

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Essential Reliability Services Task Force Measures Framework Report

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RELIABILITY | ACCOUNTABILITY



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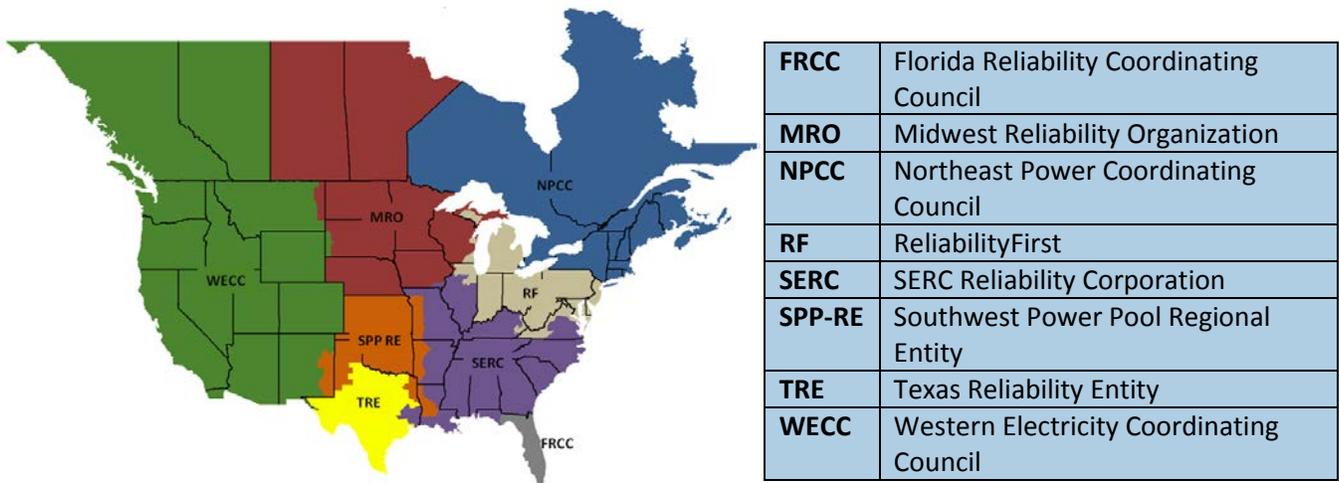
Table of Contents

Executive Summary	
Summary Table of Measures and Recommendations.....	iii
Frequency Support	1
Net Demand Ramping Variability	5
Voltage Support.....	8
Policy and Advisory.....	9
Appendices	10
A. Frequency Support.....	Error! Bookmark not defined.
B. Net Demand Ramping Variability.....	20
C. Reactive Power and Voltage Control.....	34

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



Disclaimer: This is a working document for the Essential Reliability Services Task Force (ERSTF) and is not final. References to entities and their responsibilities does not establish or modify requirements or obligations under NERC’s Reliability Standards. Further, due to the preliminary nature of the data and information provided within this working document, such data is subject to revision and should not be construed as conclusive or otherwise relied upon as it and the overall content of the working document may change as the ERSTF efforts continue and feedback is provided by NERC staff, NERC standing committees, and industry.

Executive Summary

The North American BPS is undergoing a significant change in the mix of generation resources and the subsequent transmission expansion. Driven by a combination of factors, the rate of change in certain regions is having a tremendous impact on planning and operating the BPS. For example, environmental regulations are contributing to substantial retirement of conventional coal-fired generation while renewable portfolio standards and other factors are driving the development of variable energy resources (VERs). This has resulted in new generation being primarily natural gas fired and an increase in the penetration of wind and solar resources. At the same time, load participation is increasing through demand response and distributed generation. These changes in the generation resource mix and technologies are altering the operational characteristics of the grid and will challenge system operators in maintaining reliability, thereby raising issues that need to be further examined. More specifically:

- **Impact of Retirements:** Conventional units, such as coal plants, inherently provide voltage and frequency support services as a function of their large spinning generators and control settings. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available.
- **Replacement Resources:** Gas-fired units and VERs can be equipped to provide similar reliability services; however, the functionality could potentially not be installed or made available due to cost or market rules. As the generation resource mix evolves, the reliability of the electric grid depends on the operating characteristics of the replacement resources.
- **Resource Capability:** Merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the electric grid to have resources with the capability to sufficiently provide these services and maintain system balance.

Creation of the ERSTF

The NERC Planning Committee and Operating Committee jointly created the Essential Reliability Services Task Force (ERSTF) in 2014 to consider the issues that may result from the changing generation resource mix; the committees and the ERSTF released an ERSTF concept paper in October 2014. The committees agreed that it was prudent to identify the essential reliability services, monitor the availability of these services, and develop measures to ensure the industry has sufficient awareness of the change in reliability services in the future. As noted in the concept paper, the key characteristics of a reliable grid can be categorized into two main categories: 1) voltage support, and 2) frequency support. The changing generation mix raises a number of potential concerns, and the ERSTF has been asked to identify measures that should be monitored to ensure reliable operation of the BPS.

Objectives of the ERSTF

The purpose of the ERSTF is to develop potential measures and utilize data from across North America to assess the validity of these measures and to provide insight into trends and impacts of the changing resource mix. The analysis conducted by the ERSTF is focused on potential measures that may be monitored by NERC, the appropriate NERC registered entities (such as Balancing Authorities (BAs)), and the industry to identify potential reliability concerns that may result from the changing resource mix. These measures are intended to provide the appropriate NERC registered entities and the industry with both a short-term operational view and a long-term planning horizon view that should allow them to identify immediate reliability concerns and look into the future for needed adjustments. The ERSTF established three technical sub-teams focusing on 1) frequency support, 2) ramping capability, and 3) voltage support. While ramping is often viewed as an aspect of frequency support, timing differences tend to suggest different measures, and they should be reviewed as separate (but related) topics. The ERSTF also created a fourth sub-team to develop materials, such as this report, to communicate and inform industry, policy makers, and regulators.

Purpose of this Report

The purpose of this report is to explore important directional measures to help the industry understand and prepare for the increased deployment of VERs, retirement of conventional coal units, and other changes to the traditional characteristics of generation and load resources. The ERSTF is not asserting that it has developed the final answer to this complex transformation; rather, the group is presenting concepts and proposing potential measures based on discussions with system operators and researchers studying these issues. The ERSTF had discussions with CAISO, ERCOT, IESO, and others experiencing significant transitions in generation resource mix or involved in policy matters relating to these changes. Based on these discussions and other sources of information, the ERSTF has concluded that the generation resource mix does not solely impact the generation system in isolation. These changes can and do have a profound impact on the transmission and distribution infrastructure, and these impacts cannot be ignored in energy policy making, system planning, or system operating efforts.

Summary of Recommendations

The recommended measures are described in more detail in the body of the paper and can be summarized as follows:

- Frequency Support Measures
 - Each interconnection and each BA should calculate the following measures (Measures 1, 2, and 3):
 - Measures 1 and 3 calculate the instance of minimal synchronous inertial response (SIR) that occurred in the recent historical study year and its projected value for the next three years (Measure 1 for interconnection and Measure 3 for BAs).
 - At a minimum, for SIR conditions for each of the historical and future years above, determine the frequency deviation that would result within the first 0.5 seconds following the largest contingency of the interconnection (Measure 2).
 - The ERSTF continues to study two additional possible measures related to the interconnection's minimum frequency point (the "Nadir") following the largest contingency during minimum SIR conditions (Measure 4) and situational awareness modeling of available inertia for near-real-time applications when operating the grid (Measure 5). Additional measures for frequency response are not needed at this time. NERC Reliability Standard BAL-003-1 will be implemented in April 2015, and the calculations, reporting requirements, and guidelines associated with this standard will provide suitable measures for frequency control and response performance.
- Net Demand Ramping Variability Measures
 - Each BA should calculate the historical and projected maximum one hour up, one hour down, three hour up, and three hour down net load ramps (actual load less production from VERs) using one-minute data (Measure 6).
- Voltage Support Measures
 - Measures of reactive capability should be calculated and tracked by the appropriate registered entity, including both static and dynamic reserve capability per total megawatt load at peak, shoulder, and light load levels; and load power factor for distribution at the low side of transmission buses at peak, shoulder, and light load levels (Measure 7).
 - Measures of voltage performance should include tracking voltage exceedances during real-time operations and monitoring buses with low short-circuit strength or susceptibility to fault-induced delayed voltage recovery (FIDVR) conditions (Measure 8).

- Periodically review system events that stress reactive capability or degrade voltage profiles to compare planned performance with real-time operations and evaluate voltage performance (Measure 9).

This report identifies potential measures (listed in Table 1) that illustrate the concerns with regard to the change in generation mix. While the ERSTF believes that the measures are useful benchmarks for the future, additional measures should be investigated and monitored. To verify that these measures are identifying the challenges with the changing generation mix, the ERSTF will request that entities provide data or analytical results. Therefore, in the next phase of this project, additional reliability coordinators (RCs), BAs, transmission operators (TOPs), and planning coordinators (PCs) will be requested to conduct similar assessments and provide the ERSTF with their results. Alternatively, organizations can provide the data to the ERSTF for evaluation.

Upon review of these new studies, the ERSTF will combine and compile the results into a more complete set of recommendations for the industry to consider, including documentation that can be shared with policy and regulatory agencies. The ERSTF plans to issue its final recommendations by December 31, 2015.

Summary Table of Measures and Recommendations

Table 1: Summary Table of Measures and Recommendations

Measure Reference Number	Measure Title	Brief Description	ERSTF Status of Recommendation	Planning Committee Recommendation	Operating Committee Recommendation
1	Synchronous Inertial Response at an Interconnection Level	Measure of Kinetic Energy at the interconnection level. It provides both a historical and future (3 years out) view.	Recommended to PC/OC	Endorsed Dec. 2014	Endorsed Dec. 2014
2	Initial Frequency Deviation Following Largest Contingency	At minimum SIR conditions from Measure 1, determine the frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the Resource Contingency Criteria (RCC) in BAL-003-1 for each interconnection).	Recommended to PC/OC	Endorsed Dec. 2014	Endorsed Dec. 2014
3	Synchronous Inertial Response at a BA Level	Measure 3 is exactly the same as Measure 1 but performed at the BA level. It provides both a historical and future (3 years out) view and will help a BA to identify SIR-related issues as its generation mix changes.	Recommended to PC/OC	Endorsed Dec. 2014	Endorsed Dec. 2014
4	Nadir at Minimum SIR Conditions	Frequency nadir following the largest contingency during minimum SIR conditions. This measure would be performed at the interconnection level.	Under Review		
5	Real Time Inertial Model	Develop a real-time model of inertia, including voltage stability limits and transmission overloads as criteria. This is an operator tool for situational awareness and alerts them if the system is nearing a limit and any corrective action is required.	Under Review		
6	Net Demand Ramping Variability	Measure of net demand ramping variability at the BA level. It provides both a historical and future view.	Recommended to PC/OC	Endorsed Dec. 2014	Endorsed Dec. 2014
7	Reactive Capability on the System	At critical load levels, measure static & dynamic reactive capability per total MW on the transmission system and track load power factor for	Under Review		

Summary Table of Measures and Recommendations

		distribution at low side of transmission busses.			
8	Voltage Performance of the System	Measure to track the number of voltage exceedances that were incurred in real-time operations. This should include both pre-contingency exceedances and post-contingency exceedances. Planners should consider ways to identify critical FIDVR buses and buses with low short-circuit levels.	Under Review		
9	Overall System Reactive Performance	Based on reactive capability and voltage performance, measure to determine if the overall system strength poses a reliability risk. Adequate reactive margin and voltage performance would be evaluated in all operating horizon studies (seasonal, daily, etc.) and in state-estimated real-time contingency analysis.	Under Review		

Frequency Support

Frequency support is the response of generators and loads to maintain the system frequency in the event of a contingency. For the ERSTF's purposes, the frequency support response generally consists of a combination of very fast inertial response, fast frequency response, primary frequency response, and some slow responses to supplement the resources that have responded more quickly.

The inertial response is the fastest response obtained from the kinetic energy in the spinning mass of large synchronous generator units. In order to measure and identify trends in the SIR level with changing generation mix in a system, an inertial response measure is needed at the interconnection level to show how the interconnections are performing. A second measure is needed at the BA level to identify changes in contribution toward an interconnection's SIR.

Interconnections with growing amounts of non-synchronous generation or electrically coupled resources should project future SIR trends based on historical SIR information and planned projects in the interconnection queue (e.g., signed interconnection agreements and financial commitments). These projections will help BAs anticipate decreasing interconnection SIR conditions, which will increase the challenges associated with meeting the interconnection frequency response obligations (IFROs) to preserve reliability.¹ The ability to anticipate the changes in SIR will help BAs develop measures to offset any decline in SIR to meet their IFRO as required in BAL-003. During the planning of the BPS, understanding how changes in SIR interact with primary frequency response will be crucial to preserve reliability and determine if a minimum SIR requirement is necessary.

Measure 1: Synchronous Inertial Response at an Interconnection Level

This is a measure of kinetic energy at the interconnection level. It provides both a historical and future (three years out) view.

1. For every hour in a year, determine the total available inertial response from all online synchronous generators in the interconnection. Identify the instances and conditions that resulted in the minimum inertial response in a year. If an hourly sampling of inertial data for an entire year is not available, then use several historical snapshots that have yielded low system inertia conditions.
2. Project the minimum inertial response in future years (the next three years).

Measure 2: Initial Frequency Deviation Following Largest Contingency

This measure is extrapolated from Measure 1 and applies at the interconnection level.

1. At minimum SIR conditions from Measure 1 for each year, determine the frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the resource contingency criteria (RCC) in BAL-003-1) for each interconnection. The half-second window is sufficient to show the general frequency trend. This initial frequency deviation is not affected by other responses, such as primary frequency response, and therefore illustrates only the effect of system inertia on system frequency deviation.
2. At minimum SIR projections from Measure 1 for a future year, determine the projected frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the RCC in BAL-003-1) for each interconnection.

¹ http://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/BAL-003-1_clean_031213.pdf

Data Requirements for Interconnection Level Measures 1 and 2

- Historical: generator on-line/off-line status, inertia constant (H) for every synchronous generator, MVA rating for every synchronous generator in the interconnection.
- Future: anticipated non-synchronous generation in a future year, based on planned projects with signed interconnection agreements in each BA area of an interconnection.

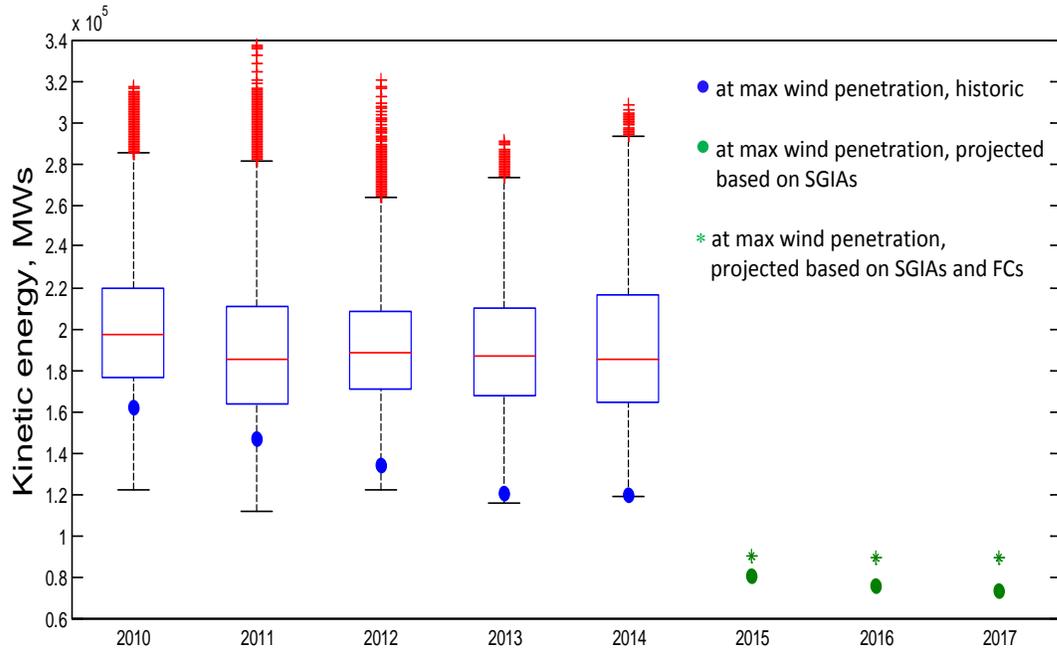


Figure 1: ERCOT Historic Kinetic Energy Boxplots (2010–2017)

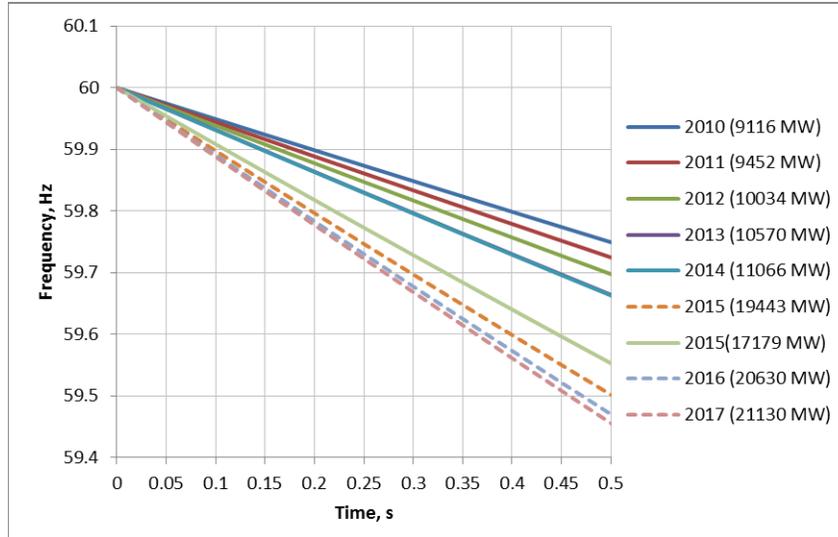


Figure 2: Calculated ERCOT System Frequency after 2750 MW Generation Trip (2010-2017)

Measure 3: Synchronous Inertial Response at a BA Level

This measure is exactly the same as Measure 1 but is taken at the BA level instead. It provides both a historical and future (three years out) view and will help BAs identify SIR-related issues as their generation mixes change.

1. For every hour in a year, determine the total available inertial response (kinetic energy) from all online synchronous generators in the BA. Identify the instances and conditions that resulted in the minimum inertial response in a year. If an hourly sampling of inertial data for an entire year is not available, then use several historical snapshots that have yielded low system inertia conditions.
2. Project minimum inertial response in a future year (the next three years) as shown in Figure 1.

Data Requirements for BA Level Measure 3:

1. Historical: generator on-line/off-line status, inertia constant (H) for every synchronous generator, MVA rating for every synchronous generator in the BA.
2. Future: anticipated non-synchronous generation in a future year based on planned projects with signed interconnection agreements in each BA area of an interconnection.

The detailed calculation procedure for the proposed measures (Measures 1-3) is provided in the appendix, titled “Frequency Response.”

Additional Measures under Consideration

The ERSTF has identified two additional measures for further analysis. More studies are planned to further analyze these measures.

Measure 4

Identify the frequency nadir trend of the interconnection following the largest contingency during minimum SIR conditions.

Measure 5

Develop a real-time model of inertia including voltage stability limits and transmission overloads as criteria. This is an operator tool for situational awareness and alerts them if the system is nearing a limit. It includes any corrective action that is required.

Frequency Response (Primary Frequency Control)

In order to measure frequency response performance, a metric is needed at the interconnection level to show how the individual interconnections are performing, and a second metric is needed at the BA level to measure BA frequency response performance. The BAs will need to measure the performance of individual resources to identify issues that are affecting their BA area. However, the ERSTF believes that approved standards provide sufficient measures of frequency response and there is not a need to define additional measures. Specifically:

- **Interconnection Level** – ALR1-12 is a metric used to track and monitor interconnection frequency response. Frequency response is a measure of an interconnection’s ability to stabilize frequency immediately following the sudden loss of generation or load. It is defined as the sum of the change in demand and the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 hertz (MW/0.1 Hz). ALR1-12 frequency event detection methodologies are being refined to make them more meaningful and aligned with the implementation of NERC Reliability Standard BAL-003-1.
- **BA Level** – BAL-003-1 has been approved by FERC and is awaiting implementation in April 2015. BAs started collecting data in December 2014, and the first reporting period to NERC will be January 2016, when BAs will provide appropriate forms in support of bias calculations for 2016. The first metric report will potentially be available in January 2018.
- **Resource Level** – The individual resource level is too granular to measure for interconnection-level purposes. However, resource performance may be measured at the BA level as needed by individual BAs to manage their frequency response performance under BAL-003-1. The first recommendation of the NERC Frequency Response Initiative Report (FRI Report) states, “NERC should embark immediately on the development of a NERC Frequency Response Resource Guideline to define the performance characteristics expected of those resources for supporting reliability.”² The recommendation goes on to describe the parameters of the recommended guideline. NERC staff has been developing a Reliability Guideline to identify the characteristics of frequency response and resource performance. They will be seeking input from and concurrence with the NERC Resources Subcommittee (RS) and approval by the NERC Operating Committee.

²http://www.nerc.com/pa/Stand/Frequency%20Response%20Project%20200712%20Related%20Files%20DL/FRI_Report_091112_Draft.pdf

Net Demand Ramping Variability

Changes in net demand require BAs to call on generators, loads, or other system load following capabilities. BAs with high penetrations of wind, solar, and non-dispatchable resources may need faster system ramping capability to follow changes in net demand. For example, Figure 3 shows the actual wind (green curve) and solar (yellow curve) production variability experienced by California Independent System Operation (CAISO) on March 1, 2014, and Figure 4 shows the actual load (blue curve) and net load (red curve) for the same day. As shown, the multi-hour ramp during the evening hours partly coincides with sunset. In addition to meeting the increase in load, CAISO must ensure that enough system ramping capability is available to follow the changes in solar and wind production. As BAs integrate more VERs into their resource mixes, the need for system ramping capability may increase to ensure compliance with real-time control performance standards.

This may not be a challenge for some BAs, but those with a significant amount of non-dispatchable generation or base-loaded generation may not be able to commit more dispatchable resources due to the risk of over-generation on low demand days, such as on weekends or holidays.

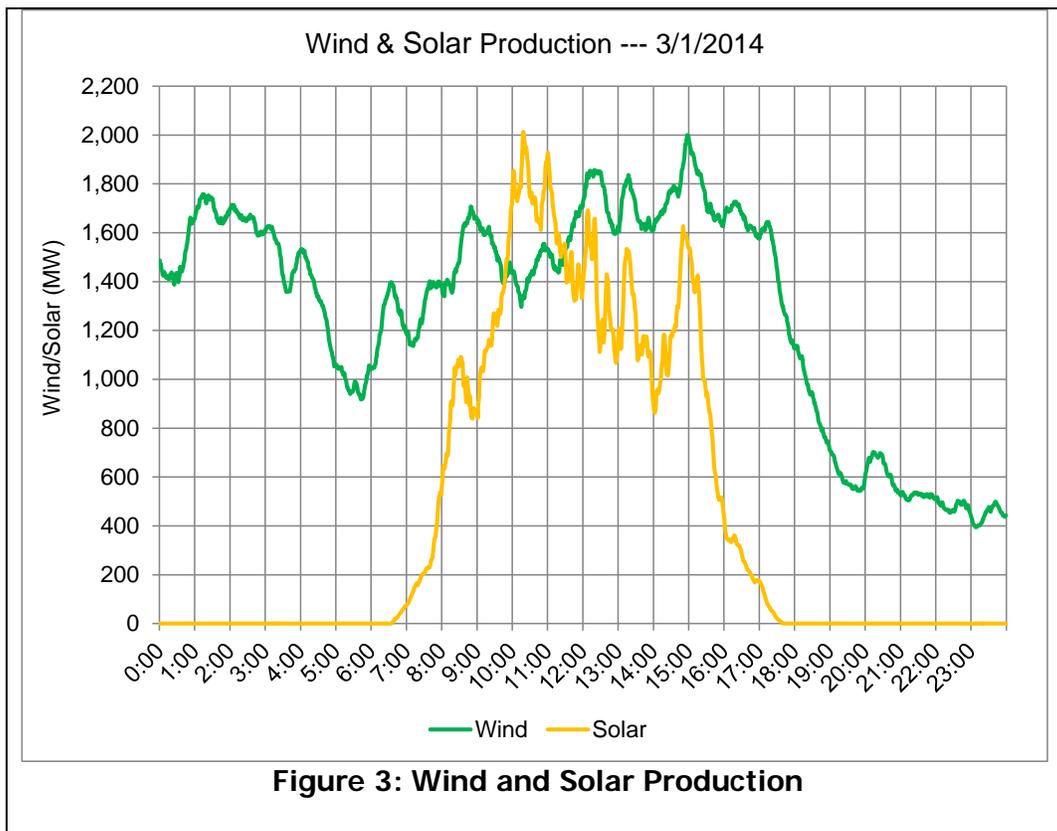


Figure 3: Wind and Solar Production

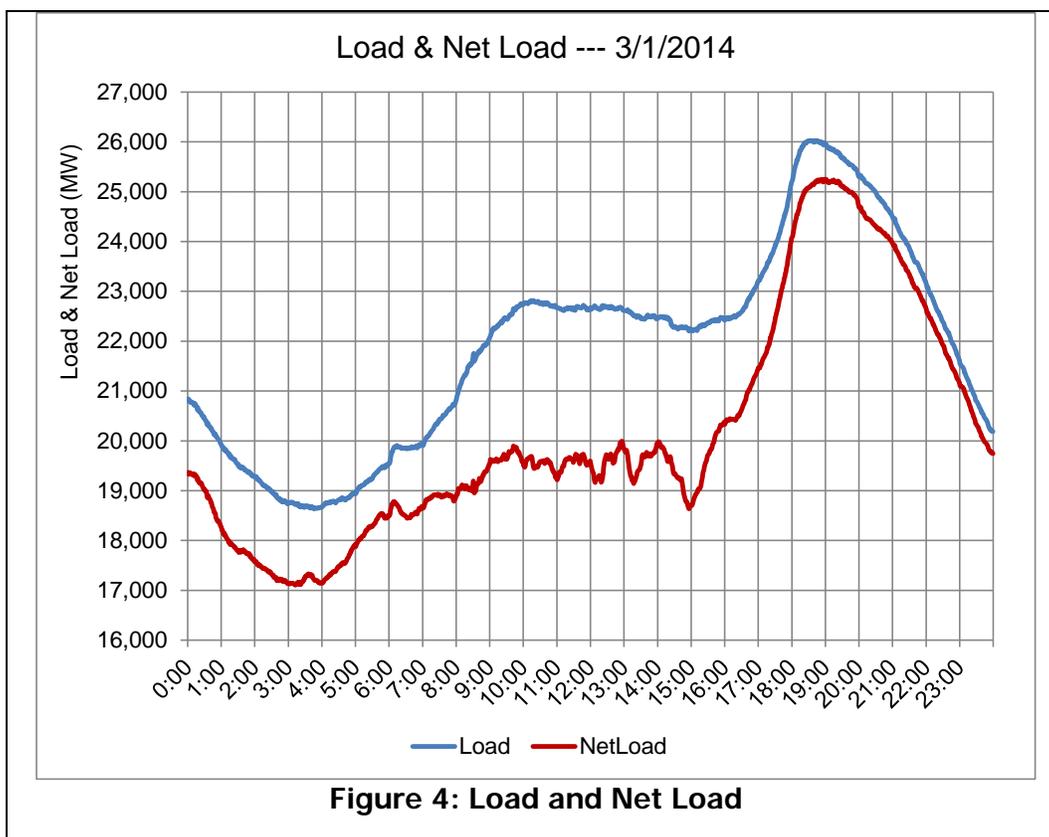


Figure 4: Load and Net Load

Measure 6: Net Demand Ramping Variability

This is a measure of net demand ramping variability at the BA level. It provides both a historical and future view of the maximum one hour up, one hour down, three hour up and three hour down net variability. The net variability generally means the difference between total load and production from VERs, although other variable loads and generation types may be included. It is recommended that this analysis be done for the current study year, three recent historical years, and a projected year four years in the future (e.g., the 2014 study year would include 2011–2013 historical years and the 2018 future year).

Data Requirements

Calculating the net demand ramping variability measure will generally require one-minute data (or the smallest sample rate available, such as five-minute data) and the creation of a projected build-out of generation and load. One recommended approach is for BAs to use the most current full year of actual load data in one-minute increments and the most current load forecast available from their energy commissions or other forecasts that they rely on for system planning studies. Using one-minute load profile data together with one-minute wind and solar production profiles, BAs can develop minute-by-minute net load profiles by subtracting the wind and solar profiles from the load profiles. BAs can then use this data to identify the maximum one hour up, one hour down, three hour up and three hour down net variability.

Discussion and Considerations

The spinning reserve portion of a BA's contingency reserve requirement may or may not be included in the one-hour or three-hour flexible capacity needs determination. Some BAs may decide to include the spinning reserve portion because contingencies do occasionally occur during an up ramp. Another reason for including spinning reserve is because many of the same resources that provide contingency reserves may also be supplying ramping needs.

The appendix titled “Net Demand Ramping Variability” describes the data, approaches, and details for building the future VER portfolio, including the build-out of load, wind, and solar profile, as well as defining the BA’s ramping needs. Examples are provided to show how this is currently being done for both ERCOT and CAISO.

Voltage Support

The ability to control the production and absorption of reactive power for the purposes of maintaining desired voltages is critical to the reliable and efficient operation of the power system. Unlike frequency response, which primarily pertains to large regions, voltage issues can be local. To assess the strength of the system, and to some degree the overall reliability of the system, the industry should consider tracking several measures related to voltage support. The measures can be used to assess the strength of reactive support and to quantify trends that may result from the changing resource mix of both generation and load.

Regional differences may require some flexibility or customization of the Measures. Systems vary widely in their topology and electrical characteristics (e.g., the total level of installed reactive resources, the type of generation resources, applicable local and regional voltage criteria, etc.). In general, measures may align with the BA construct under the NERC functional model, but because of the localized nature of reactive capability, more useful insights may be gained by monitoring the measures for appropriate areas under a BA.

Measures under Consideration

The ERSTF has identified three measures for further analysis. The measures are listed below and for more completeness and details about these measures, please refer to Appendix C. More studies are planned to further analyze these measures.

Measure 7: Reactive Capability on the System

This measure tracks the rotating and non-rotating dynamic reactive capability per total megawatt load on the system for various areas at critical load levels (i.e., peak, shoulder, and light load).

Measure 8: Voltage Performance of the System

This measure tracks the number of voltage limit exceedances occurring in real-time operations, based on established BA-level voltage criteria.

Measure 9: Overall System Performance

This measure determines a system's reactive capability and voltage performance to identify if the overall system strength poses a reliability risk. In addition, this measure proposes evaluation of adequate reactive margins and voltage performance for operational and planning horizon studies.

Policy and Advisory

The key message to communicate to the industry and policy decision makers is that the BPS is changing, specifically as related to the characteristics of generation assets. The BPS is a complex network, and significant changes to it can have widespread effect across the continent. The changes that have been occurring affect both operational and planning paradigms that have been in place for decades and have been exemplified by the experiences of CAISO, ERCOT, and international groups (e.g., the operational challenges of large amounts of photovoltaic resources deployed in Germany). Industry needs to understand the operational impacts of the changes, not only to prepare system planners and operators to effectively manage any risks to reliability, but also to inform policy makers and regulators of the issues so they are educated when making decisions.

Federal, state, and local jurisdictional policy decisions have a direct influence on changes in the resource mix, and thus can also affect the reliability of the BPS. Therefore, careful consideration needs to be given to the potential unintended consequences of policy decisions. Planning and operations to ensure reliability must be done in parallel with emerging changes to the BPS, all of which must be done with the acknowledgment of costs and potential consequences. Meeting these changes will require the planning of systems to ensure that system operators have the flexibility to modify the dispatch of units to meet real-time system reliability needs under a myriad of contingencies. Policies that limit system operator flexibility may impact the reliability of the BPS.

The measures developed and recommended by the NERC ERSTF provide insights into the current challenges in certain areas of North America as related to the changing generation resource mix. In addition, the measures will provide means of assessing future trends and engineering solutions to ensure that reliability is not degraded as the resource mix continues to evolve across all of North America. As such, the NERC ERSTF recommendations will assist in informing policy makers of the implications of the changing resource mix and how industry can evolve the system in a reliable manner.

Appendix A – Frequency Support

Inertial Response

Synchronized rotating turbine generators and motors that are interconnected to the system contain kinetic energy in the form of inertia. Inertia provides an important contribution in the initial moments following a generation or load trip event that impacts frequency by reducing the rate of change of frequency decline. In response to a sudden loss of generation, energy will automatically be extracted from the rotating synchronized machines on the interconnection as frequency declines and the machines slow down. The amount of inertia depends on the number and size of generators and motors synchronized to the system, and it determines the rate of frequency decline. Greater inertia reduces the rate of change of frequency, giving more time for primary frequency response to fully deploy and arrest frequency decay above under-frequency load shed set points.

With the increasing use of non-synchronous generation, other electronically coupled resources, and changing load characteristics, synchronous inertial response (SIR) is reduced. Particularly in areas with a high share of renewable resources, this leads to a need to determine minimum amounts of SIR necessary to ensure system reliability as well as the required amounts of primary frequency response based on expected SIR conditions. For systems where the amount of SIR is decreasing, various ways of compensating to maintain reliability are possible, potentially including synthetic inertia from wind turbines (very fast frequency response) and synchronous condensers. In some cases, retiring coal plants could be converted to synchronous condensers that provide inertia and other services without emissions.

Frequency Response (Primary Frequency Control)

Frequency response can be divided into three categories that are applicable to certain operating periods of time:

- Primary frequency control (immediate time frame)
- Secondary frequency control (seconds to minutes)
- Tertiary frequency control (tens of minutes and longer)

Primary frequency control, also known as frequency response, comes from automatic generator governor response, load response, and other devices based on local (device-level) frequency-sensing control systems. In general, frequency response refers to the initial actions provided by the autonomous devices within an interconnection to arrest and stabilize frequency deviations, typically from the unexpected sudden loss of a generator or load.

Primary frequency control is quick and automatic; it is not driven by any centralized control system, and it begins seconds after a system frequency event. Response to a frequency event can be provided by various sources, including generation resources, loads, and storage devices. Each resource type may have different response times, and the level of positive contribution can vary depending on system conditions. Secondary and tertiary control are the centralized, coordinated control of generation, demand response, and storage resources, and these controls are performed by the system operator's energy management system over minutes to hours to balance generation and load.

Synchronized turbine generator automatic control systems (governors) can sense the decline in frequency and control the generator to increase the amount of energy injected into the interconnection. Frequency will continue to decline until the amount of energy is rebalanced³ through the automatic control actions of primary frequency

³ Offsets the amount of energy lost and replaces the amount of kinetic energy supplied by inertia.

response resources. Greater inertia reduces the rate of change of frequency, giving more time for governors to respond. Conversely, lower inertia increases the reliability value of faster-acting primary frequency control resources in reducing the severity of frequency excursions.

Procedure for calculation of historical and projected system SIR and rate of change of frequency (RoCoF)

The aim of this procedure is to:

- Analyze the impact from increasing amounts of non-synchronous generation on kinetic energy (synchronous inertia) trends of a BA or an interconnection over a number of years (at BA or interconnection levels).
- Find and analyze hours with lowest system inertia (at BA level or interconnection level).
- Calculate RoCoF after the largest contingency in those hours (only at an interconnection level).
- Project lowest system inertia conditions (highest RoCoF) for future years, based on non-synchronous generation projections.

1. Historic kinetic energy calculations and trends for future projections for Measure 1 (SIR at an interconnection level) and Measure 3 (SIR at a BA level)

1.1 Data requirements (from BAs in an interconnection)

- Power production by generator, i , for all synchronous generators in a studied system with hourly resolution, $P_i(t)$, for a historic year
- Hourly status (on-line/off-line) of synchronous condensers, if present in a studied system
- Total non-synchronous generation (NSG) in a studied system with hourly resolution, $P_{NSG}(t)$, for a historic year
- Hourly system load (including any HVDC exports/imports) for a historic year $P_{load}(t)$. (Note: In areas with significant HVDC imports, these can be included explicitly as non-synchronous generation $P_{NSG}(t)$.)
- MVA rating of each synchronous generator i in a studied system, MVA_i
- Inertia constant H_i for each generator and synchronous condenser i in a studied system (in seconds on machine MVA rating, MVA_i)
- If the inertia constant is not available, typical values based on generation technology may be used as a starting point (e.g., P. Kundur, “Power Systems Stability and Control,” p. 134 table with typical inertia constants).

1.2 Additional data requirements (at interconnection level)

- Largest contingency for a studied interconnection (as per NERC BAL-003), ΔP_{MW}
- Load damping, D , expressed in percent per 1 percent frequency change if available (if not available, a 0 load damping assumption represents a more conservative approach). Load damping data can be obtained from the analysis of past generation trip events.

1.3 Calculation procedure:

1. Calculate $H_i * MVA_i$ for each generator i .
2. For every hour t in a studied historical year, add $H_i * MVA_i$ of all generators that are on-line producing more than certain threshold (e.g., > 5 MW) and all synchronous condensers that are on-line:

$$KE(t) = \text{sum}(H_i * MVA_i) \tag{1}$$

3. Once kinetic energy is calculated for every hour, construct a boxplot for a studied year (e.g., with boxplot function available in Matlab), Figure A.1.
4. On the boxplot (Figure A.1) each box represents one year of historic kinetic energy data. On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, the whiskers correspond to +/- 2.7 sigma (i.e., represent 99.3% coverage, assuming the data are normally distributed), and the outliers are plotted individually (red crosses). If necessary, the whiskers can be adjusted to show a different coverage.
5. On the same figure, plot system inertia corresponding to NSG penetration peak in a year (blue dots in Figure A.1, which demonstrate downward trend for ERCOT).
6. Determine minimum kinetic energy in a year $KE_{min} = \min(KE(t))$. Does minimum kinetic energy in a year coincide with NSG penetration peak? These findings can be used for projections of minimum kinetic energy in a future year.

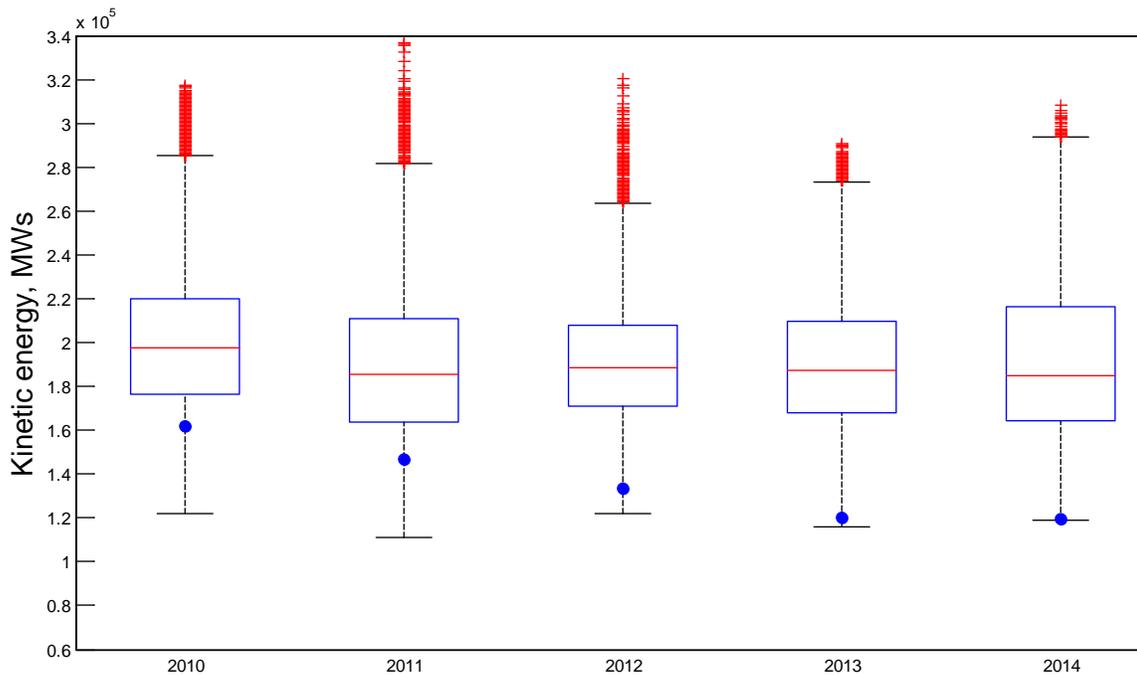


Figure A.1: Boxplot of Historic Kinetic Energy or Synchronous Inertia (2010-2014)

7. Calculate system net load as $PNL(t) = Pload(t) - PNSG(t)$ for every hour t in a year.
8. Plot hourly system inertia $KE(t)$ vs corresponding net load $PNL(t)$, and produce a trend line (e.g., linear trend line as $KE(t) = a \cdot PNL(t) + b$), Figure A.2.

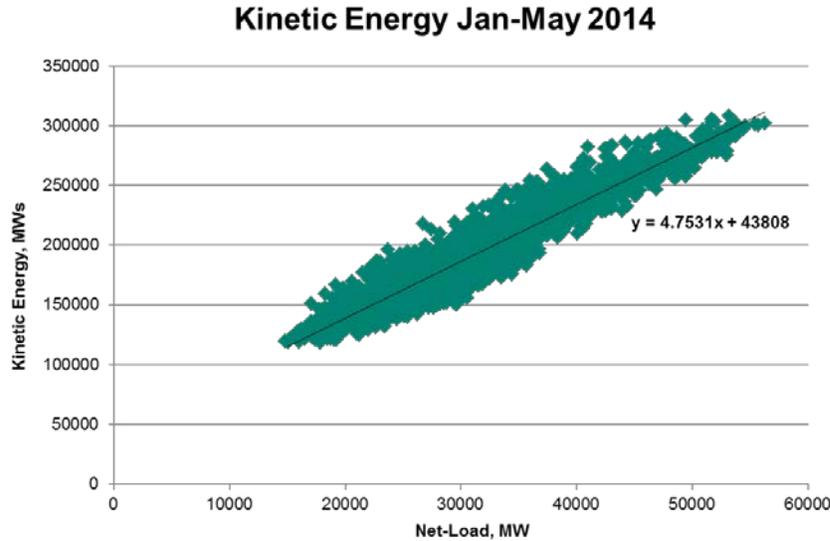


Figure A.1: Hourly System Inertia Jan–May 2014 Vs Corresponding System Hourly Net Load for ERCOT System with Linear Trend Line

2. Historic rate of change of frequency calculations for Measure 2 (initial frequency deviation following largest contingency at an interconnection level)

1. For each historic year and at minimum kinetic energy conditions KE_{min} , calculate RoCoF over the first 0.5 second window after the largest contingency ΔP_{MW} (as defined by the RCC in BAL-003-1 (e.g., RCC for ERCOT is 2750 MW)).

Rate of change of frequency over the first 0.5 second window after the contingency is calculated as:

- a. For systems where load damping constant D is not available:

$$\text{RoCoF} = (\Delta P_{MW} / (2 * KE_{min})) * 60 \text{ [Hz/s]} \quad (2)$$

Note: Here with load damping constant D assumed 0, RoCoF is independent of a time window (for first few seconds before governor response becomes effective).

- b. For systems where load damping constant D is available, use the following equation to calculate frequency deviation at 0.5 seconds:

$$\Delta f_{0.5} = \frac{\Delta P_{MW}}{D \cdot P_{load}} \cdot \left(1 - e^{\frac{-0.5 \cdot D \cdot P_{load}}{2 \cdot KE_{min}}} \right) \cdot 60 \quad \text{[Hz]} \quad (3)$$

P_{load} is system load during minimum kinetic energy conditions KE_{min} .

Corresponding RoCoF is calculated as

$$\text{RoCoF} = \frac{\Delta f_{0.5}}{0.5} \text{ [Hz/s]} \quad (4)$$

2. Calculate corresponding system frequency as:

$$f_{0.5} = f_o - 0.5 * \text{RoCoF} \quad [\text{Hz}] \quad (5)$$

Example:

- Example date 12/14/2011 4 am
- Load damping 2.44% per Hz
- Largest contingency $\Delta P_{MW} = 2750$ MW
- $P_{load} = 24744.66$ MW
- Pre-disturbance frequency $f_o = 60$ Hz
- $KE(t) = \text{sum}(H_i * MVA_i) = 147081$ MWs for that hour (i.e., sum of $H_i * MVA_i$ for all synchronous generators that were producing more than 5 MW in this hour)
- RoCoF for this hour (hour 8333 in a year) can be calculated as follows:

1. Convert load damping into % load change per 1 % frequency change.

$$1 \text{ Hz} = 1/60 = 1.67 \text{ \% of } 60 \text{ Hz}$$

$$D = 2.44/1.67 = 1.46 \text{ \% per } 1 \text{ \% frequency change}$$

$$2. \Delta f_{0.5} = \frac{\Delta P_{MW}}{D \cdot P_{load}} \cdot \left(1 - e^{\frac{-0.5 \cdot D \cdot P_{load}}{2 \cdot KE(t)}} \right) \cdot 60 = \frac{2750}{1.46 \cdot 24744.66} \cdot \left(1 - e^{\frac{-0.5 \cdot 1.46 \cdot 24744.66}{2 \cdot 147081}} \right) \cdot 60 = 0.272 \quad [\text{Hz}]$$

3. $\text{RoCoF} = 0.272/0.5 = 0.544$ Hz/s

4. $f_{0.5} = f_o - 0.5 * \text{RoCoF} = 60 - 0.5 * 0.544 = 59.728$ Hz

f_o is pre-disturbance frequency, assumed 60 Hz.

3. Plot system frequency after the largest contingency event calculated in step 2, assuming linear trend between time = 0 and time = 0.5 seconds, Figure A.3.

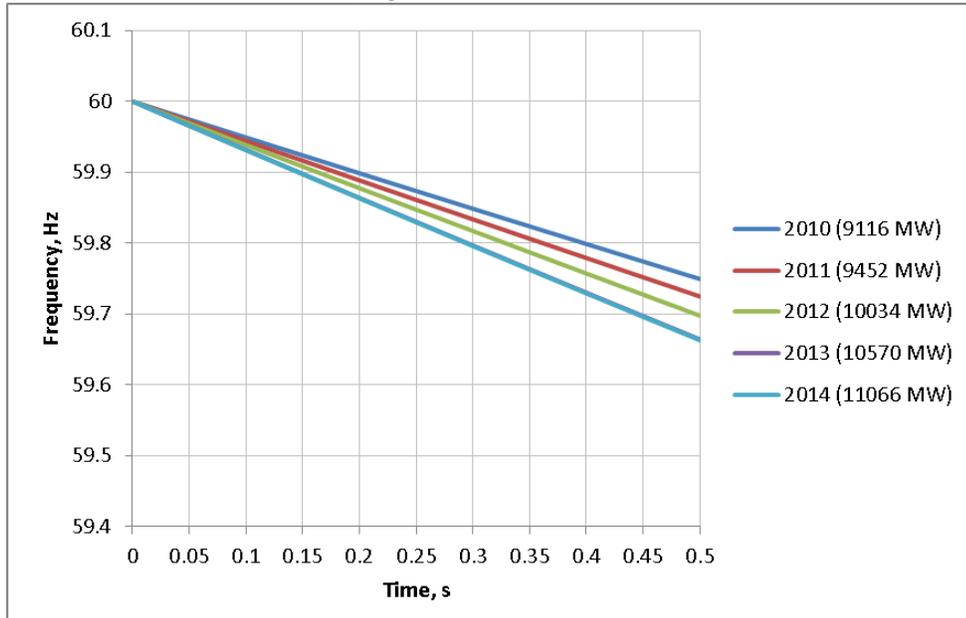


Figure A.2: Calculated System Frequency After 2750 MW Generation Trip, During Non-Synchronous Generation Penetration Peak in ERCOT for Years 2010-2014

4. Analyze system load and the non-synchronous generation penetration level during minimum kinetic energy conditions KE_{min} for several years. Derive trends that could be used to project minimum kinetic energy conditions for a future year (for e.g. coincidental non-synchronous generation and load during minimum kinetic energy hour in a future year). In the following sections, kinetic energy and RoCoF projections are made for the highest instantaneous non-synchronous generation penetration hour in a future year.

3. Analyze hours of highest instantaneous non-synchronous generation penetration in a number of historic years, to calculate future projections

3.1 Additional data requirements (from BAs in an interconnection):

- Installed capacity of non-synchronous generation-by-generation technology (e.g., wind-installed MW, PV-installed MW, etc.) in each studied historic year

3.2 Calculation procedure:

1. For each year and in each hour, calculate instantaneous non-synchronous generator penetration (NSGP) as $\chi(t) = P_{NSG}(t)/P_{load}(t)$;
2. In a year, find an instantaneous non-synchronous generation penetration peak, $\chi(t_{max}) = \max(P_{NSG}(t)/P_{load}(t))$ and an hour t_{max} that it encountered in.

Example:

In ERCOT on March 31, 2014, 2:00 am (hour $t = 2139$ in a year)

- the system load (including any dc exports/imports) was $P_{load}(2139) = 24617$ MW,
- total non-synchronous generation was $P_{NSG}(2139) = P_{wind}(2139) = 9699$ MW, all provided from wind generation
- non-synchronous generation penetration at the time was: $\gamma(2139) = P_{NSG}(2139)/P_{load}(2139) = 9699/24617 = 0.394$

Conducting similar calculations for each hour of 2014, we can see that on March 31, at 2:00 am, instantaneous non-synchronous generation penetration was the highest in the year (i.e., $\gamma(2139) = \max_{2014}(P_{NSG}/P_{load}) = 0.394, t_{max} = 2139$.)

3. For the hour of highest non-synchronous generation penetration, t_{max} , determined in step 2 above, calculate power production from each non-synchronous generation technology (e.g., wind, PV) as a share of the total installed capacity $\eta(t_{max})$ of this generation technology (e.g., $\eta_{wind}(t_{max}) = P_{wind}(t_{max})/P_{installed_wind}(t_{max})$ for wind generation, $\eta_{PV}(t_{max}) = P_{PV}(t_{max})/P_{installed_PV}(t_{max})$ for PV generation, etc.). If some non-synchronous generation resources are concentrated in certain geographical areas, η may be calculated separately for each generation technology in each geographic area.

Example:

For ERCOT’s example above, wind production, expressed as a share of the total installed wind generation capacity, $P_{installed_wind}(2139) = 11066$ MW, during highest non-synchronous generation penetration hour $t_{max} = 2139$, is: $\eta_{wind}(t_{max}) = P_{wind}(2139)/P_{installed_wind}(2139) = 9699/11066 = 0.88$.

For all studied historical years (2010–2014), $\eta_{wind}(t_{max})$ and $\gamma(t_{max})$ are shown in the table below along with underlying data.

	2010	2011	2012	2013	2014
Installed Capacity, MW	9,116	9,452	10,034	10,570	11,066
Non-synch. gen. penetration peak, $\gamma(t_{max})$	25.5%	27.4%	29.8%	35.8%	39.4%
P_{wind}, MW	6,483	6,772	7,247	8,773	9,699
Wind production in % of installed capacity, $\eta_{wind}(t_{max})$	71%	72%	72%	83%	88%
P_{load}, MW	25,427	24,745	24,328	24,488	24,617

Projecting kinetic energy and RoCoF at renewable penetration peak hour in a future year

4.1 Additional data requirements (from BAs in an interconnection)

- Expected installed non-synchronous generation, by generation technology, in a future year based on signed generation interconnection agreements (SGIA), financial commitments (FC), and other criteria, e.g., $P_{installed_wind_future}$

4.2 Calculation procedure

- Project system load P_{load_future} during non-synchronous generation penetration peak based on the analysis and findings from Section 1, step 4.

Example:

For ERCOT system it was found that during non-synchronous generation penetration peak hours for years 2011–2014, system load was nearly the same. Therefore, average system load from years 2010–2014, non-synchronous generation penetration peak hours, was assumed even for projected non-synchronous generation peak hours ($P_{load_future} = 24700$ MW) in future years 2015–2017.

- Apply installed capacity share factor $\eta(t_{max})$ (as calculated in Section 3.2 step 3) to the expected installed capacity of respective generation technology (and geographical location); e.g., $P_{wind_future}(t_{max})/\eta_{wind}(t_{max}) * P_{installed_wind_future}$, $P_{PV_future}(t_{max}) = \eta_{PV}(t_{max}) * P_{installed_PV}(t_{max})$, etc. This is the projected production by non-synchronous generation type during a forecast non-synchronous generation penetration peak in a future year.

Total non-synchronous generation during projected non-synchronous generation penetration peak in a future year is then $P_{NSG_future} = P_{wind_future}(t_{max}) + P_{PV_future}(t_{max})$.

Example:

For the ERCOT system, with the future load assumption P_{load_future} as per the previous example and expected non-synchronous generation capacity, $\eta(t_{max})$ and corresponding wind production $P_{wind_future}(t_{max})$ are projected for each year (2015–2017):

	2014	2015	2016	2017
Installed Capacity, MW	11,066	19,443	20,630	21,130
Non-synch. gen. penetration peak, $\gamma(t_{max})$	39.4%	69%	73.2%	75%
P_{wind}, MW	9,699	17,041	18,082	18,520
Wind production in % of installed capacity, $\eta_{wind}(t_{max})$	88%	88%	88%	88%
P_{load}, MW	24,617	24,700	24,700	24,700

3. Calculate projected net load, $P_{NL,future} = P_{load,future} - P_{NSG,future}$
4. Calculate projected system kinetic energy during non-synchronous generation penetration peak based on trendline obtained in Section 1.3 step 7 (e.g., linear trendline $KE = a \cdot P_{NL} + b$), at $P_{NL} = P_{NL,future}$.
5. Plot projected kinetic energy on the same figure as boxplots on Figure A.1 to obtain the figure below, which is identical to Figure 1 on Page 2.

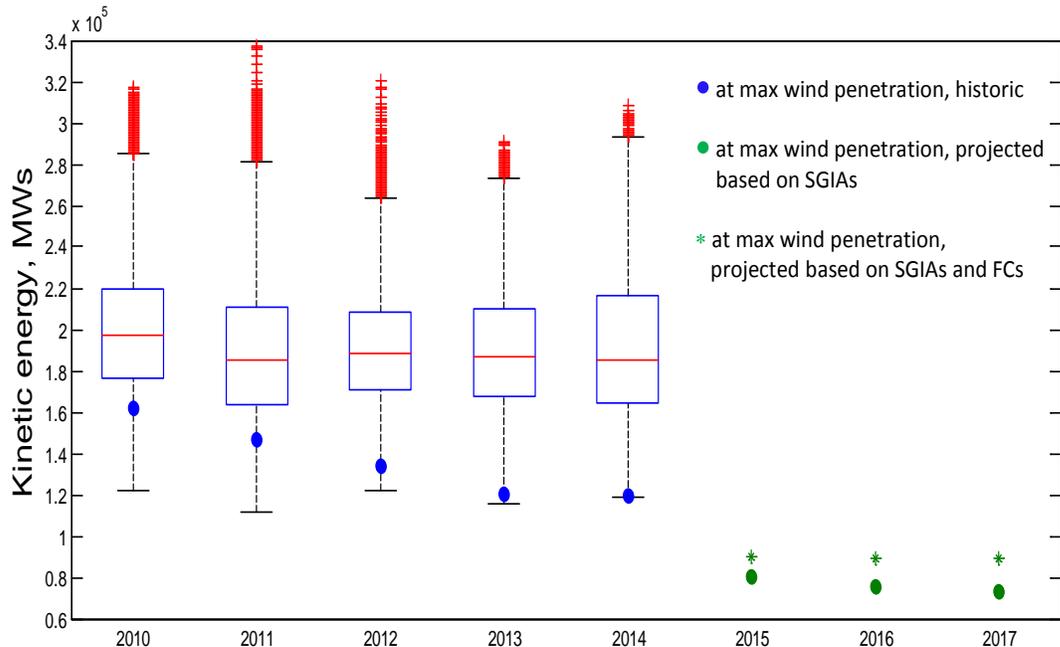


Figure A.4: ERCOT Historic Kinetic Energy Boxplots (2010–2017)

6. At an interconnection level, calculate corresponding RoCoF for the largest contingency ΔP_{MW} as described in Section 2, step 1, equation 2 (without load damping) or equations 3–4 (with load damping).
7. Calculate projected system frequency at 0.5 seconds after largest contingency with a RoCoF as calculated in previous step; use equation 5 in Section 0, step 2.
8. Plot projected system frequency after the largest contingency event, calculated in step 7 above, assuming there is a linear trend between time = 0 and time = 0.5 seconds. Plot it on the same figure as historical frequency Figure A.3 to obtain the figure below, which is identical to Figure 2 on Page 3.

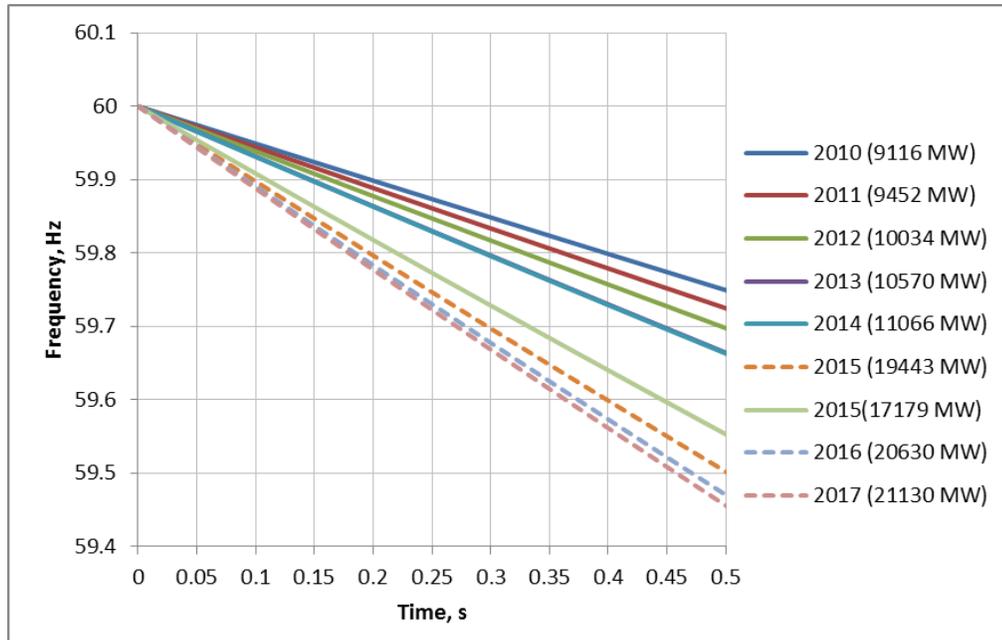


Figure A.3: Calculated System Frequency After 2750 MW Generation Trip (2010–2017)

Appendix B – Net Demand Ramping Variability

The electric grid is becoming more complex to operate, and the needed services to manage it are changing. As more states adopt renewable portfolio standards (RPSs), conventional resources are being displaced by VERs, which increases the level of uncertainty and variability in supply. Other energy and environmental policies, such as restrictions on CO₂ emissions, also impose operational constraints on conventional resources. On the demand side, changes are also occurring, and predicting demand in the day-ahead time frame is becoming more of a challenge due to energy efficiency, price-responsive loads, distributed solar PV, more variable loads, and plug-in electric vehicles.

In order to maintain load and supply balance in real time with higher penetrations of variable supply and less-predictable demand, BAs are seeing the need to have more system ramping capability, whether by adding more flexible resources within their committed portfolios or by removing system constraints to flexibility. Flexible resources, as described in this document, refer to dispatchable conventional as well as renewable resources, energy storage devices, and dispatchable loads. Having access to flexible resources gives a BA the ability to adapt to changing conditions while providing electricity safely, reliably, affordably, and in an environmentally responsible manner.

To identify system ramping capability needs, ERSTF uses the net load terminology to illustrate the expected variability of the system, assuming there is no curtailment of variable supply. The net load is calculated by taking the difference between total load and production from VERs. The future assessment of net load to determine changing operating conditions can also be determined by taking the difference between forecast load and expected VER energy production.

Many BAs have begun to perform detailed analysis on historical net load data and are beginning to understand the changing grid conditions. EPRI has recently published a technical paper called “Metrics for Quantifying Flexibility in Power System Planning.”⁴ This is the opportune time to embark on these analyses as several BAs have begun to experience operating conditions that require capabilities to mitigate the following:

- **Steep net-load ramps**, which require a BA to commit or shut down resources quickly to meet an increasing or decreasing electricity demand over short time periods.
- **Over-generation risk**, which can result in a BA experiencing high area control error (ACE) as supply exceeds demand, which contributes to high system frequency. In over-generation situations, BAs would have exhausted all measures, such as curtailing and shutting down conventional resources, as well as dispatchable VERs, as necessary.
- **Voltage control challenges**, which can occur as more conventional resources are displaced on days with low demand and high renewable energy production. The need for VERs to support system voltages has emerged.⁵
- **Decreased frequency response**, which can create potential challenges for some BAs to meet a frequency response obligation under BAL-003-1⁶ when fewer conventional resources are operating and available to adjust electricity production to maintain grid reliability.

To reliably balance supply and demand on a second-by-second basis, BAs with high levels of renewable resources may require their system’s overall ramp capability or a portion of their resource fleet to be more flexible.

⁴ <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=00000003002004243>

⁵ BAs do curtail renewable resources in real time should they lack the capability to control voltage.

⁶ BAL-003-1 “Frequency Response and Frequency Bias Setting” becomes effective in 2017.

Depending on a BA's existing fleet capability and operating practices, one or more of the following flexible characteristics would be required to:

- Sustain upward, downward, or both ramping capability needs;
- Meet fast-ramping needs for defined period of time;
- Change ramp directions quickly;
- Store energy or modify use;
- Respond to system changes in a short time;
- Operate dispatchable resources at low operating points;
- Start and stop resources multiple times per day;
- Provide frequency response post-contingency; and
- Have the capability to operate under automatic generation control (AGC).

Lack of sufficient system flexibility can result in:

- Inability to meet intra-hour upward/downward ramps
- Inability to meet multi-hour upward/downward ramps
- Potential over-generation conditions
- Inability to meet unanticipated variability due to lack of visibility of behind-the-meter solar PV
- Prolong imbalance and potential violation of BAL-001-1 "real-time balancing"
- Possible degradation of NERC's control performance standard 1 (CPS1)
- Potential inability to meet BAL-002-2 "Disturbance Control Standard" if a BA chooses to deploy contingency reserve to supplement upward ramping deficiencies
- Potential inability to meet a frequency response obligation as specified in BAL-003-1 "Frequency Response and Frequency Bias," which becomes effective in 2017

The ability to forecast operating conditions and commit resources with the right capability ahead of time could reduce the need for additional flexible capacity; however, in many instances accurate load, wind, and solar forecast during intra-hour time frames can be challenging.

EPRI's Metric for Quantifying Ramping Capability

In response to utility and ISO needs to better understand flexibility requirements, Electric Power Research Institute (EPRI) has been developing metrics, methods, and tools to assist in assessing the operational flexibility of an electric system.⁷ These are complementary to other efforts at regulatory agencies, utilities, and consultancies to assess operational flexibility issues. The EPRI work is described here to provide additional context on how operational flexibility requirements and the ability of the system to provide this flexibility can be measured.

A multilevel framework has been proposed with various levels of assessment corresponding to different levels of detail. The framework described is intended as additional analysis or modeling beyond existing planning processes and so is mainly aimed at areas likely to have significant operational flexibility requirements. Higher-level

⁷ <http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004243>

screening should suffice for many areas, while the detailed methods may only be needed for those where flexibility has been identified as an issue.

In Level 1, variability measures such as those described in the next section quantify variability over different time frames and for different expected frequencies of occurrence. These can be used to screen for requirements and to understand how this may change based on future load profiles, and how renewable energy, demand response, or other resources may affect the required flexibility requirements.

Level 2 screens the flexibility available from resources on the system; this includes a summary of the ramping ability of the resources, minimum turn down levels, start and shutdown times, and the minimum up and down times.

In Level 3 of the EPRI approach, more detailed metrics are considered. These metrics are based on post-processing of operational simulations that may already have been carried out for a system or on historical data. Based on expected unit commitment for each interval of the time period studied, the flexibility available from each resource can be measured for each hour of the study time frame. This is then compared to a flexibility requirement as defined in Level 1 to assess the sufficiency of the system to meet flexibility requirements. The requirement is normally based on the largest expected ramps up to a certain percentile under certain conditions. This results in three different flexibility metrics that can be assessed against system operations and can be calculated for both up and down ramping over different time horizons (typically 5 minutes to 8+ hours).

1. **Periods of Flexibility Deficit (PFD):** The PFD is a measure of the number of periods when the available flexible resources were less than the assumed required flexibility. The required ramping is measured based on the type of analysis described elsewhere in this document. This is done over all time horizons. Deficits over shorter time periods can be mitigated by improved short-term forecasting capabilities, dynamic and probabilistic reserve procurement strategies, reserve sharing between connected systems, and new fast-start, high-response resources. Over longer time periods, such as 3–8 hours, better long-term forecasts aid in the scheduling of large, slow-starting generation and intertie flows. In both cases, operational practices should be adopted first, but if there is still a flexibility deficit, new resources may be required.
2. **Expected Unserved Ramping (EUR):** EUR measures the amount of ramping that is not met for the system simulated. It is important to recognize that this does not mean the system will be short that much energy, but that this is the cumulative amount of shortfalls for ramping requirements based on large ramps. For example, the 97th percentile of ramp may be used, and the system may be short 20 MW for meeting that ramp over a given time horizon.
3. **Insufficient Ramp Resource Expectation (IRRE):** IRRE is a measure of the frequency of flexibility shortfalls over different time horizons. It differs from PFD in that it uses a probabilistic approach to determine the likelihood of not being able to meet net load ramps at each time interval. A distribution of ramps is created and compared to a distribution of available flexibility. This is similar to the loss-of-load expectation used in resource adequacy assessment, but is adopted for operational flexibility.

In Level 4 of the proposed framework, Level 3 analysis is extended to include a more complex representation of system constraints. While Level 3 considers the system as a whole, Level 4 adds consideration of how transmission may be physically available but contractually unavailable for the deliverability of flexibility. The deliverability over each time horizon and direction of ramping can provide information as to where flexibility constraints are most significant and how new transmission can help the system meet flexibility requirements.

These four levels of analysis are still under development and need further testing on real systems before being used in utility/ISO practice. The Level 3 metrics are data and modeling intensive and dependent on the assumptions made in the modeling of system operations. Therefore, they are suited to issues such as resource

expansion and determination of how different resources provide flexibility. Many of the measures are not purely a reliability measure, and instead may focus more on efficiency and economics as to how systems can manage flexibility needs.

Measure 6: Net Demand Ramping Variability

The data requirements and methods for the proposed metric are described below, using examples from CAISO and ERCOT. The intent is to provide both a historical and future view of the maximum one hour up, one hour down, three hour up, and three hour down net load ramps. The net load generally means the difference between total load and production from VERs, although other variable loads and generation types may be appropriately included. It is recommended that this analysis be done for the current study year, three recent historical years, and a projected year that is four years in the future. For example, the 2014 study year would include 2011–2013 historical years and the 2018 future year.

Building the Forecast Variable Energy Resource Portfolio

A BA can request the installed capacity for the expected renewable build-out for a study year from load-serving entities (LSEs) representing load within the BA’s balancing area. Typical data would include:

- The installed capacity for each wind, solar, and distributed resource that is under contractual commitment to the LSE;
- The location of each resource:
 - External resources: For resources that are external to the BA, additional information would be required to determine if the variability of the resource would be firmed by the sending BA or the receiving BA. For example, if the renewable resource would be imported on a dynamic schedule, then the receiving BA would need to include the variability in its ramping capability needs calculation similar to an internal renewable resource.
- Technology type (e.g., solar thermal, solar PV tracking, solar PV non-tracking, or distributed solar PV); and
- The expected on-line data. This is in order to include the flexible needs for the month and year after the resource has been in service.

The above information ensures that the assessment captured the geographic diversity benefits of renewable resources.

Load Build-out

It is recommended that a BA’s monthly net demand ramping variability be assessed using the most current full year of actual load data, preferably in one-minute increments. (If one-minute data is not available or the BA does not believe that it is necessary given the nature of their system, 5 minute data may be used.) The load growth factor could be obtained from the state’s Energy Commission (EC) in which the BA is located or any other reputable forecast provider entity responsible for providing load forecast to the BA for planning studies.

The BA can use the monthly peak load forecast to develop minute-by-minute load forecasts for each month. The BA can scale the actual load for each minute of each month of the most recent year using an expected load growth factor of the monthly peak forecast for the study year divided by the actual monthly peak.

Wind Profile Build-out

Existing Resources

- Use actual one-minute wind production data for the most recent year. For example, 2013 actual one-minute wind production data can be used to build 2018 one-minute wind production data.

Future Study Year

- Extract one-minute actual wind production data for the most recent year (e.g., 2013).
- If the expected wind addition is small compared to the installed capacity of the study year (e.g., 2018), the one-minute wind profile can be created by scaling the one-minute wind production data for 2013 using this factor: expected installed capacity in 2018 divided by the installed capacity in 2013.

$$2018 W_{1\text{-min}} = 2013 W_{\text{Actual}_1\text{-min}} * \frac{2018 W_{\text{Installed Capacity}}}{2013 W_{\text{Installed Capacity}}}$$

- If the expected wind addition is significant, then one-minute wind production data for the study year can be developed using NREL’s simulated profiles for a location in close proximity to the expected plant.

$$2018 W_{1\text{-min}} = 2013 W_{\text{Actual}_1\text{-min}} + 2018 W_{\text{Simulated}_1\text{-min}}$$

Solar Profile Build-out

Existing solar

- Use actual solar one-minute production data for the most recent year. For example, 2013 actual one-minute solar production data can be used to develop the profile for the study year 2018.

Future Study Year

- Develop one-minute solar production profiles using NREL’s 2005 solar profiles for a competitive renewable energy zone (CREZ) based on the profiles’ geographic locations and technology (e.g., solar thermal, solar PV tracking, and solar PV fixed). For example, if there is an existing 50 MW solar PV resource in a CREZ, and a new 25 MW solar PV is scheduled to come on-line during the study year in the same CREZ, then the BA can scale up the output of the 50 MW resources by an additional 50 percent to account for the new solar resource. This methodology maximizes the correlation between the load/wind and load/solar production profiles for a particular year for the vast majority of VERs. For solar resources located in new CREZs, the BA can develop production profiles using NREL’s dataset for specific locations based on expected installed capacity. New CREZs would not have the load/solar correlation, but the maximum three-hour ramps during the non-summer months are highly influenced by sunset, which is consistent with existing solar data during the non-summer months.
- Aggregate all new solar one-minute production data by technology.
- Sum the actual one-minute existing solar production data with the aggregated simulated solar data for all new solar installations.

$$\text{Solar } 2018_{1\text{-min}} = 2013_{\text{Actual}_1\text{-min}} + 2018_{\text{Simulated}_1\text{-min data}}$$

Calculating the Monthly Maximum One-hour and Three-hour Net-Load Ramps

Using the one-minute load profile and the expected wind and solar one-minute production profiles, the BA can develop minute-by-minute net-load profiles by subtracting the one-minute wind and solar profiles from the one-minute load profiles. The monthly one-hour and three-hour ramping needs can then be calculated by any of the three options outlined below. The maximum one-hour up and down ramping needs are determined by calculating the largest upward and downward change respectively within each consecutive 60 minute period. The maximum three-hour up and down ramping needs are determined in a similar manner using the largest ramp in each consecutive 180 minute period. As shown in Figure B.1, the maximum three-hour ramp can occur in less than three hours.

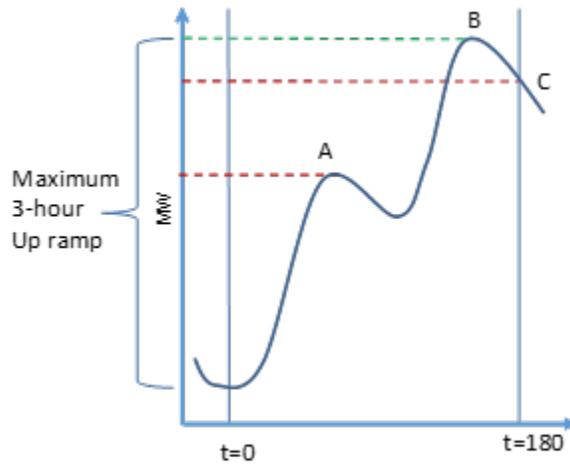


Figure B.1: Maximum Three-Hour Ramp

- The maximum net-load change in three hours can occur in less than three hours.
- The maximum monthly three-hour net load ramp within a three-hour period is the highest MW value reached within any three-hour moving window.

The one-hour and three-hour upward and downward net load ramp capacity can be calculated in several ways. The following are three potential options:

Option 1 – One-minute moving window

- One-Hour Ramp: $NL_{61} - NL_1, NL_{62} - NL_2, NL_{63} - NL_3, \dots, NL_{n+61} - NL_{n+1} \dots n \geq 0$
- Three-Hour Ramp: $NL_{181} - NL_1, NL_{182} - NL_2, NL_{183} - NL_3, \dots, NL_{n+180} - NL_n$

Option 2 – Five-minute moving window

- One-Hour Ramp: $NL_{61} - NL_1, NL_{66} - NL_6, NL_{71} - NL_{11}, \dots, NL_{5n+61} - NL_{5n+1} \dots n \geq 0$
- Three-Hour Ramp: $NL_{181} - NL_1, NL_{186} - NL_6, NL_{191} - NL_{11}, \dots, NL_{5n+181} - NL_{5n+1}$

Option 3 – Average of one-minute moving window

- One-Hour Ramp or Three-Hour
 $Up\ Ramp = Avg(NL_{t+4min}) \geq Avg(NL_{t-4min})$
 $Down\ Ramp = Avg(NL_{t+4min}) < Avg(NL_{t-4min})$

The results for all three options are fairly close. For simplicity, Option 1 is typically used.

Defining the BA’s Net Demand Ramping Variability

Each BA can calculate its one-hour or three-hour ramping capability needs using the following equation. Each BA can exclude the second part of the equation if it elects to neglect the spinning reserve portion of the contingency reserve in the flexible needs determination.

$$Flexibility\ Need_{MTHy} = Max \left[(3RR_{HRx})_{MTHy} \right] + Max \left(MSSC, 3.5\% * E \left(PL_{MTHy} \right) \right) + \epsilon$$

Where:

$\text{Max}[(3RR_{HRx})_{MTHy}]$ = Largest three-hour contiguous ramp starting in hour x for month y
 E(PL) = Expected peak load

*Replace $\text{Max}[(3RR_{HRx})_{MTHy}]$ with $\text{Max}[(1RR_{HRx})_{MTHy}]$ to calculate one-hour ramping needs
 MTHy = Month y

MSSC = Most Severe Single Contingency

ϵ = Annually adjustable error term to account for load forecast errors and variability method

Table B.1: CAISO's Expected Build-out Through 2018					
	2011	2012	2013	2014	2018
Large-Scale Solar PV	182	1,345	4,173	4,512	6,202
Small-Solar PV		367	1,100	2,200	2,630
Solar Thermal	419	419	419	1,051	1,631
Distributed PV					2,400
Wind	3,748	5800	5,894	5,894	8,557
Total					

The charts in Figures B.3 and B.4 show the one-hour and three-hour net demand ramping variability. As currently defined, the need is expected to increase for future years with the increase being more noticeable during the non-summer months. Figure B.3c shows the distribution of the one-hour up/down net demand ramping variability for 2011–2014 and the expected variability in 2018. Likewise, the charts in Figure B.4 show the distribution of the three-hour up/down variability for 2011–2018. The red shaded areas shown in Figures B.3c and B.4c represent two standard deviations from the mean of the one-hour and three-hour up/down variability, respectively.

Example of CAISO’s Historic Net Demand Ramping Variability Calculations and Trend for Future Projections

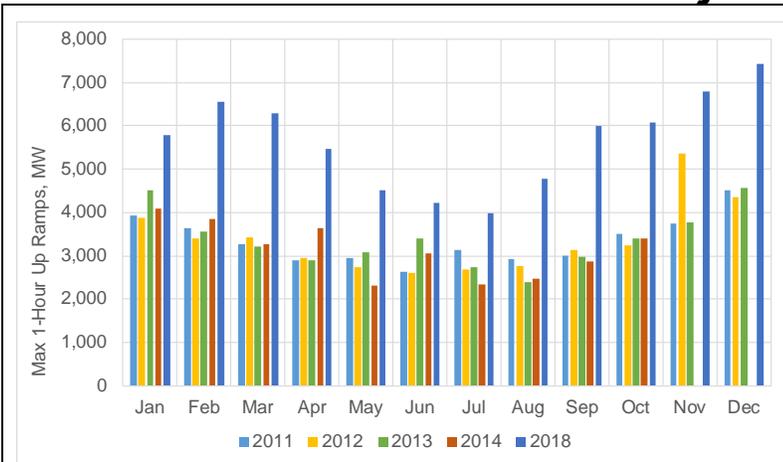


Figure B.3a: Maximum One-Hour Up Ramp

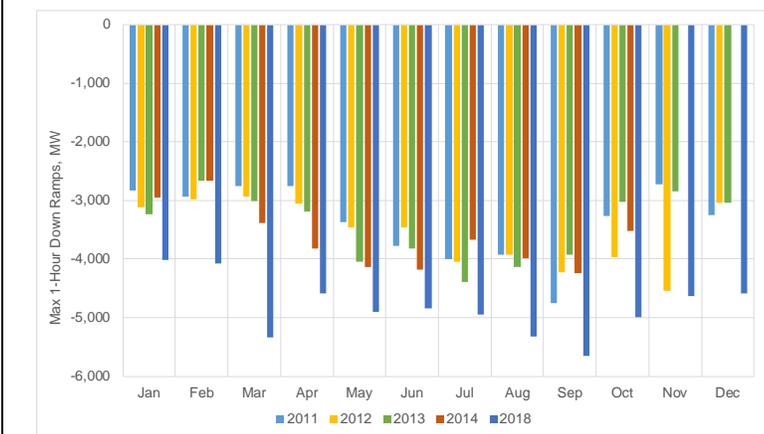


Figure B.3b: Maximum One-Hour Down Ramp

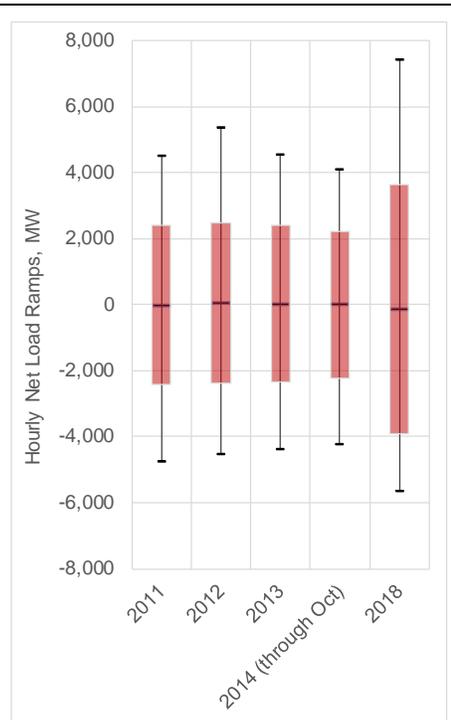


Figure B.3c: Yearly One-Hour Ramp Distribution

Red shaded area represents 2 σ from the mean

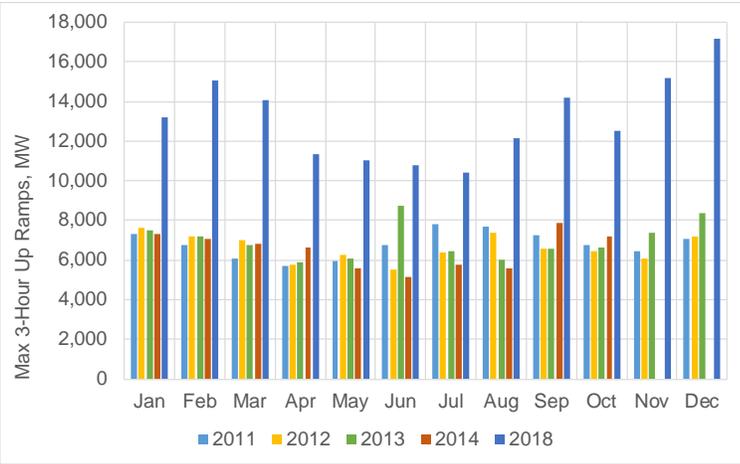


Figure B.4a: Max. Monthly Three-Hour Up Ramps

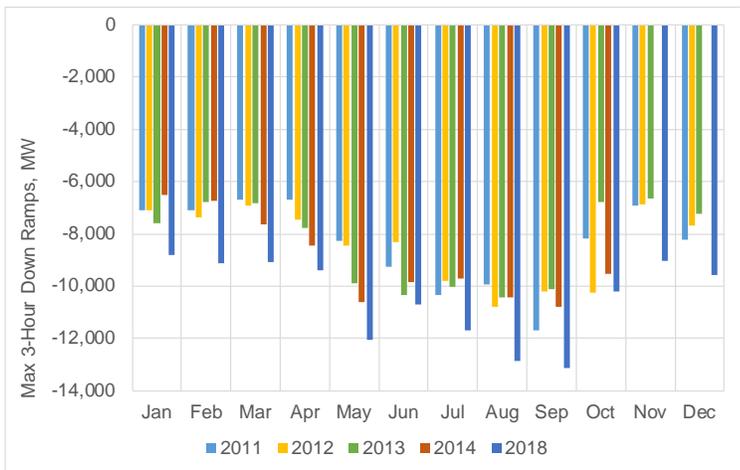


Figure B.4b: Max. Monthly Three-Hour Down Ramps

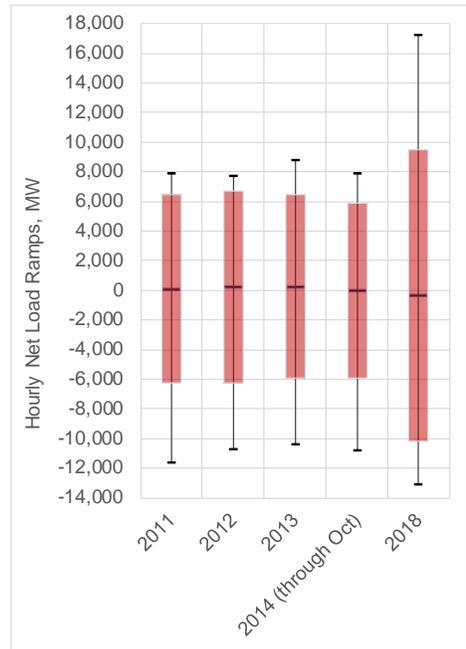


Figure B.4c: Yearly Three-Hour Ramp Distribution

Red shaded area represents 2σ from the mean

ERCOT

ERCOT Net Demand Ramping Variability Analysis for 2011–2014 and Predictions for 2018 Data Requirements:

1. Total ERCOT system load with one-minute resolution for 2011–2014
2. Total ERCOT wind power production with one-minute resolution for 2011–2014
3. Total installed wind generation capacity for each year, 2011–2014,8 Table B.2. In ERCOT, coastal wind is positively correlated with system load; therefore, the capacities are reported in the table as coastal and non-coastal wind to inform the analysis.

Year	Wind Capacity, MW	Coast Wind, MW	Non-Coast Wind, MW	PV
2011	9500	8433	1067	
2012	10458	9178	1278	
2013	10994	9313	1681	
2014	11703	10022	1681	
2018	17340 (with SGIA & FCs)			
2018 with PV	21130 (with SGIA)			6341 (Requests)

Calculation procedure and results:

1. From historical load and wind generation data, net load is calculated for every one-minute interval as load minus wind production.
2. One-hour net load ramps for every one-minute interval are calculated using 60 minute moving window:
 For example, the one-hour net load ramp is calculated for minute 61 as a difference between net load in minute 61 and net load in minute 1 (i.e., $NL_{61} - NL_1$).
 One-hour ramp: $NL_{61} - NL_1, NL_{62} - NL_2, NL_{63} - NL_3 \dots NL_{n+60} - NL_n$,
 Where n is number of one-minute intervals in a year minus 60 (i.e., $n = 525540$).
 Positive net load ramps correspond to net load up ramps and negative net load ramps correspond to net load down ramps.
3. Three-hour net load ramps for every one-minute interval are calculated using a 180 minute moving window:
 For example, for minute 181, the three-hour net load ramp is calculated as a difference between net load in minute 181 and net load in minute 1 (i.e., $NL_{181} - NL_1$).
 Three-hour Ramp: $NL_{181} - NL_1, NL_{182} - NL_2, NL_{183} - NL_3 \dots NL_{m+180} - NL_m$
 Where m is number of one-minute intervals in a year minus 180 (i.e., $m=525420$).
 Positive net load ramps correspond to net load up ramps and negative net load ramps correspond to net load down ramps.
4. In each studied year, find maximum of net load up ramps and maximum net load down ramps for every time frame (i.e., one-hour or three-hour), as 99.8th and 0.2nd percentile of net load ramp distribution;⁹ see Figures B.5 through B.8. There is no particular trend in net load ramps that can be observed based on

⁸ Note currently there is only 158.8 MW PV capacity registered with ERCOT.

⁹ Note that absolute maximum of net load ramps may be driven by a single event and may not be suitable for comparison between different years and trending.

historical data. This is partially due to the fact that installed wind generation capacity was only increasing by about 500 to 1000 MW a year. Also, it was observed that maximum load ramps are fairly close to maximum net load ramp values, while maximum wind ramps are much lower (about one-half of maximum net load ramps of one-hour ramps and about one-third of maximum net load ramps for three-hour ramps). This means that the highest net load ramps are “driven” by load ramps rather than wind ramps. The load ramps follow fairly constant diurnal patterns and are not expected to vary substantially from year to year.

5. Projected 2018 net load ramps are based on projected installed capacity of variable generation (i.e., wind and solar) in 2018.

For ERCOT Example 2, cases were considered (see Table B.2):

- 2018 case: the projected installed capacity of variable generation is based on planned projects with signed interconnection agreements and financial commitments.
- 2018 with PV case: the projected installed capacity of variable generation is based on planned wind projects with signed interconnection agreements and all solar projects that requested interconnection with ERCOT. This goal of analyzing this case is to look at potential impacts from rapid solar build-out.
- Note that all wind interconnection requests in ERCOT currently add up to 24.5 GW of additional capacity, and ERCOT believes it is not realistic to assume that all of them will be built by 2018.

AWS True Power provided ERCOT with hourly wind power generation patterns for hypothetical future wind generation plants. Each profile is representative of the historical wind output in a specific county. The profiles were used in this analysis to project hourly production for new wind power plants in 2018.

ERCOT also procured new hourly solar generation patterns. These patterns contain profiles for 254 Texas counties for four different types of solar technologies, single-axis tracking, fixed tilt, solar thermal, and residential. ERCOT selected the single-axis tracking profiles, which were used in this analysis to project hourly production for new solar plants in 2018.

DNV GL (former KEMA) ¹⁰ developed the methodology for creating high-resolution variable power production and load time series from hourly data. The parameters for this methodology are derived from historically observed variability. This methodology was used to produce time series with one-minute resolution for future load, wind, and solar generation.

Figures B.5 through B.8 show maximum net load up ramps and maximum net load down ramps for 2018 case and 2018 with PV case.

¹⁰ http://www.dnvkema.com/Images/EndUseDataStrategy_July2014final.pdf

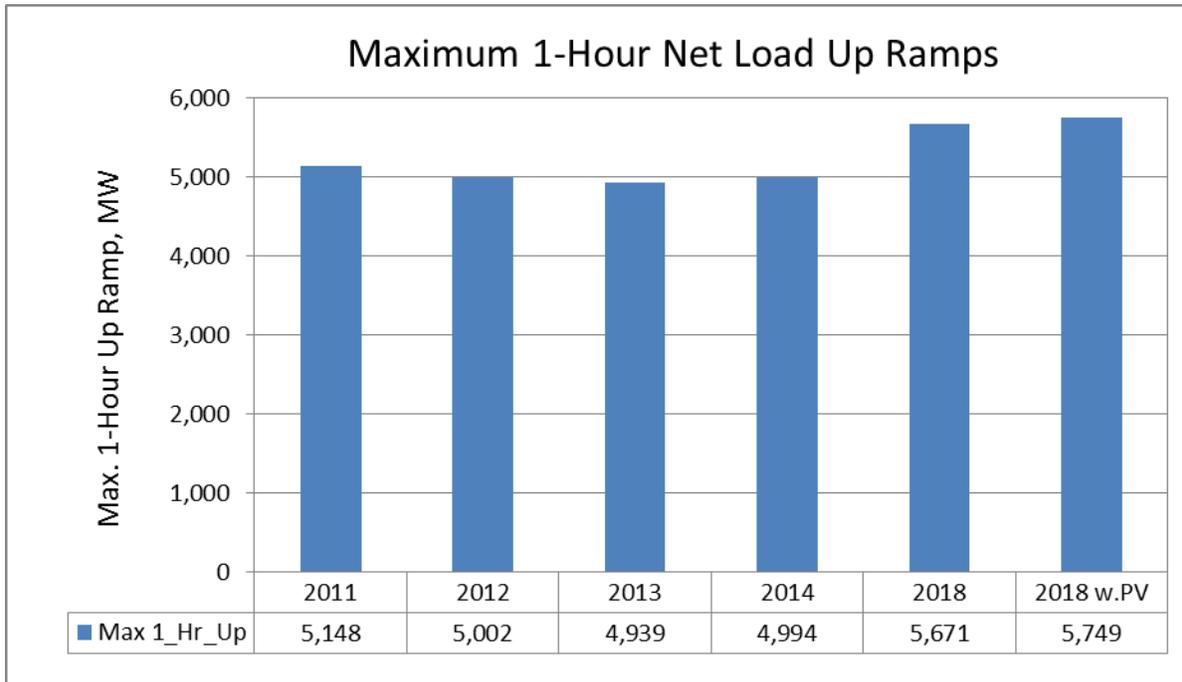


Figure B.5: Maximum (98th Percentile) One-Hour Net Load Up Ramps in 2011–2014 and Projected for 2018

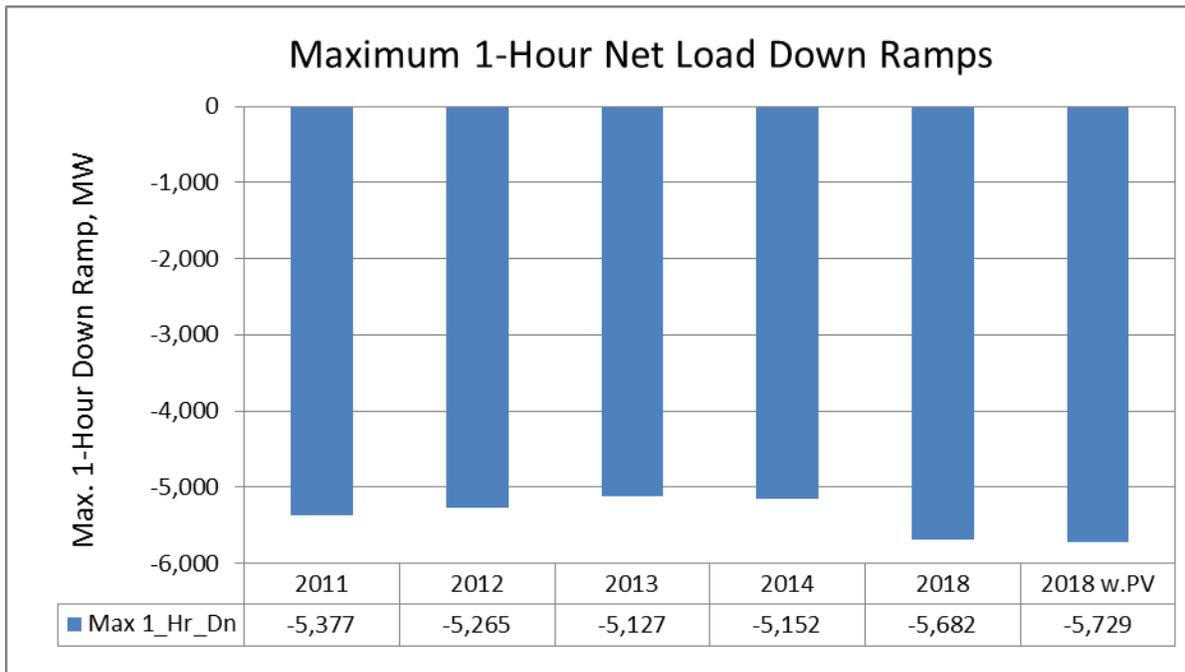


Figure B.6: Maximum (0.2nd Percentile) One-Hour Net Load Down Ramps in 2011–2014 and Projected for 2018

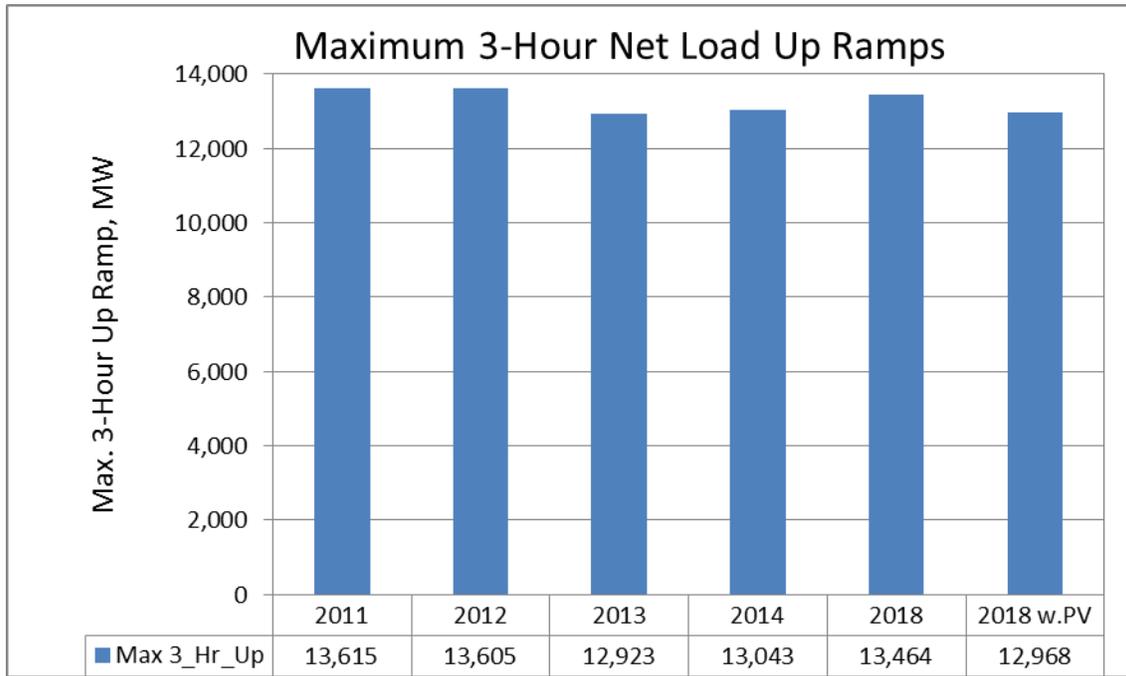


Figure B.7: Maximum (98th Percentile) Three-Hour Net Load Up Ramps in 2011–2014 and Projected for 2018

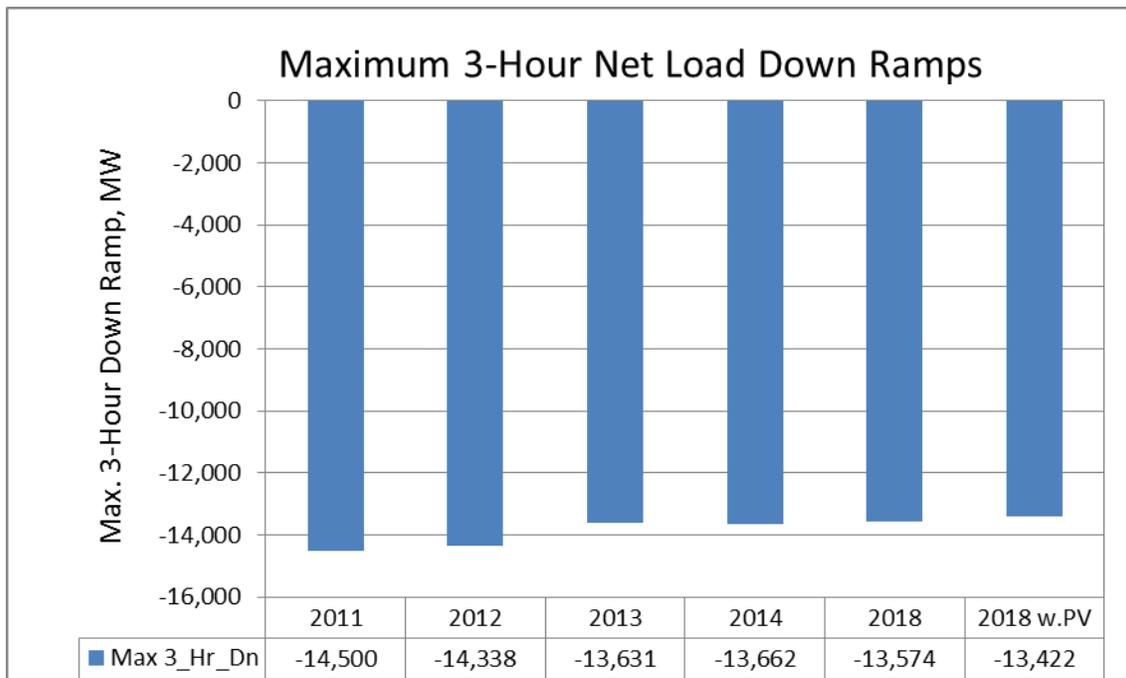


Figure B.8: Maximum (0.2nd Percentile) Three-Hour Net Load Down Ramps in 2011–2014 and Projected for 2018

- Figures B.9 and B.10 illustrate boxplots for one-hour and three-hour net load ramps, respectively, for historical years 2011–2014 and future projections in 2018. Boxplots are a convenient way to compare net load ramp statistics from several years on one plot.

On a boxplot, each box represents one year of net load ramps, as calculated in step 2 or step 3. On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, the whiskers correspond to +/- 2.7 sigma, which represent 99.3% coverage, assuming the data

is normally distributed, and the outliers are plotted individually (red crosses). If necessary, the whiskers can be adjusted to show a different coverage.

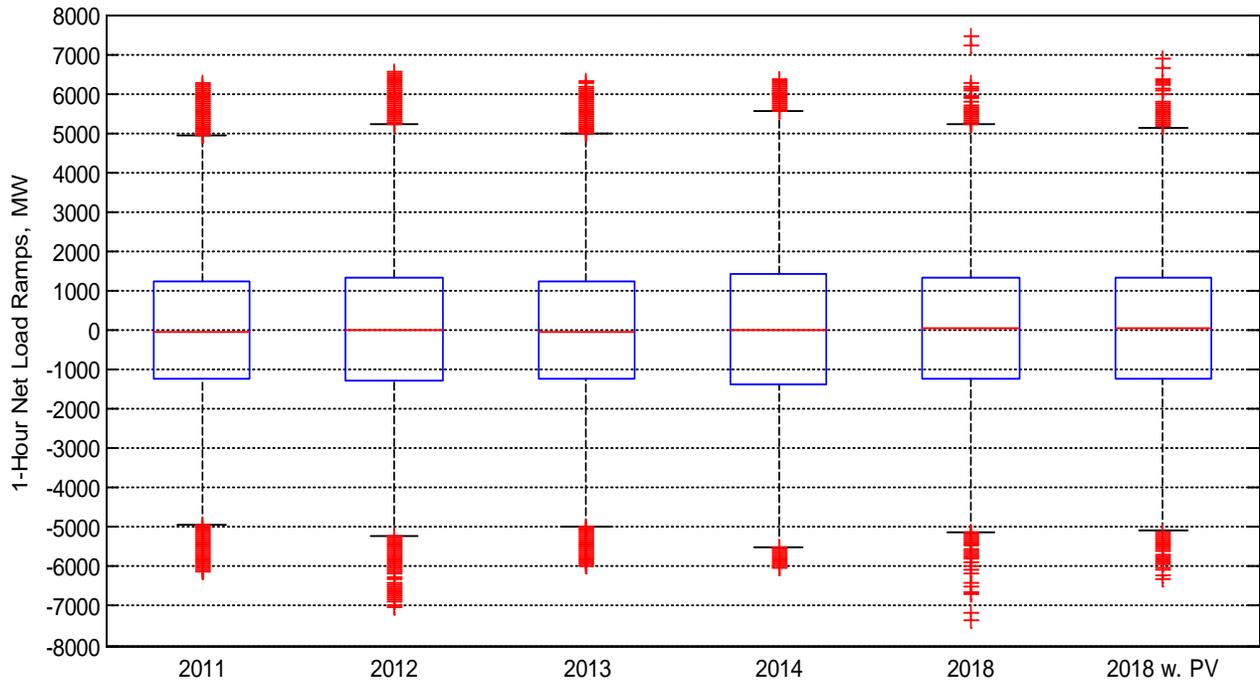


Figure B.9: Boxplots for One-Hour Net Load Ramps 2011–2018

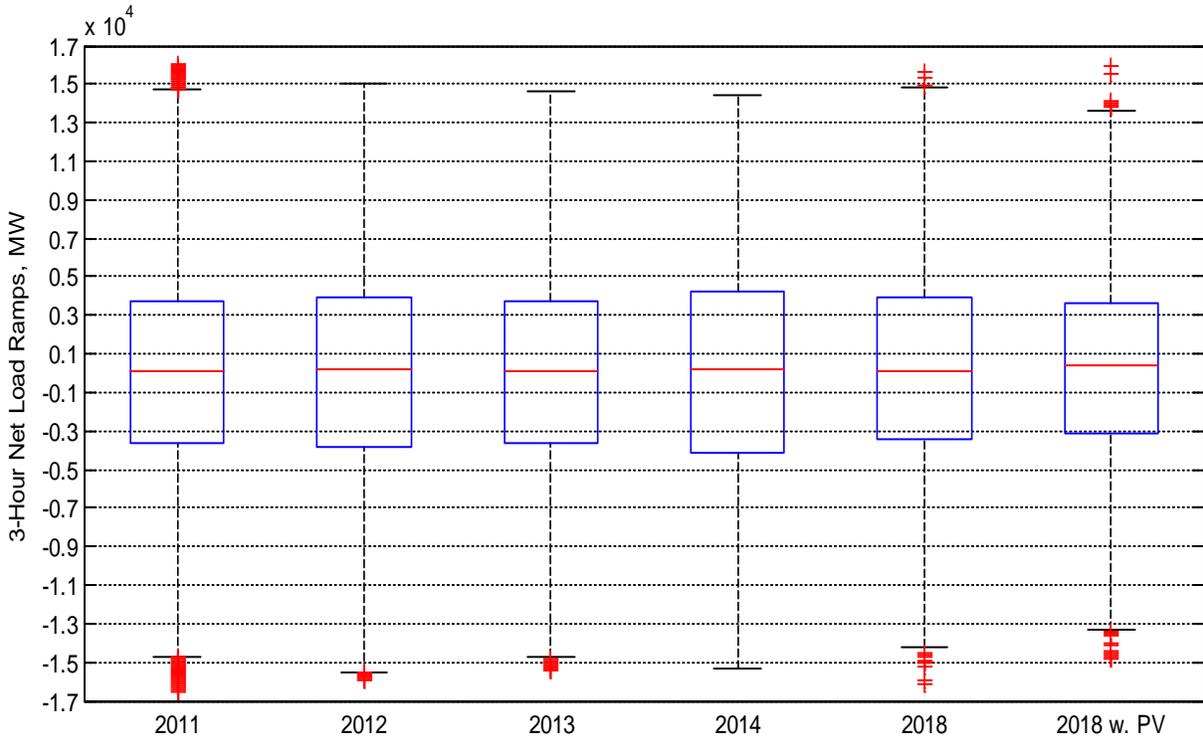


Figure B.4: Boxplots for Three-Hour Net Load Ramps 2011–2018

Appendix C – Reactive Power and Voltage Control

Background

The ability to control the production and absorption of reactive power for the purposes of maintaining desired voltages is critical to the reliable and efficient operation of the BPS. The process of controlling voltages and managing reactive power on interconnected transmission systems is well understood from a system planning and operating perspective. Key attributes include the following:

- System planners should design a system that has enough robust dynamic and static reactive capability (including both lagging and leading capability) to withstand the contingencies outlined in the TPL standards, specifically:
 - Determine the appropriate voltage levels and acceptable voltage bandwidths for reliable operation of the system under normal and contingency conditions;
 - Maintain voltages by managing reactive capability throughout the transmission system under normal and contingency conditions, including fault-induced delayed voltage recovery (FIDVR) situations and distributed generation ride-through;
 - Optimize reactive capability and voltages to maximize the efficient transfer of real power to load across the Bulk Electric System (BES) under normal and contingency conditions; and
 - Provide for operational flexibility under normal and abnormal conditions as determined in both steady-state and transient analyses.
- Transmission and Generator Owners should construct and maintain facilities that, at a minimum, meet with the system design requirements developed in the planning studies.
- The RC, TOP, and GOP should operate the system based on the requirements in the NERC TOP and VAR Reliability Standards.
- The RC and TOP should periodically review reactive and voltage performance of the system to ensure adequate reliability is maintained and to look for potential areas of enhancement moving forward.

Reactive support must be provided locally throughout the power system. Resources are generally controlled centrally because their coordinated operation is essential to maintaining reliability. Centralized control of reactive capability leads to efficient use of resources and ensures that there is an adequate reactive margin (the combination of on-line dynamic and static reactive reserves and off-line available dynamic and static reactive reserves) in response to emerging system conditions and contingencies.

Voltage and reactive power capability is a balancing act between the supply and demand of reactive power and the resultant impact on the voltage profile. Generators and various types of controllable transmission equipment, such as shunt and series devices, synchronous condensers, static VAR compensators, etc., are used to maintain voltages throughout the transmission system and maintain adequate reactive margins. When necessary, these resources are used to inject reactive power into the system to raise voltages or absorb reactive power to lower voltages. Requirements can differ substantially from location to location and can change rapidly due to shifting system conditions and load levels. For example, reactive power requirements will often vary significantly between day and night due to load level and pattern, dispatch, and system transfers.

There are other system devices that, while not directly supplying or withdrawing reactive power, will impact overall reactive and voltage performance of the system. As an example, transformer tap settings at the distribution level can impact the system-wide reactive capability. Likewise, the appropriate switching of series compensation can also have a significant impact.

Controlling the amount of reactive power that the load contributes to or withdraws from the transmission system can be extremely effective in managing overall BES voltage and reactive performance. The load power factor can be managed through coordinated adjustments of the step-down transformer taps and low-side voltage schedules as well as strategic placement of capacitors on the distribution system.

Reliability Considerations

Because reactive power requirements can change rapidly, especially under contingency conditions, the impact on voltage can be significant. There are other key considerations besides simply determining the needed amount of reactive capability. Resources with dynamic reactive power control capability (synchronous and converter-fed generators, SVCs, synchronous condensers, etc.) are needed to augment static devices (such as shunt capacitors and reactors) to maintain system reliability.

System planners must determine the optimal mix of dynamic and static reactive resources to handle inherent characteristics of the transmission elements in the power system such as reactive losses on the BES system when it is heavily loaded (high-surge-impedance loading) and line charging when the BES is lightly loaded. Equally important is the electrical location of those resources on the system. Because reactive power is not very transportable across the transmission system, the physical location must be optimized relative to the type, size, and characteristics of the reactive resources. It is imperative that the planners have a coordinated approach to managing reactive power and voltage control across the system that addresses not only supply-side and load-side concerns but also the controllability of voltage schedules, transformer taps, static device switching schedules, etc.

System operators must monitor actual voltages, adjust appropriate voltage schedules, and manage reactive power capability (dynamic and static) just as they must monitor and manage real power. Reliable operation requires the BES be able to withstand sudden disturbances and unanticipated loss of system components, including the loss of the reactive resources. Generation, along with other dynamic and static system resources, must provide stable voltage regulation and adequate reactive capability to ensure that the system can operate securely under steady-state conditions and during a myriad of potential contingencies. It is also important to avoid adverse interactions between voltage-regulating devices in tightly interconnected systems, to identify areas in the grid that are particularly challenging due to weak system conditions, and to mitigate situations where reliability may be jeopardized. It is therefore critical for the RC and TOP to have adequate situational awareness of their current voltages, on-line reactive resources, off-line reactive resources (available and unavailable), reactive loads, system conditions, etc., and understand the predictive voltage and reactive response of their system to potential contingencies.

Trends in the Industry

Changes in the resource mix of the generation fleet will impact reactive power management and require planning for controlling voltage. Traditional synchronous generators have typically been providers of dynamic reactive support and voltage control. In many cases, these units are being retired and replaced by gas, wind, solar, and demand response. The capabilities of these new generators must be considered and planned into the future system to maintain necessary levels of reactive support throughout the power system.

Some of these new renewable resources have utility-grade inverters, such as those used to couple modern wind and PV power plants with the BES, which can provide dynamic reactive power and voltage control capability. New wind and PV power plants are capable of providing dynamic reactive power control whether or not the plant is producing real power, similar to an SVC. As more resources using power electronics (e.g., wind, solar, FACTS devices, etc.) are integrated into the network, it is important that the controls of these resources be coordinated to maintain stable operation under all applicable system conditions.

Adequate analysis of the system characteristics and response will also require coordination with distribution owners and operators. The proliferation of distributed generation on the distribution/sub-transmission system creates an impact on voltage, and while there are evolving NERC standards (PRC, VAR) and IEEE 1547 revisions that will help, the potential impact on reactive performance behind the meter and on the distribution system must be factored in. Another impactful load-changing phenomena is FIDVR. FIDVR is a voltage condition initiated by a fault and characterized by the stalling of induction motors, such as those commonly used for air conditioner compressor motors, where initial voltage recovery after the clearing of a fault is limited and the recovery typically occurs in a period in excess of two seconds. These impacts on the distribution system can increasingly affect BES voltage performance.

Proposed Measures

As discussed in the body of this report and included here for completeness, industry should consider tracking several measures related to voltage support. The measures can be used to assess the strength of reactive support and quantify trends that may result from the changing resource mix of both generation and load. Regional differences may require some flexibility or customization of the measures. Systems vary widely in their topology and electrical characteristics (e.g., the total level of installed reactive resources, the type of generation resources, applicable local and regional voltage criteria, etc.). In general, measures may align with the BA construct under the NERC functional model, but because of the localized nature of reactive capability, more useful insights may be gained by monitoring the measures for appropriate sub-BA regions.

Measure 7: Reactive Capability on the System

1. Determine the dynamic reactive capability on the transmission system (rotating and non-rotating) per total MW load for the applicable areas at critical load levels (i.e., peak, shoulder, and light load) for the following:
 - a. Nameplate installed in the near-term planning study environment
 - b. Nameplate installed and actually online during real-time operations

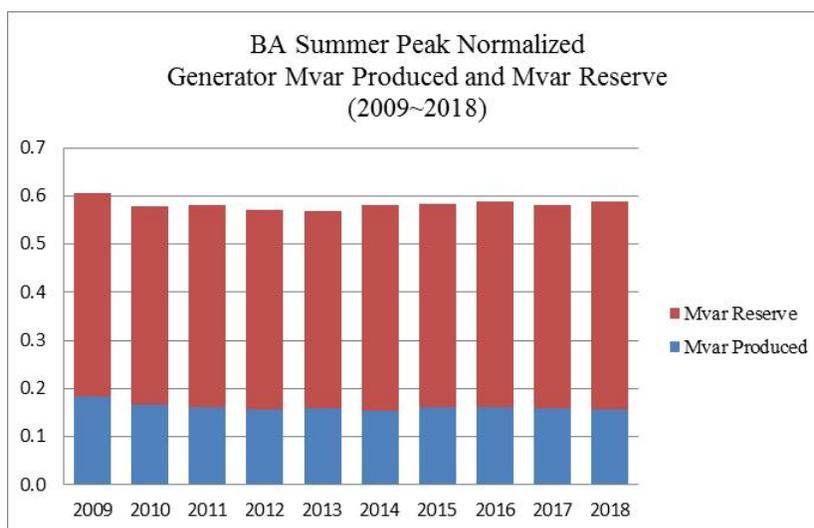


Figure C.1: Generator Mvar – Produced and Reserve at BA Level

2. Determine the static reactive capability on the transmission system per total MW load for the applicable areas at critical load levels (i.e., peak, shoulder, and light load) for the following:
 - a. Nameplate installed in the near-term planning study environment

- b. Nameplate installed and actually online during real-time operations

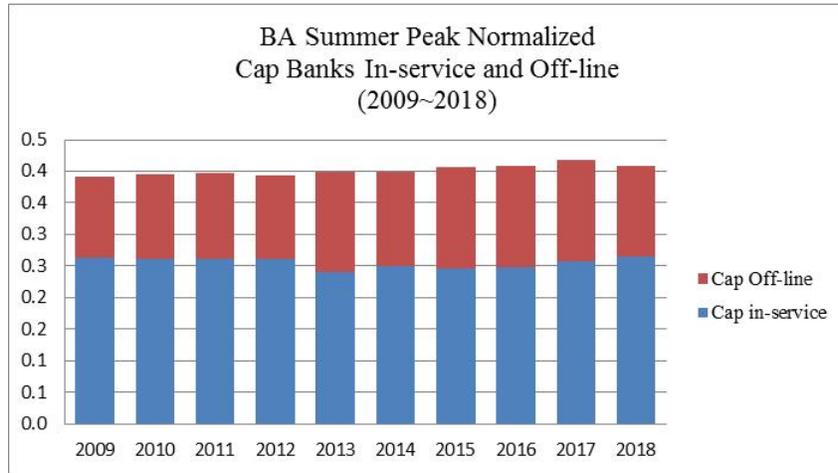


Figure C.2: Capacitor Mvar – Offline and Online at BA Level

- 3. Track Load Power Factor for distribution at the low side of transmission buses at the critical load levels (i.e., peak, shoulder, and light load).

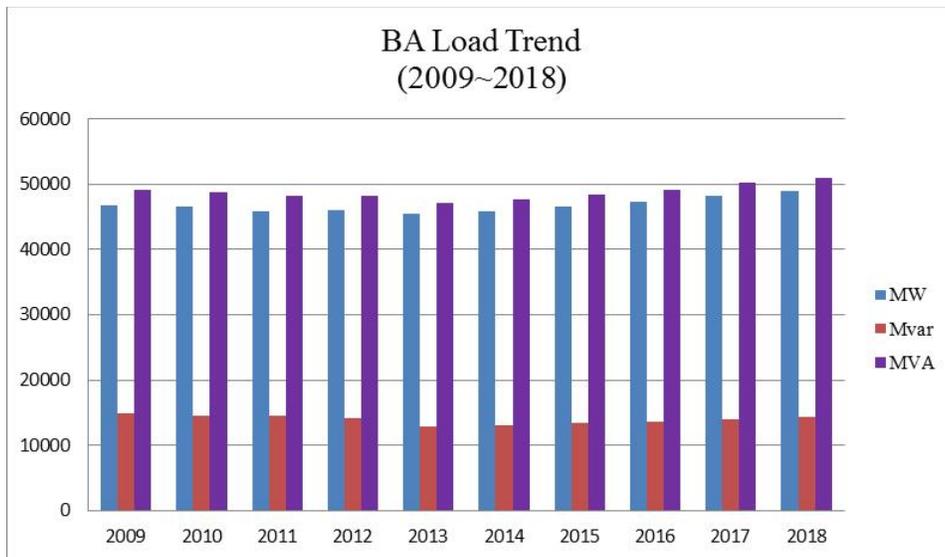


Figure C.3: Load Trend at BA Level

Measure 8: Voltage Performance of the System:

1. Based on established criteria, track the number of voltage exceedances that were incurred in real-time operations. This should include both pre-contingency exceedances and post-contingency exceedances.
2. Planners should consider ways to identify critical FIDVR buses and buses with low short-circuit levels. This would be a multi-part process:
 - a. Develop an appropriate criterion for determining which buses are at risk.
 - b. At a minimum period of every two years, develop the list of buses that exhibit poor characteristics.
 - c. Develop a remedial action plan to correct issues at critical buses.

- d. Document the implementation of any remedial actions taken.

Measure 9: Overall System Performance

1. Based on reactive capability and voltage performance, determine if the overall system strength poses a reliability risk. This could be accomplished by periodic review of system events that stresses reactive capability and/or degrades voltage profiles. Any analysis should endeavor to compare the system performance as designed in the planning studies to the real-time operations of the system. This type of comparison would provide useful insight into the success of the planning process in designing a robust system, document that the as-built system conforms to the requirements specified in the planning studies, and confirm the ability of operations to effectively manage those resources in real time. Note that some aspects of the proposed measures in accordance with various requirements in existing NERC standards, such as MOD-025, -026 and -033.
2. Adequate reactive margin and voltage performance should be evaluated in all operating horizon studies (seasonal, daily, etc.) and in state-estimated real-time contingency analysis.

It is recommended that these proposed measures be initially generated using the past few years of planning and operational data, if such data is available, to test the potential merits of tracking these indices over time going forward. Once their potential merit has been confirmed, a process for collecting data on future trends should be established.