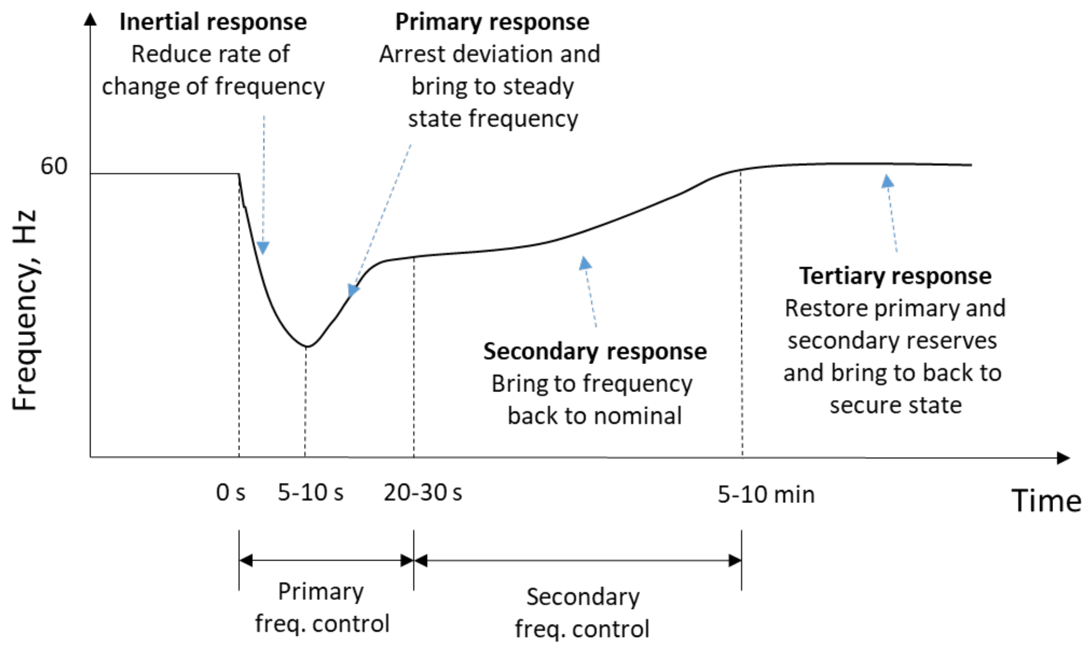

Figure 1-5
Frequency and activation of reserves in different regulation intervals, after a major generation outage

In Europe, ENTSO-E uses a classification of reserve products based on functionality (e.g. frequency containment reserve, frequency restoration reserve, and replacement reserve). Also, in the US, specific definitions for the different types of reserve and products are used in each system. NERC classifies the reserves depending on whether they are event driven or not, and within these two groups further classification is made depending on the speed of the response, [9], [10], and equivalents to the main regulation intervals have been presented, e.g. [6]. Some generic definitions include:

- **Frequency responsive reserve**: This is the amount of reserve that is automatically responsive to locally sensed frequency deviations and that stabilizes frequency.
- **Regulating reserve**: This reserve type is provided by synchronized resources on Automatic Generation Control (AGC), and they are used to address the fast up and down variations in demand and generation that contribute to energy imbalance. Variable generation increases short-term imbalances between generation and load, and regulation is used to correct these imbalances.

- **Spinning reserve**: This reserve is provided by synchronized resources, that can start decreasing or increasing the production in response to a system contingency or large deviation. Typically, this reserve should be able to respond within 10 minutes and its deployment is manual (i.e., typically manual and based on re-dispatch of the available generation and/or controllable demand).
- **Non-spinning reserve**: Similar to the spinning reserve but provided from generation that can be started-up and synchronized quickly to respond, within equivalent time ranges as the spinning reserves.
- **Replacement or supplemental reserves**: Supplemental reserves are used to restore spinning and non-spinning to their pre-event status. Typically, these reserves are required to respond within 30-60 minutes.

The basic definitions and categories of reserves can be summarized graphically as shown in Figure 1-6.

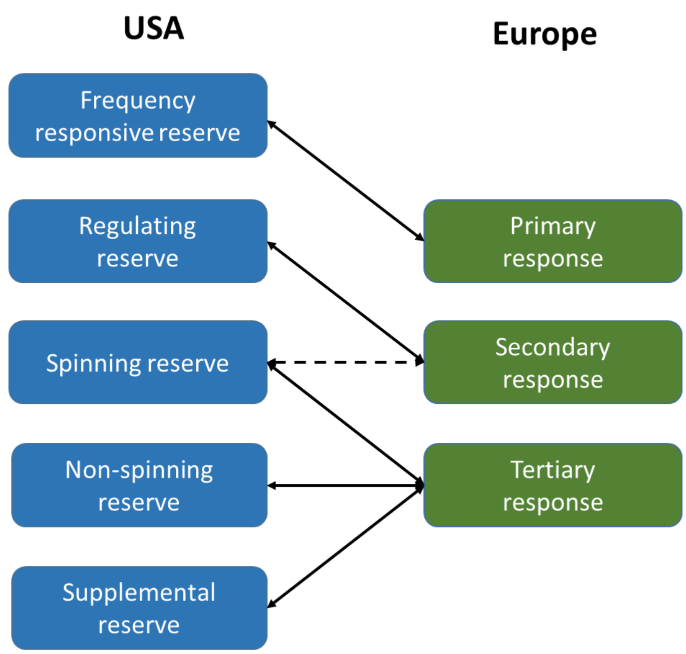

Figure 1-6
Reserve products in the US and Europe

Note that in Figure 1-6 there is a link between "spinning reserve" and "secondary response." This is because the secondary response in Europe is typically described as bringing the frequency back to nominal, and in the US the term "spinning reserve" is often used to describe the service that does that.

2

RESERVES AND FLEXIBILITY PRODUCTS IN U.S. SYSTEMS

Southwest Power Pool (SPP)

SPP had about 15,200 MW of installed VER (mainly wind) capacity within its region in 2016 (about 18.1% of its total generation capacity and 16.1% of its annual total generation). It has had an instantaneous penetration of close to 60% of its load being provided by wind generation on March 16th, 2016.

Reserves

In SPP, more than in other systems, the penetration of wind power generation has been increasing substantially. Recently, SPP registered a 60% penetration record. On the morning of Friday March 16, at 0345 h, wind accounted for 13,928.94 MW of the system's total load of 22,998.71 MW; which is equivalent to a penetration level of 60.56%. Such cases are not isolated. SPP reported that such an event was among nearly a dozen it has seen in the previous 90 days, [2]. Under the light of the increasing penetrations of VER in SPP, the reserve requirements and flexibility products are being readjusted in order to have sufficient recourse to respond to deviations. In general, SPP has a number of categories of operating reserves, similar to all other balancing areas in the US. The reserves are pooled from a diverse group of utilities and transmission companies in 14 states, under SPP's footprint. Reserves in SPP, similar to other regions, include reserves for normal operating conditions like regulation, as well as reserves to respond to large unforeseen events such as contingencies and large deviations.

The regulation up and down requirements are calculated using four components, [11], [4]:

1. Load magnitude (accounts for most of regulation requirements)
2. Load variability
3. Intermittent resource magnitude: Based on total forecasted wind/solar MW for the hour, average around 14% of regulation requirement.
4. Intermittent resource variability: Based on forecasted hour to hour change in wind/solar MW. Average around 3.5 % of regulation requirement.

Regulation in particular has been impacted by recent increased wind penetrations. SPP bases their reserves on both the magnitude and variability of load and VER. Until recently, only wind was considered, and though solar is now also considered it is currently too low to have an impact on requirements significantly [11]. The calculation used is based on determining a coefficient for each component as shown in Table 2-1 (the components are a load magnitude component, a load variability component, an intermittent resource magnitude component, and an intermittent resource variability component) and as shown in Equation (2-1). Magnitude components are simply just carrying a percentage of forecasted values as regulation. Variability components are intended to increase the amount of regulation carried in a given hour due to certain forecasted conditions. The variability components cannot be negative and, therefore, will not reduce the amount or regulation requirement derived from the magnitude components. All components are calculated each day for each operating hour on a rolling seven day ahead basis for both Regulation Up and Regulation Down. Further details are available in [12] and summarized in [4]. For example, the table below shows that in the first part of the year 2016, regulation was based on a combination of 1% of load magnitude, 1% of wind magnitude, 5% of the load variability and 10% of the wind variability, based on historical analysis. By studying what the actual requirements would have been, SPP decided to lower these amounts in mid-April to the amounts shown on the right-hand side; consecutively, reducing the regulation requirement by 20%.

$$RegUpRequirement = a^{up} \times MTLF(t) + b^{up} \times [MTLF(t+1) - MTLF(t)] + c^{up} \times IRF(t) + d^{up} \times [IRF(t+1) - IRF(t)]$$

Eq. 2-1

Where MTLF is the Medium term load forecast and IRF intermittent resource forecast.

Table 2-1
Coefficients used in SPP for reserve calculation in 2016, [11]

2016 coefficients	1/1-4/12	4/13-12/31
Load magnitude coefficient	0.01	0.008
Wind magnitude coefficient	0.01	0.008
Load variability coefficient	0.05	0.040
Wind variability coefficient	0.10	0.080

SPP ramp product

Since 2015, SPP has been assessing the possibility of creating a ramping product [13]. This product was inspired by those available at CAISO and MISO, [14], would also seek to attain the following benefits:

- **Increased available near-term ramp capability**: This would imply that units are held back when required in order to leave rampable capacity available to respond to future needs. As a consequence, there will be less real-time price volatility caused by ramp shortages, and also less frequent violations of operating reserve requirements.
- **Reduced operating costs**: Scheduling the ramping capacity in operating cycles where all resources are available, allows sourcing this capacity from the most economical ramping units and enabling them to respond during sudden changes in system requirements. This would also avoid uneconomic commitments to provide ramp when the system is in need and has limited options to choose from. Furthermore, since other reserve products would not be deployed to respond to this need, shortages of other ancillary services would be avoided.
- **Transparent pricing for the supply of ramp capability**: Instead of providing ramping capability by deploying reserves or committing additional generation and paying indirectly for the ramping capacity, the provision of an explicit product also allows for more transparent pricing. In other words, paying the right amount for the right product delivered. In the case of ramping products, the sources would be paid the opportunity cost.

- **Long-term benefits of ramp product**: By explicitly scheduling and pricing the ramping product, the right economic and market incentives would be communicated to producers. This would in theory result in investments in agile generation that can produce not only energy and reserves, but also ramping capability.

Technically, the product would be similar to that of MISO, [13]:

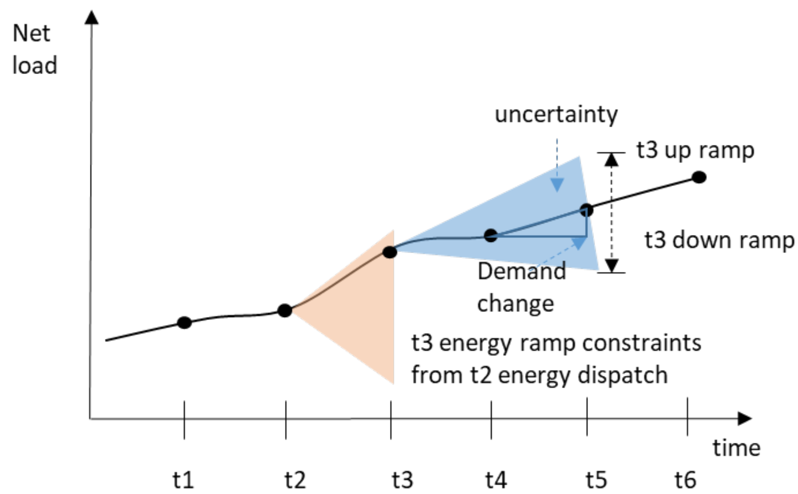

Figure 2-1
Schematic representation of the ramp capability needs, based on [16]

The proposal is for up and down ramp capabilities to be computed as the following:

- Up ramp capability = (t_5–t_3 net demand change) + uncertainty factor
- Down ramp capability = –1×(t_5–t_3 net demand change) – uncertainty factor

As things stand, SPP has and continues to get prepared for deeper penetrations of renewable energy sources and in particular for solar, as it is the one that has the capability of distorting the net demand shape more dramatically. This process of preparing includes evaluating mechanism for participation of storage energy resources as well as ramping products, [15].

Midcontinent ISO (MISO)

MISO had about 15,500 MW of installed VER (mainly wind) capacity within its region in 2016 (about 9.0% of its total generation capacity and 6.9% of its annual total generation). It has had an instantaneous penetration of close to 22% of its load being provided by wind generation on November 28th, 2016.

Reserves

The operating reserve provided in the Midcontinent ISO (MISO) is divided in two main groups: i) regulating reserve, and ii) contingency reserve, [16]. Each of these products is further subdivided as shown in Figure 2-2.

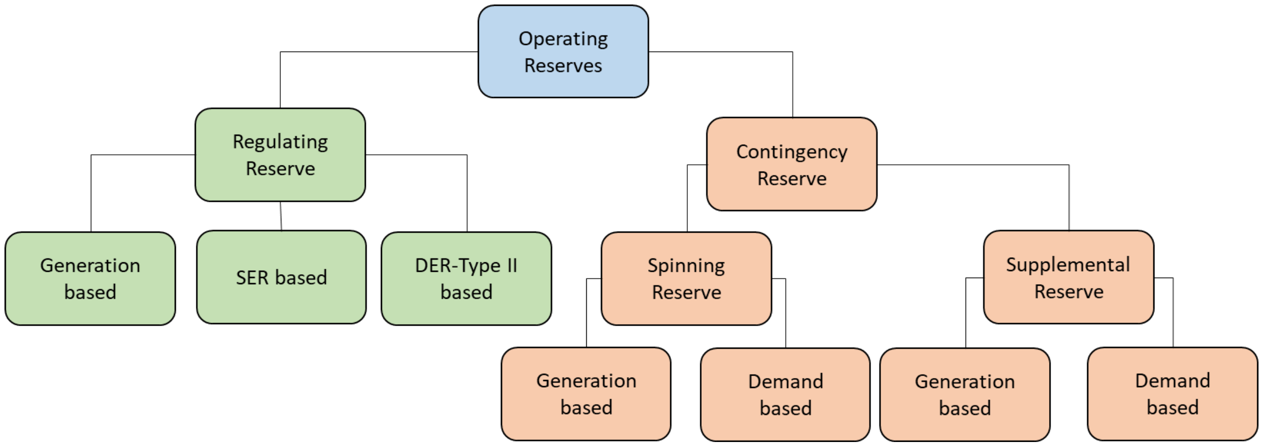

Figure 2-2
Operating reserve taxonomy in MISO, based on [16]

Regulating Reserve

The deployable regulating reserve (procured in up and down directions) is estimated automatically from the synchronized resources based on several technical aspects. These aspects include the available spare capacity within the required activation period (4 seconds to fully deployed in 5 minutes) as well as the active ramp rates and/or clearing of any other products of the resources. The amount of regulating reserves is determined on an hourly basis and the amounts for each hour are posted no less than 48 h prior the operating day. The system requirement for total Regulation Reserves across all zones varies between 300 MW and 500 MW, depending on system conditions. These requirements are not based explicitly on NERC standards, but rather on operational experience. These requirements are posted for both the day-ahead and real-time operating cycles. The amounts could be adjusted in real-time due to emergency operating conditions. The amounts are determined based on expected operating conditions and reviewed daily in order to ensure compliance with the Electric Reliability Organization and applicable Regional Entity standards.

Contingency Reserve

The contingency reserve, as the regulating reserve, must be deployable within the required deployment period and the available amounts are determined considering headroom and activation rates (10 minutes) of the available resources. The deployment period for this resource is governed by reliability standards, and in no case can be set to be greater than 10 minutes (ERO, BAL 002-0). This reserve can be contributed by spinning resources and qualified supplemental resources. It is important to note that spinning resources can also provide supplemental reserve through product substitution (higher quality resources replacing a lower one).

- **Spinning Reserves**: Can be provided by either generation resources or demand-side resources. There is a fixed requirement of 1000 MW for this reserve type.
- **Supplemental Reserves**: Can be provided by either generation resources or demand-side resources. This capacity does not necessarily need to be synchronized to the grid but must be able to synchronize within 10 minutes of receiving an instruction to do so. There is a fixed requirement of 1000 MW for Supplemental Reserves.

Short-Term Capacity Reserve (STCR)

MISO market planners outlined a potential 30-minute reserve product on December 2017, [17]. MISO currently addresses short-term capacity needs by committing quick start-up resources via out-of-market mechanisms and economic generation already online. However, MISO believes that such approach results in high uplift payments[2]. Therefore the idea behind the proposed new "Short-Term Capacity Reserve" STCR is to reduce uplift payments, in order to provide needed incentives for technologies to be available in certain locations within MISO, [18].

In essence, the STCR consists in allocating sufficient flexibility from resources that can respond within 30 minutes to address operating needs. These needs are categorized in MISO's footprint as follows, [18], [19]:

- **System-wide**: A major change in MISO, as in many other systems, is the ongoing and future changes in the mix of generation and their operating characteristics. The new generation mix might fail to deliver sufficient 30-minute flexibility without intentional definition and clearing of a discrete 30-minute capacity requirement. This is particularly relevant as deeper penetrations of wind and solar are expected in the near future, resulting in increased needs for flexibility. Furthermore, the relative changes in fuel prices can decrease the amount of unloaded flexible resources that have historically been available to respond to STCR needs. Additionally, the STCR would be used to recover from large deviations in ACE triggered by events not considered in the Disturbance Control Standard (DCS), [20]. The STCR would also be used to replenish other deployed reserves as well as to cover for the non-locational flexibility needs and response.
- **Regional**: MISO's Regional Dispatch Transfer (RDT) obligation limits energy transfers between the North/Central and South regions. Under a settlement agreement between MISO, Southwest Power Pool (SPP) and the joint parties[3], MISO's inter-regional dispatch flows can exceed the contractual limits, or RDT limits, following a contingency, but must be restored within 30 minutes. Although violating these obligations is not a physical operating limit of the system, MISO must ensure sufficient flexibility is available to ensure post-reserve deployment inter-regional dispatch flows respect RDT limits. Therefore, at a regional level the STCR would aid in managing regional transfers, as well as aid in locational flexibility needs and response.
- **Local (load pocket):** Load pockets are local areas with limited availability of flexible resources, which are also constrained by transmission capacity and/or voltage issues that limit import from surrounding areas. Due to the import limitations and lack of flexible resources, MISO must augment its normal practices and secure these local areas for the loss of two system elements, either generation or transmission. This ensures availability of sufficient flexibility to prevent extended overloads of transmission facilities, which may result in load shed to avoid violating reliability criteria in the event of a contingency.

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[2] MISO incurred about $35 million in Revenue Sufficiency Guarantee (RSG) payments for Regional Dispatch Transfer (RDT) and load pocket STCR needs in 2017 and much more in some previous years.

[3] The joint parties include Southern Company, Tennessee Valley Authority (TVA), Associated Electric Cooperative (AECI), Louisville Gas and Electric (LG&E), Kentucky Utilities Company (KU) and PowerSouth Energy Cooperative.

Therefore, at load pocket level the STCR would increase reliability and aid in providing local flexibility needs and response.

The STCR is also complementary to the existing suite of reserve and ramping products in MISO, specially under the light of their characteristics, [18], [19], see Table 2-2.

Table 2-2
Current MISO Ancillary Service Products

<table>
<tr><th>Product</th><th>Issue addressed</th><th>Activation time</th><th>Requirement source</th></tr>
<tr><td>Regulating Reserves</td><td>Continuous imbalance due to normal generation/demand variations</td><td>Seconds</td><td>NERC BAL-001-2</td></tr>
<tr><td rowspan="2">Contingency reserves
(spin and supplemental)
Ramp product</td><td>Disturbance triggered by contingency that meets the DCS threshold</td><td>10 minutes</td><td>NERC BAL-002-2(i)</td></tr>
<tr><td>Uncertainty due to normal and energy and supply variation</td><td>10 minutes after target dispatch interval, see Figure 2-4.</td><td>Good utility practice</td></tr>
</table>

In contrast, the STCR needs would be driven not only by system-wide needs, but also regional and local needs as explained before. Also, adding the STCR to the MISO's markets and co-optimizing Short-Term Reserves with energy and other ancillary services is expected to improve market dispatch and commitments. Key attributes of the proposed Short-Term Reserve product include the following:

a) Online and offline capacity eligibility
b) 30-minute ramp or start-up response time
c) Co-optimization with energy and ancillary services products
d) Location based requirements

MISO expects the inclusion of models for STCR needs and the product itself in MISO's commitment and dispatch engines will lead to more efficient results than the current sequential analysis approach. Introducing a product that explicitly establishes STCR requirements in MISO's markets will also provide local market prices that better reflects the value of STCR needs in the market dispatch, adequately address STCR reliability needs, and provide more transparency to the market, [18].

MISO assessed three options, Short-Term Reserve product, expanded use of Contingency Reserves, and enforcement of additional energy dispatch constraints, and concluded the Short-Term Reserve product is better suited for reliably addressing MISO's STCR needs in an efficient and transparent manner.

Ramp Capability Product

An additional ancillary product termed "ramp capability product" is scheduled as a complement to the other operating reserves, [21], and went live on May 1, 2016, [22]. This product is scheduled in upward and downward directions independently and it is designed to accommodate the expected net demand changes and additional uncertainty around forecasted quantities, [1], [23], [24]. The product is incorporated in each stage of the energy and ancillary services clearing processes (i.e., DA and RT), [25], Figure 2-3. The contribution of each of the units towards the provision of this service is limited not only by the operating limits but also by its ramp rates over the deployment time. The ramp capability product acts by prepositioning resources so that adequate ramp is available in subsequent dispatch intervals, Figure 2-4. In MISO, zonal ramp capability requirements are not required since post-deployment constraints ensure that the cleared ramp capability is deliverable to the load without violating transmission constraints after deployments, [16]. The allocation of the ramp capability products is performed on a co-optimization framework of existing energy and ancillary services. These additional ramping capabilities are enforced as additional inequality constraints that need to be satisfied.

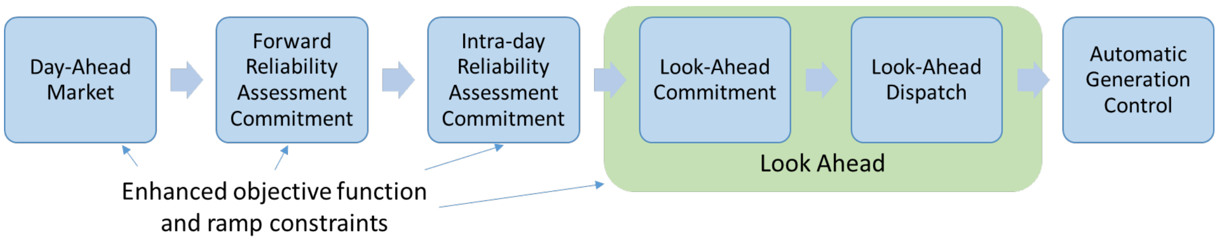

Figure 2-3
Integration of ramp capability product in MISO's scheduling processes

In particular, the economic benefits of pre-positioning generating resources in DA to schedule sufficient ramps to follow the net demand and to cover for uncertainties in RT, attains the following benefits, [23]:

- Reduction in RT price spikes (since ramp shortages are the most common cause of short-term scarcities)
- Reduction in RT price volatility
- Improvement in DA-RT price convergence
- Reliability by having better position ramp capability to meet changing net demand
- Reduction in the total operating cost of the system
- Transparent price signaling for investing in flexible supply-side resources

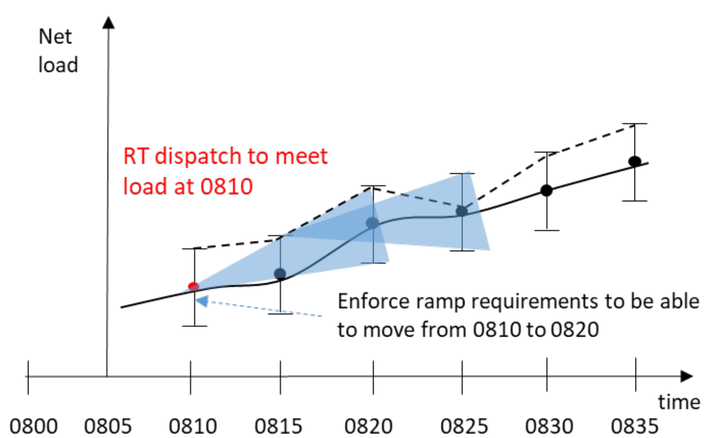

Figure 2-4
Ramping evolution to meet demand considering uncertainty in subsequent periods, look ahead

MISO sets the System-Wide Up and Down Ramp Capability Requirements based upon the following components:

- **Net Load Uncertainty**: Is a calculated value based on load forecast error, wind generation forecast errors and dispatchable resources not following set points. This calculated value is fixed for the up and down directions and applies to all case types for all intervals in the Day Ahead and Real Time Markets.
- **Net Load Change**: Is a calculated value based on load forecast change, wind generation change and Net Scheduled Interchange (NSI) change. The Real-Time Market uses a deploy time window of 10 minutes. The Day-Ahead Market and other forward processes scale the 10-minute window used in real-time to a deploy time window of one hour.

ISO New England (ISO-NE)

The ISO New England had about 1,900 MW of installed VER (mainly wind) capacity within its region in 2016 (about 5.8% of its total generation capacity and 3.1% of its annual total generation). It has had an instantaneous penetration of close to 8% of its load being provided by wind generation on December 30th, 2016. The ISO-NE as other ISOs has its own taxonomy of reserve products as described below under the following headings, [26].

Reserves

- **Regulation reserve**: The regulation reserves must increase or decrease the active power output in response to automated signals from the system operator (SO). The resources that respond to the automated signals to provide regulating reserves should be able to do so every 4 seconds. ISO shall maintain a portion of its Synchronized Capability on Regulation sufficient to satisfy the NERC Control Performance Criteria. Additionally, these requirements vary hourly, daily and seasonally, [27].
- **Ten-Minute Spinning Reserves (TMSR):** The ten-minute spinning reserves refers to the synchronized capacity to the system that can be fully deployed within ten minutes from being instructed.
- **Ten-Minute Non-Spinning Reserves (TMNSR):** As in the case of the ten-minute spinning reserve, this reserve should be able to convert the offered spare capacity within 10 minutes from being instructed. The main difference with respect to the ten-minute spinning reserve is that this resource does not need to be synchronized with the power grid. In terms of requirements, the combined requirements for TMSR and TMNSR must be greater or equal to the capacity of the single largest system contingency times a contingency adjustment factor for the most recent operating quarter. Regulation reserves that are available within 10 minutes can also contribute to this requirement. As a baseline, 100% of the total ten-minute reserve capacity must be TMSR, however, this requirement may decrease as low as 25% at the discretion of the SO. This process is outlined in [26].
- **Thirty-Minute Operating Reserves (TMOR)**: Thirty-minute Operating Reserves must be able to convert their capacity into generation within thirty minutes of receiving a signal from the system operator, but do not necessarily have to be synchronized with the grid. The TMOR requirement is equal to 50% of the second-largest system contingency. Excess TMSR and TMNSR may also contribute to meeting this requirement.

Discussion on Ramping Capabilities and Alternatives

In ISO-NE, historically, the system's ramping capability was occasionally too low during periods of rapidly increasing load since ramping needs were driven by steep net load increases, especially in winter mornings and before evening peaks, [28]. Currently, the actions to respond to these events are manual and require operators to move slow-ramping generators out-of-rate (upward) for 2-4 hours. They termed this response as "pre-ramping" since it involved slow-ramping units to be moved early. Two manual actions are used for this pre-ramping process in ISO-NE: i) Desired Dispatch Point (DDP) method; ii) Reserve bias method. In the former, the SO sets a higher DDP so that the dispatch pre-positions higher ramps in advance, and in the latter the SO increases the operating reserve requirements to get a similar effect. However, these ad hoc manual actions only reflect the SO's beliefs of the expected uncertainty and the consequences are: i) distorted energy prices; ii) distorted dispatched quantities; iii) higher overall operating cost; and iv) more out-of-market payments.

Alternatively, a multi-period dispatch could be used to enforce the ramping requirements implicitly by adding advisory look-ahead periods in the dispatch process (similar to CAISO and NYISO). In this approach only the first period schedules and prices are typically binding, and the advisory periods would not be considered in the settlement process. While this option offers some solution to the problem in terms of avoiding reserve shortages, they also have important market impacts as it can under-compensate/overcompensate resources, and it can also undermine the dispatch following incentives, [28].

An alternative could be a ramping product that enforces the ramping needs explicitly and has its own prices. As in CAISO and MISO, the ramping product would account for both, inter-interval variability and uncertainty. In [28], the author explored the possibility based on CAISO and MISOs' existing flexible ramp and ramping capability products, respectively, Figure 2-5.

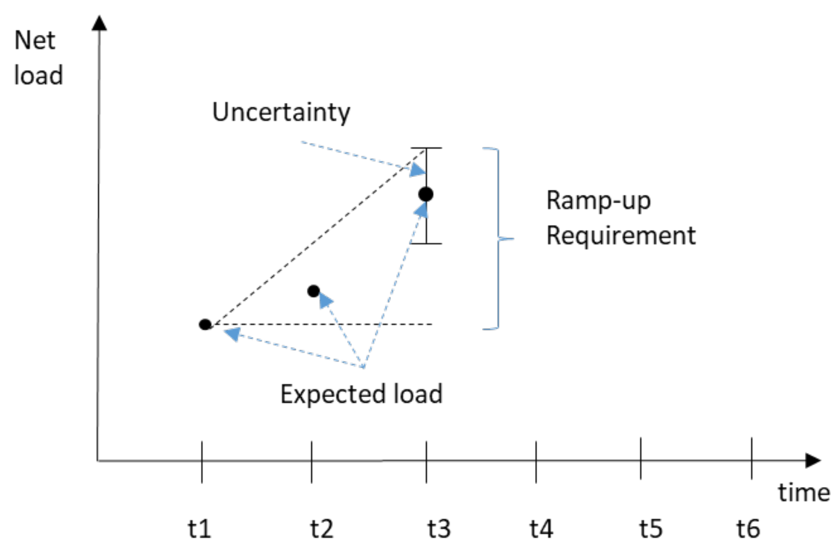

Figure 2-5
Illustration of the ramping product, based on [28]

As stated by ISO-NE, the advantages of introducing a ramping product are: it can help preserve ramping capabilities as well as to avoid reserve violations; it would also have explicit market price for ramping capability; and that the requirements can incorporate uncertainty in net load over the ramp product time horizon. On the other hand, ISO-NE concluded that the product: lacks clear incentives from ramp product prices (prices/payments are based on the product implementation, which does not match the product definition); the number and horizon of ramp products is highly dependent on system conditions and may need to be changed over time; ramp products cannot ensure feasibility if the system is ramping over multiple intervals.

New York ISO (NYISO)

NYISO had about 1,900 MW of installed VER (mainly wind) capacity within its region in 2016 (about 4.7% of its total generation capacity and 2.9% of its annual total generation). It has had an instantaneous penetration of close to 13% of its load being provided by wind generation on October 23rd, 2016.

Reserves

As in other ISOs, the reserves products in the New York (ISO) are within two main groups: i) regulation; and ii) operating reserve service, [29].

Regulation services are required to maintain a continuous balance between generation and load at all moments. These services also assist in maintaining the scheduled interconnection frequency at 60 Hz. This service is accomplished by committing generators including limited energy storage resources and demand side resources (regulation service suppliers), whose output can be increased or decreased in order to maintain the balance. In NYISO, the regulation requirements are consistent with meeting criteria established by NERC Control Performance Standards, which may vary hour by hour and by season.

Other operating reserves consists of backup generation and/or demand response to respond to unforeseen events such as contingencies or large deviations within NYISO. In order to respond in a timely fashion, the reserves must be available from generators and demand side resources within the corresponding activation intervals. These reserves will then be itemized as follows:

10-Minute Spinning Reserve: Operating Reserves provided by qualified Generators and qualified Demand Side Resources located within the NYCA that are already synchronized to the New York State (NYS) Power System and can respond to instructions from the NYISO to change output level within 10 minutes. Spinning reserve may not be provided by Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as a single aggregate unit.

- **10-Minute Non-Synchronized Reserve (10-Minute NSR)**: Operating Reserves provided by Generators that can be started, synchronized, and loaded within 10 minutes. These reserves are carried on quick-start units, such as jet engine type gas turbines. Operating Reserves may also be provided by Demand Side Resources where the demand response is provided by a Local Generator or by Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as an aggregate unit.

- **30-Minute Spinning Reserve**: Operating Reserves provided by qualified Generators and qualified Demand Side Resources except Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit and dispatched as a single aggregate unit located within the NYCA that are already synchronized to the NYS Power System and can respond to instructions from the NYISO to change output level within 30 minutes.
- **30-Minute Non-Synchronized Reserve (30-Minute NSR):** Operating reserves that can be provided by Generators, Behind-the-Meter Net Generation Resources that are comprised of more than one generating unit that are dispatched as an aggregate unit, that can be started, synchronized, and loaded within 30 minutes. Operating Reserves may also be provided by Demand Side Resources where the demand response is provided by a Local Generator.
- **Total 10-Minute Reserve**: The sum of the 10-Minute Spinning Reserve and 10-Minute NSR. [NERC defines this as Contingency Reserve]
- **Total 30-Minute Reserve**: The sum of the 30-minute Spinning Reserve and 30-Minute NSR provided by Generators and Demand Side Resources that respond to instructions to change output or provide a demand reduction within 30 minutes.
- **Total Operating Reserve**: The sum of the total 10-minute reserve and the total 30-minute reserve.

In terms of requirements, these are set as follows:

- **Total Operating Reserve** must be greater than or equal to one and one-half times the largest single Contingency (in MW) as defined by the NYISO
- **Total 10-Minute Reserve** must be greater than or equal to the largest single Contingency (in MW) as defined by the NYISO
- **10-Minute Spinning Reserve** must be greater than or equal to one-half of the largest single Contingency (in MW) as defined by the NYISO
- **At all times sufficient total 10-minute reserve** is maintained to cover the energy loss due to the most severe Normal Transfer Criteria contingency within the NYCA or the energy loss caused by the cancellation of an interruptible import transaction (neighboring control area to NYCA) whichever is greater. In addition:
  - The NYISO may establish additional categories of Operating Reserves if necessary to ensure reliability.
  - The NYISO ensures that providers of Operating Reserves are properly located electrically so that transmission constraints resulting from either commitment or dispatch of units do not limit the ability to deliver Energy to Loads in the case of a Contingency.
  - The NYISO ensures that Capacity counted toward meeting NYCA Operating Reserve requirements is not counted toward meeting Regulation and Frequency Response Service requirements.

Electric Reliability Council of Texas (ERCOT)

ERCOT had about 19,200 MW of installed VER (mainly wind) capacity within its region in 2016 (about 19.1% of its total generation capacity and 13.8% of its annual total generation). It has had an instantaneous penetration of close to 50% of its load being provided by wind generation on March 23, 2016.

Reserves

ERCOT has its reserve products itemized as described below, [30]:

- **Regulation up**: These are the available headroom that can be deployed immediately in response to automated signals (AGC). The signals are sent in response to changes in ACE. For determining the regulation up requirements for a particular hour, ERCOT will take the largest of the 95th percentile of regulation up deployments for the same month of the previous two years, and the 95th percentile of the positive net load (load – wind – solar) changes for the same month of the previous two years. In order to consider the increased amount of wind penetration, ERCOT will calculate the increase in installed wind generation capacity. Then, depending on the month of the year and the hour of the day, ERCOT will add incremental MWs to the maximum values determined above, [30].
- **Regulation down**: This is the available footroom that can be deployed immediately in response to automated signals. The requirements for regulation down are calculated in a similar manner to those for regulation up but considering regulation down deployments.
- **Responsive Reserves (RRS):** Responsive Reserves must be able to respond quickly to changes in system frequency. This service can be provided by generators and by load resources that are automatically interrupted within 0.5 second when system frequency decreases to 59.7 Hz. The amount of RRS procured from these types of Resources during any given hour is limited to 60% of the total RRS requirement for that hour, [30].

  ERCOT will procure amounts of RRS that vary by hour of the day and by month. These RRS amounts are published by month in six separate blocks covering four hour intervals. These amounts are based on the offline dynamic studies carried out at different inertia levels. The criteria in the studies was that there should be enough RRS such that for the trip of two largest nuclear units, system frequency should not reach under-frequency load shedding trigger (59.3 Hz). RRS requirements are set to l cover 70th percentile of historic system inertia conditions for each block of hours for the month; and uses the equivalency ratio for RRS between Load Resources and Generation Resources participating in RRS to establish final requirements for each block of hours. The equivalency ratio is a function of whether RRS are being procured. RRS requirements are increased by an additional; MW for periods when the 85th percentile of weighted average temperature is greater than 95 ^{o}F.
- **Non-Spinning Reserves**: Non-spinning Reserves must be able to become synchronized with the grid and ramp to a specified output level within 30 minutes, and generate at that level for at least one hour. Reserve capacity that is already synchronized with the grid can also provide this service, as can demand-side resources that can reduce their load. ERCOT will determine the Non-Spinning reserve requirement for every month of the year, six 4-hourly blocks in a day, using the 70th to 95th percentile (depending of the risk of net load ramping) of hourly net load uncertainty (6-hours ahead load forecast minus the forecast of total output from Intermittent Renewable Resource) from the same month and same 4-hourly block of the

previous three years. The risk of net load ramp is determined based on the change in net load over an hour divided by highest observed net load for the season. Periods where the risk of net load ramp is highest will use 95th percentile compared to 70th percentile for periods with lowest risks. Additionally, an incremental MW adjustment is included to account for the increase in RES capacity in the ERCOT system. The incremental MW adjustment to the Non-Spin value per 1000 MW is calculated as the change in 50th percentile of the historical wind over-forecast error for 4-hour blocks of each month in the past 5 years, which is then normalized to per 1000 MW of installed wind capacity.

Ancillary Services Redesign

A few years back, ERCOT proposed a redesign of its ancillary service products and markets. Such re-design was introduced as by the future ancillary services team, or FAST, which sought to look at the current set of ancillary services and determine whether the definitions and types were still valid for the current system needs. That was because the ancillary services were designed taking into account large steam generators as the predominant generation type [31], [32]. The evaluation of the revised ancillary services was therefore mostly motivated by new resources (20% of its total generation being VER), which have different characteristics and performance from traditional units, Figure 2-6.

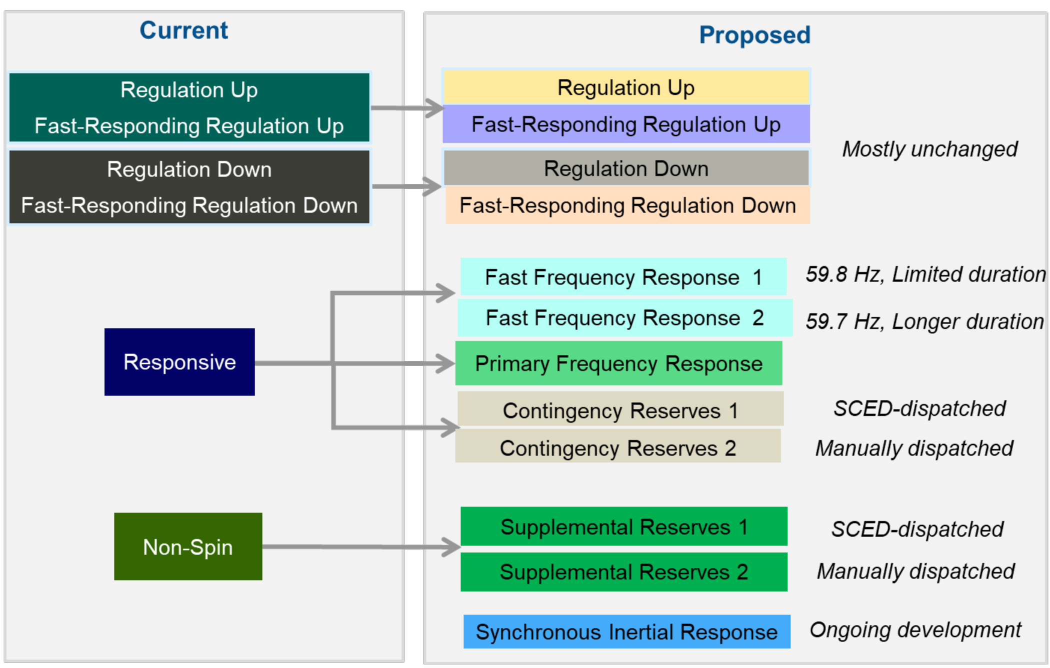

Figure 2-6
Current and proposed future ancillary services proposed, [31], [32].

The proposed FAS was not implemented, but considerations to accommodate the increased penetrations of RES are being considered. More details are is presented [32] and summarized in [4].

As of January 2018, there is a new proposal (Nodal Protocol Revision Requests, NPRR 863, [33]) for AS redesign being considered in the stakeholder process. The proposal is similar to those shown in Figure 2-6. The new proposal is shown in Figure 2-7.

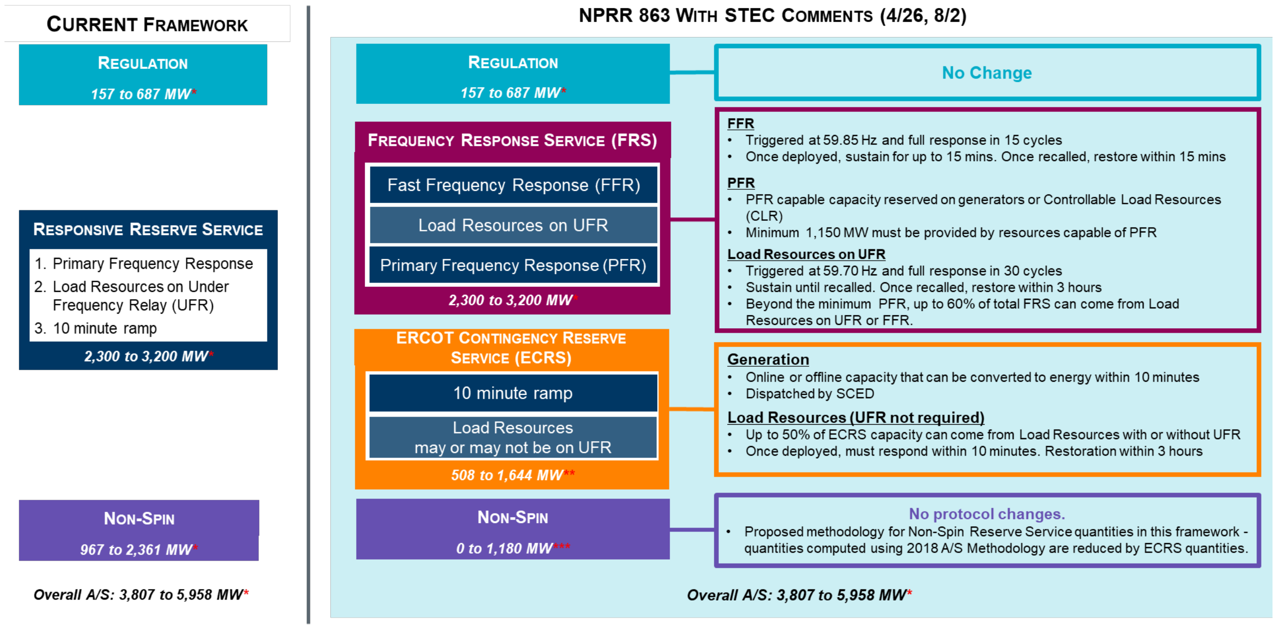

Figure 2-7
Current and proposed AS redesign, January 2018, [33], [34].

Revised Ancillary Services Requirements 2018

ERCOT revises its methods to determine the ancillary services requirements on an annual basis. This is important given the increase in the amount of weather-driven generation in the system, see Figure 1-1 and Figure 1-2. The general trends for each of the reserve services provided in ERCOT are, [30]:

- **Regulation Service**: The hourly average amounts of reserve for this service comparing 2017 to 2018 are similar, with slight decrements in the last three months for regulation up, and the last six months for regulation down.
- **Responsive Reserve Service (RRS):** The hourly average amounts of RRS showed a systematic increase in 2018 with respect to the quantities for 2017.
- **Non-Spinning Reserve**: This reserve showed some differences with respect to the amounts computed for 2017. In general, the trend was for greater amounts of this reserve in particular for January, April, July, and August. ERCOT proposed two changes to the method used to calculate this reserve:
  1. Include solar generation and solar forecast in the calculations for Net Load and Net Load Forecast (i.e., include effects of solar in Net Load Forecast error & Net Load up ramp risk calculation).
  2. Include an adjustment to account for additional over-forecast uncertainty from projected increase in installed wind capacity in 2018.

In general, the following two items summarize the revised ancillary services for 2018, [30]:

- ERCOT is not proposing any changes to the method for determining Regulation Service & Responsive Reserve quantities for 2018.
- ERCOT is proposing the two aforementioned changes to the method for determining Non-Spinning Reserve Service for 2018.

Duke Energy

Renewable energy goals established in North Carolina Senate Bill 3 (SB3), [35], in combination with the state tax credit, have spurred a rapid integration of solar power within the Carolinas service areas of Duke Energy. Furthermore, the sustained decreases in PV costs are expected to incentivize further integration of PV generation resources. The rapid increase in these resources has resulted into modifications to the methods used for reserve determination at Duke Energy.

Reserves

Duke Energy procures the reserve products described below [36]:

- **Regulating Reserves**: This reserve resource is used to respond to load and other resources (wind and solar generation) variability and is provided by synchronized resources capable of responding to AGC signals. This reserve must be available within 10 minutes.
- **Contingency Reserves**: This reserve is used to respond to unforeseen events such as the sudden loss of generating resources. It is composed by a mix between online (i.e., synchronized) and offline (standing) resources and must be available within 10 minutes of an event.
- **Operating/Back-Standing Reserves**: This reserve is used to respond to changes in system resource availability, and as in the case of contingency reserves, it is provided by a mix of online (synchronized) and offline (standing) resources. This reserve must be available within 30-60 minutes of an event, depending on the season.

Reserve Requirements Including VER Variability

Under shallow penetrations of VER, the reserve requirements can be computed using rules of thumb for discrete events such as contingencies, and the expected load pattern for continues power balance. For instance, consider the regulating reserve requirements, [36]:

- Duke Energy computed the reserve requirements based on forecasted load out 10-minutes. This works by reading last 4 hours load data with 30 sec. resolution, and then extrapolating using a cubic spline to project the demand for the next 10-minute. The requirement is then estimated as the difference between the load level at time t+10 and the load level at time t. These requirements were also bounded between [1.5× load at time t+10, 0.5× load at time t+10]:
  - RegUp = $\min(\max(\Delta_{Load}, 0.5\times L(t+10)), 1.5\times L(t+10))$
  - RegDn = $\min(\max(-\Delta_{Load}, 0.5\times L(t+10)), 1.5\times L(t+10))$

However, as the variability of the net demand increases and the penetrations of VER deepen, the method to estimate the reserve requirements was modified to take into account the increased variability as follows:

- The adjusted regulating reserve requirements take into account the expected variability of VER:
  - $RegUp = \min(\max(\Delta_{Load} - \Delta_{VER}, 0.5\times L(t+10)), 1.5\times L(t+10))$
  - $RegDn = \min(\max(-\Delta_{Load} + \Delta_{VER}, 0.5\times L(t+10)), 1.5\times L(t+10))$

These reserve requirements should then be enforced in the scheduling processes, and Duke Energy is also expecting to integrate longer forecast outlooks as well as weather data.

3
EUROPEAN TSOS AND OTHER INTERNATIONAL EXPERIENCES

Elia

The Belgian TSO Elia, as other TSOs, has the obligation of determining the reserve requirements to respond to unforeseen events in their system including contingencies and deviations from forecasted quantities. In particular, the types of reserves that are provided by ELIA include, [37]:

- **Primary Reserve**: Automatic adjustment of the active power output after detecting frequency fluctuations within 0 to 30 seconds. This service should be able to compensate for two simultaneous incidents (the loss of two 1500 MW production units). It is delivered up to 15 minutes after the incident.
- **Secondary Reserve**: Automatic upward and downward response that deploys between 30 seconds to 15 minutes and has the ability to be maintained as long as needed. It should be sufficient to substitute the primary reserve in the indicated time framework.
- **Tertiary Reserve:** The tertiary reserve enables Elia to cope with a significant or systematic imbalance in the control area and/or resolve major congestion problems. The tertiary reserve has two components:
  - The tertiary production reserve: Injection of extra capacity by producers who have signed a contract for tertiary reserve;
  - The tertiary off-take reserve: Reduction in off-take by grid users who have signed an interruptibility contract.

  Unlike the primary and secondary reserves, the tertiary reserve is activated manually at Elia's request. Any grid user whose facilities comply with certain technical requirements can sign a contract with Elia to take part in the tertiary reserve.

The amounts of the reserves are determined statically in a way in which they maintain a given level of risk under a given set of (adverse) conditions. However, static requirements do not capture the fact that risk changes as a function of system conditions, and thus time. In order to make the process efficient in terms of both, cost and reliability, Elia is considering adopting methods to determine the appropriate amounts of Frequency Restoration Reserves (FRR) dynamically in order to maintain (or even enhance) the level of system reliability at a minimum cost.

Dynamic Dimensioning of the FRR

Currently, Elia uses a static method to determine the needs for the FRR (primary contingency reserve) each year. This method quantifies the needs based on a statistical convolution of: the observed system imbalances; the prediction errors of incremental installed VER; and the forced outages of generating unit. However, due to the ever increasing amount of VER in their system and the integration of the Nemo Link, [38], (which is expected to affect the forced outage risk in the system), they are foreseeing an increment in the FRR needs. Acknowledging the fact that the needs for FRR would change as a function of system conditions (load to serve, expected VER production, generation commitment, etc.), they conducted a study to assess six potential methods to dynamically set the FRR requirements taking into account the derived system risk and the cost of procuring the FRR, [39]. The dynamic sizing is planned to be used for reserve before the DA market closure (18-36 hours ahead), in order to guarantee its availability. In other words, pre-positioning the commitment and dispatch of the available generation in DA with sufficient headroom and ramping capabilities to respond in RT.

The main drivers for the dynamic FRR are categorized as either:

i) **Prediction risks**: The first category explicitly acknowledges the fact that scheduling processes are based on predicted/forecasted quantities, and that the error of such prediction changes as a function of time and quantity being predicted. For instance, predictions over long horizons of time are more likely to have a larger error than those for shorter horizon of times. Also, predicting a lower number of variables like VER, is more likely to result in surplus of the forecasted quantity than in shortages. Equally, the error in predicting quantities such as solar generation during night periods (i.e., zero production) is lower than the predictions in the middle of the day.
ii) **Outage risks**: This second category acknowledges the fact that outage risks are a direct function of the DA schedule. That is, a generator that was not schedule cannot contribute to the outage risk. Therefore, outage risk is modeled as a quantity that changes through the day and is a function of the synchronized generation reliability. Similarly, this distribution would change when the interconnection between the UK and Belgium (Nemo Link) becomes active.

Explored Methods to Determine the FRR Needs

In the report, [39], six dynamic methods that incorporate the aforementioned risks are explored, for cases of expected system conditions in 2020 (extrapolated from 2016 historical data and VER projections), and a reliability target of 99.9% (i.e., the FRR should always cover at least 99.9% of the expected system imbalances). The methods considered are a natural evolution of the current practice, as well as enhancements to capture more modeling detail and exploit the available computational resources to date. The methods considered, and their characteristics are summarized in Table 3-1.

Table 3-1
Overview of the results of the six methods concerning methodologic feasibility, reliability, FRR needs reductions, robustness towards future system conditions, as well as the decision to selection for the Proof of Concept, [40]

Method	a. Feasibility	b. Reliability	c. FRR needs	d. Robustness	e. Selection
1. Outage Only	Yes	=	+	+	Yes
2. Extreme Cases	Yes	No	NA	NA	No
3. Manual Clustering	Yes	No	NA	NA	No
4. Quantitative Clustering*	Yes	+	++	++	Yes
5. Continuous Neighbors*	Yes	+	++	++	Yes
6. Neural Networks*	No	NA	NA	NA	No

* Indicates a method that includes advanced statistical approaches based on machine learning.

As it can be seen from Table 3-1, several aspects of the methods were considered. The following bullets summarize the findings:

a. The first column indicates the feasibility for implementation. In this case, it can be seen that all methods could be implemented without major complication except the one based on 'artificial neural networks.' This method encountered methodologic problems to integrate the outage and prediction risks.
b. The second column indicates the resulting system reliability. In this case, it can be seen that considering a method that only takes into account 'outages only' would result in equivalent reliability with respect to the status-quo (i.e., static approach), while 'quantitative clustering' and 'continuous neighbors' would result in increased reliability.
c. As for the impact on the FRR needs (third column), the 'outage only' method brings moderate benefits while marinating the same level of reliability. On the other hand, the 'quantitative clustering' and the 'continuous neighbors' result in greater (substantial) reduction of the FRR needs for both, up and down directions. Furthermore, the machine learning tools (methods 4 and 5) provide better reliability management by scheduling larger amounts of FRR during periods of higher risk and reducing these requirements during periods of low risk (e.g., see [40] and [41] for illustrative examples), which is something the static approach does not capture.
d. In terms of robustness, the simulations show that as the penetration of VER increases in the system the potential for dynamic approaches, especially those based on machine learning methods, increase. This is more evident when comparing results against the 'outage only' method. Results also show that the better performance of balancing markets reduces the magnitude of the FRR needs.
e. For the selection of the most adequate method(s), two criteria were considered: i) technical criterion which focuses on the reliability improvements only, especially during high risk conditions; and ii) economic criterion, which is expressed in terms of savings due to the FRR needs reductions. In terms of reliability improvements, methods 1, 4 and 5 show either the same levels of reliability or significant improvements (4 and 5); and in terms of cost, the same methods show benefits, although these are of greater magnitude when using methods 4 are 5. Therefore, these methods where considered for a proof of concept phase, [39].

Methods 1, 4, and 5 were considered for the proof of concept. The proof of concept consisted in developing prototypes for each of the chosen methods, and testing them in realistic contexts for 2020, taking into account the imports/exports of the NEMO-link. The results from this process showed again that the dynamic sizing methods strike a better balance between cost and reliability management, by increasing the FRR needs during periods of higher risk and reducing it during periods of lower risk. These results are more evident for the approaches based on machine learning techniques. In contrast, method 1 is able to maintain a predefined level of reliability, but its functionality is limited to reducing the FRR needs during periods of low risk.

Cost/Benefit Assessment

In this study, a cost and benefit analysis was also conducted to assess the business cases for the three methods under different scenarios and a case study for 2027. These studies showed the financial gains with respect to the reference scenario, and it was concluded that they should keep the three methods when moving towards an industrialization of the dynamic sizing method. Method 1 is estimated to bring a financial gain between 1.48 and 1.71 M€, while the machine learning methods are estimated to bring a financial gain between 2.51 and 2.97 M€. In terms of cost of implementation, including the project development and yearly recurrent cost a dynamic sizing, the implementation cost is estimated at 0.85 M€ to 1.1 M€ per year. Therefore, the expected benefits largely exceed the expected costs, and thus the report ends up recommending preparing for the implementation of dynamic sizing of FRR.

National Grid – United Kingdom

As in any electricity market, in the GB market supply and demand for electricity must be matched at all times. In the UK, this is primarily done by generators and suppliers that trade in the competitive wholesale electricity market. In general, the GB market can be described as operating in three phases, [42], Figure 3-1.

1. Forward Markets
2. The Balancing Mechanism
3. Imbalance Exposure

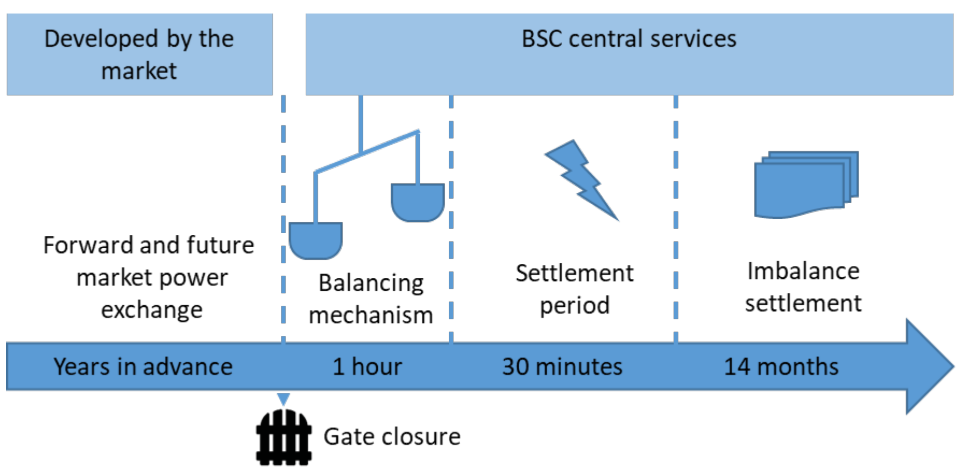

Figure 3-1
Trading and settlement in GB market, based on [43]

After the market closes, the system operator, National Grid (NG), has the responsibility of balancing supply and demand to accommodate any deviations that might occur. This balancing process takes place in the Balancing Mechanism, which is built based on offers to buy and sell electricity from generators and loads. This balancing process is procured through a number of different categories, which are summarized as follows, [44]:

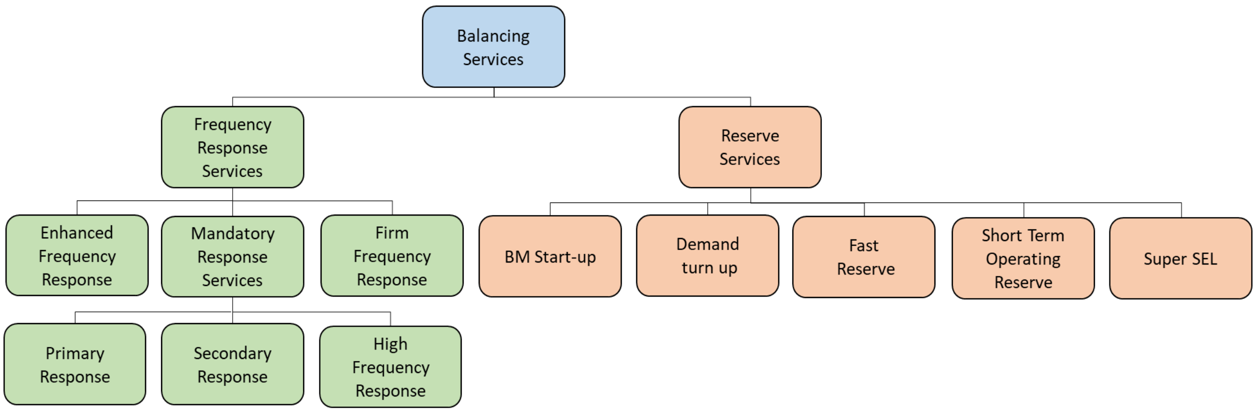

Figure 3-2
Balancing services in the UK, [44]

Each of the services shown in Figure 3-2 are described below.

Frequency Response Services

- Enhanced Frequency Response (EFR): Introduced in the second half of 2016, [45], this is a dynamic service where the active power changes proportionally in response to changes in system frequency. This service is aimed at improving the management of system frequency before contingency occurs to maintain system frequency closer to 50 Hz. EFR providers are required to have a minimum of 1 MW of response and a maximum response of 50 MW, either individually of via aggregation services. These resources should also be able to respond within 1 second to frequency deviations. Before the introduction of this product there was no market for very fast response balancing ancillary services. The introduction of the EFR has resulted in 200 MW, 4-year tender EFR grid-balancing that responds within 1 second of registering a frequency deviation, and was met principally by batteries, [46].
- Firm Frequency Response (FFR): These are services that can provide dynamic and non-dynamic response to changes in frequency:
  - Dynamic response: This is a continuously provided service used to manage the normal second-by-second changes on the system.
  - Non-dynamic response: is typically a discrete service triggered at a defined frequency deviation.

  There are three response speeds for this service:
  - Primary response: Response provided within 10 seconds of an event, which can be sustained for a further 20 seconds.
  - Secondary response: Response provided within 30 seconds of an event, which can be sustained for a further 30 minutes.

- High frequency response: Response provided within 10 seconds of an event, which can be sustained indefinitely.

- Mandatory Frequency Response (MFR): As the others, this is an automatic change in active power output in response to a frequency change. This service helps NG to keep frequency within statutory and operational limits. This service is also subdivided in primary, secondary and high frequency responses:
  - Primary response: Response provided within 10 seconds of an event, which can be sustained for a further 20 seconds.
  - Secondary response: Response provided within 30 seconds of an event, which can be sustained for a further 30 minutes.
  - High frequency response: Response provided within 10 seconds of an event, which can be sustained indefinitely.

Reserve Services

- Balancing Mechanism (BM) start-up: The BM start-up service gives NG on-the-day access to additional fast starting generation. The service is open to any BM participants who expect to be unavailable within BM timescales of 89 minutes. This service is divided as follows:
  - BM start up: This is the case in which a generating unit can be brought to a state where it is capable of synchronizing with the system within BM timescales.
  - Hot standby: This refers to the process of holding the generating unit in this state of readiness to produce energy. The unit will then either remain in hot standby until the end of its capability or be instructed to run via an offer in the BM.

  BM start up instructions are issued with information that specifies a hot standby target time. This is the time at which the unit must be ready to synchronize within BM timescales of 89 minutes

- Demand turn up (DTU): This service incentivizes large energy users and generators to either increase demand or reduce generation at times of high renewable output and low national demand. This typically occurs overnight and during weekend afternoons in the summer. The service is open to any technology that has the flexibility to increase demand or reduce generation during times of low demand and high renewable output, this includes: true demand turns up; combined heat and power (CHP); any other type of generation; energy storage (such as batteries); and other technologies, providing they can offer the flexibility required. The entry threshold for participation is 1 MW. This can be aggregated from sites 0.1 MW and larger. In 2016, the average length of delivery was 4 hours 20 minutes. In 2017, the average length of delivery was 3 hours 34 minutes. As with duration of delivery, the speed in which a provider needs to respond is linked to individual providers' capabilities.

- Fast reserve: Fast reserve provides rapid and reliable delivery of active power through increasing output from generation or reducing consumption from demand sources. NG uses fast reserve, in addition to other energy balancing services, to control frequency changes that might arise from sudden, and sometimes unpredictable, changes in generation or demand (e.g., VER variability and uncertainty). For active power delivery, providers must meet the following criteria:
  - Active power delivery must start within 2 minutes of the dispatch instruction;
  - A delivery rate in excess of 25 MW/minute;

- The reserve energy should be sustainable for a minimum of 15 minutes; and
- Must be able to deliver a minimum of 50 MW.

- Short term operating reserve (STOR): This resource is used to accommodate unforeseen events such as deviations from forecasts and generation contingencies. The service is open to any technology with the ability to increase generation or reduce demand by at least 3 MW (this could be aggregated from a given site). These resources must be able to sustain the response for a minimum of 2 hours. Providers should be able to respond to an instruction from NG within a maximum of 240 minutes, although response times within 20 minutes are preferable.
- Super Stable Export Limit (SEL): This resource is utilized to directly decrease the sum of the minimum MW level or SEL of generators synchronized to the system by lowering their minimum generating levels. Super SEL service does not require a change in energy output of the generation, it is to give access to a reduced minimum active power level. Super SEL contract enactment will be a through a trading instruction. Dispatch will be via the Balancing Mechanism to reduce output to the new lower SEL if required. Super SEL providers must deliver a minimum of 10 MW of footroom under a maximum notice period of 12 hours before SEL reduction.

Eskom

Eskom generates approximately 95% of the electricity used in South Africa and approximately 45% of the electricity used in Africa. Eskom generates, transmits and distributes electricity to industrial, mining, commercial, agricultural and residential customers and redistributors. Part of Eskom's responsibilities includes operating and maintaining system reliability. In order to do this, Eskom sets the amounts and processes to deliver various ancillary services including reserves. The reserves are divided into five categories, and the minimum requirements for each of the categories is revised on an annual basis, [47]. The reserve procured for each category is also exclusive, i.e., the amount of reserve scheduled for a given category cannot count to the contribution to any other category.

The reserves descriptions and technical requirements are described under the following headings.

Instantaneous Reserve

This is the generation capacity that is fully available within 10 seconds to arrest frequency excursions due to unforeseen events (e.g., generator contingencies) outside the frequency deadband. This reserve should be sustained for at least 10 minutes. The requirements for instantaneous reserves are determined via dynamic simulation studies to determine the effect of governor response on system frequency. These studies shall consider representative levels of generation, including variable energy sources (VER), and demand side capacity. The minimum requirements, which are assumed to be sourced by conventional generators are shown in Table 3-2.

Table 3-2
Instantaneous reserve requirements, Eskom, [47]

Season	Period	2017/18 MW	2018/19 MW	2019/20 MW	2020/21 MW	2021/22 MW
Summer/ Winter	Peak	500	500	500	500	500
	Off peak	800	800	800	800	800

Regulating Reserve

The regulating reserve is the generation capacity or demand side managed load that is available to respond with 10 seconds and is fully activated with 10 minutes. The purpose of this reserve is to maintain the frequency as close to reference as possible and to keep the tie line flows between control areas within the scheduled levels. The amounts of regulating reserve are based on two main requirements:

1. Load pick up and drop off capacity that the exceeds the average 10-minute demand (based on 4-seconds SCADA) for a given % period. To determine this, a load variation study is carried out. Such study considers the typical weekly load profiles in summer and winter.
2. Compliance with South African Power Pool (SAPP) CPS performance criterion requirement (ensures frequency is within dead band for 95% of the time).

Table 3-3
Regulating reserve requirements, Eskom, [47]

Season	Reg. up, MW	Reg. down, MW	Reg. up/down, MW
Winter (May-Aug)	600	400	500
Summer (rest of year)	500	400	450

Ten-Minute Reserve

The ten-minute reserve is the generating capacity or demand side managed load that can respond within 10 minutes when called upon. It could include off line generation that has the ability to synchronize and produce within the 10 minutes. This reserve is used to restore the amounts of instantaneous and regulating reserves to their required levels after an incident occurs. In terms of requirements, this reserve is set to withstand the outage of three coal fired units ($3 \times 722 = 2166$ MW), or to observe the SAPP requirements, which require a minimum of 1037 MW.

The ten-minute reserve requirements are calculated as:

Ten-minute reserve = Total operating reserve – Instantaneous reserve – Regulating reserve

Table 3-4
Ten-minute reserve requirements, Eskom, [47]

Period	2017/18 MW	2018/19 MW	2019/20 MW	2020/21 MW	2021/22 MW
Summer peak	1050	1250	1150	1150	1150
Summer off-peak	750	950	850	850	850
Winter peak	1000	1200	1100	1100	1100
Winter off-peak	700	900	800	800	800

Supplemental Reserve

Supplemental reserve is the generating capacity or demand side load that can respond in 6 hours or less to restore operating reserves. This reserve must be available for at least 2 hours. The amount of supplemental reserve is optimized taking into account the suppliers cost, to meet a determined amount at a minimum cost, Table 3-5.

Table 3-5
Supplemental Reserve requirements, Eskom, [47]

Period	2017/18 MW	2018/19 MW	2019/20 MW	2020/21 MW	2021/22 MW
Peak/off peak	1300	1300	1300	1300	1300

Emergency Reserve

Emergency reserve should be available within 10 minutes. These reserves are used in accordance to some specific procedures to respond to emergency situations. The sources include interruptible loads, generator emergency capacity, and gas turbine capacities. This reserve must be under direct control of the National Control. The requirements of this reserve are to be equal to the worst contingency in the system, which is equal to the loss of the largest power station. This contingency must be met by operating, supplemental and emergency reserves. The requirements are shown in Table 3-6.

Table 3-6
Emergency reserve requirements, Eskom, [47]

Period	2017/18 MW	2018/19 MW	2019/20 MW	2021/21 MW	2021/22 MW
Peak/off peak	500	300	900	900	900

4
SUMMARY

Due to the increasing penetration levels of variable energy sources (VER) in power systems across the world, an increasing number of balancing areas have found the value to modifying the system's reserve requirements of both existing reserve products as well as the introduction of new products. These adjustments would allow an efficient integration of the VER while maintaining or in some cases increasing the system reliability, importantly factoring in the notion that variability and uncertainty impacts are not constant across all times and system conditions. Additionally, several system operators have complemented (or are exploring the possibility) their reserve procurement with additional services such as ramping services, those which are separate from traditional contingency reserve. These additional services would ensure that the system pre-positions its available generating resources to follow the net demand dynamics considering the desired look-ahead intervals. Others system operators are even considering other complementary products that not only allow a more efficient integration of VER, but the participation of other emerging technologies such as storage, under different time frames where existing products did not quite fit (e.g., fast frequency response).

Table 4-1summarizes some of the take away points of this survey.

Table 4-1
Reserve and flexibility tools available for system operation

SPP	MISO	NYISO	ISO-NE	ERCOT	Duke Energy	Elia	NG (UK)	ESKOM
Reserves: Quasi-static as a function of load and wind magnitude and variability. Exploring the possibility of integrating a ramping product. As of 2016, 60% of the wind generation was dispatchable.	Regulating reserves determined on an hourly basis based on experience. Contingency reserve is fixed. Short-term capacity reserve to mitigate uplift payments and out of market corrections. Explicit ramp product available since May 2016.	Reserves based on static criteria. Considering implementing an explicit ramping product.	Regulation reserves varies by hour. Others static and adjusted at SO discretion. Ramps: Ad hoc dispatch or reserve adjustments. Ongoing discussion on ramping capabilities and other alternatives.	Time dependent reserve products based on historical data. Also considers ramping risk in non-spinning reserves. Considered a new redesign of their ancillary services, NPRR863.	Integrate VER variability into reserve requirements determination. Include longer look-ahead horizons as well as weather data.	Reserve based on static methods. Exploring new methods to explicitly dimension reserve requirements to maintain a desired (or lower) level of risk at a minimum cost.	Different amounts of A/S by time-dependent windows of need. Enhanced Frequency Response (1 sec). Fast reserve at a rate of 25MW/min within 2 min and for at least 15 min. Super SEL product to guarantee a desired level of aggregated minimum generation.	Seasonal adjustments based on system conditions. Implicit ramping in dispatch and reserve procurement.

Some general remarks on the products explored are given below. These remarks are made in a generic way, and the actual application and value of the products found would be completely system dependent. However, they follow some broad principles, which are pointed out below:

- **Reserve requirements**: As pointed out in a few of the works surveyed, the actual reserve needs vary as a function of system conditions. Setting the needs based on static criteria, could result in excessive procurement during some periods, or scarce provision during others. A solution to this issue would be to quantify the actual needs for the different reserve types as the system conditions change and enforce these requirements. This would result in equal or even enhanced system reliability and lower operating cost.
- **Ramp procurement**: Neglecting the need to enforce explicit ramping requirements could result in scarce reserve procurement over different time horizons. On the other hand, explicitly acknowledging the need of catering sufficient ramping capability in the system, would allow agile and unrestricted transition between different operating points in time, for different levels of net demand variability and uncertainty. Note as well that the ramping capability is complementary to other products, and might aid in reducing the need for explicit ramps (e.g. dispatchability of VER).
- **Fast frequency response**: Emerging technologies feature different response rates than those of conventional generating units. As a consequence, these technologies are able to respond and relieve other resources in providing fast services. This generates a natural complementarity among resources.
- **Maximum aggregated footroom**: Systems that are undergoing deep penetrations variable energy sources (VER), might need to enforce a minimum amount of conventional generation to remain synchronized in the system at periods in which the VER production is high. This is to ensure that there would be sufficient resources to maintain the balance when the VER production decreases. As the penetrations of VER increase, this need to enforce equivalent product will become more evident.
- **Complementary reserve products**: Each SO has its own array of reserves and flexibility products to respond to predicted as well as unforeseen events in their system. However, in some cases these tools might be insufficient to meet their evolving needs either in terms of reliability or market constructs. Therefore, the creation of complementary products could aid in increasing system flexibility to attain a desired level of reliability as well as to avoid resorting to more expensive corrective actions in real-time and out-of-market amendments.

5
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3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com