UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)))	Docket No. RM18-1-000

REPLY COMMENTS OF FIRSTENERGY SERVICE COMPANY *ET AL.*[1]
IN SUPPORT OF THE GRID RELIABILITY AND RESILIENCE PRICING
NOTICE OF PROPOSED RULEMAKING

This proceeding is *not* about picking fuel supply winners and losers.

This proceeding is *not* about the reliability of natural gas pipelines.

This proceeding is *not* about the qualities of natural gas generators.

This proceeding is *not* about abandoning competitive electricity markets, such as they are.[2]

This proceeding is *not* about the Polar Vortex.

What this proceeding *is* about is *preserving generation assets with resiliency attributes* in Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") before they are lost forever so that the grid stays reliable and *resilient in the future*.

FirstEnergy proposed in its initial Comments a clear path for accomplishing this task—namely, the adoption by the Commission of *pro forma* Resiliency Support Resource ("RSR")

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[1] These Reply Comments are filed by FirstEnergy Service Company and its affiliates FirstEnergy Solutions Corp., FirstEnergy Generation, LLC, FirstEnergy Nuclear Generation, LLC, FirstEnergy Nuclear Operating Company, FirstEnergy Generation Mansfield Unit 1 Corp., Allegheny Energy Supply Company, LLC, Bayshore Power Company, Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company, Jersey Central Power & Light Company, Pennsylvania Electric Company, Metropolitan Edison Company, Waverly Power & Light Company, Monongahela Power Company, The Potomac Edison Company, and West Penn Power Company (all, collectively, "FirstEnergy").

[2] *See* Comments of FirstEnergy Service Company et al. in Support of the Grid Reliability and Resilience Pricing Notice of Proposed Rulemaking ("FirstEnergy Comments"), Ex. 3 (Gifford Aff.) ¶ 4 (discussing how RTO/ISO "competitive markets" are more aptly termed "Restructured Administrative Markets"). Unless otherwise noted, all citations to comments are to Docket No. RM18-1-000.

tariff provisions and an associated RSR Agreement that all RTOs and ISOs subject to the Final Rule must incorporate forthwith into their tariffs.[3] FirstEnergy made clear that revenues received by an eligible generator under the RSR Agreement would be *net* of any market revenue received by the generator in capacity, energy, and ancillary services markets. This was stated unequivocally in FirstEnergy's Comments and accompanying expert testimony.[4]

This critical point appears lost on those Commenters opposing the Proposed Rule. Simply put, if at the end of the various policy reforms being considered, the Commission truly fixes the markets to provide just and reasonable compensation to resilient generation, then payments under the proposed RSR Agreements should net to zero. That is why FirstEnergy does not object to the Commission continuing the ongoing RTO/ISO reforms in the hope that those proceedings fix the widely-recognized under-compensation issues in the longer term. But neither these longer-term reforms nor any other alternative means of implementing the Proposed Rule will prevent today's resilient generation from retiring prematurely. That is why the Commission must act now, and in the time frame stated in the Proposed Rule.

None of the alternatives proposed to the Commission, either in this proceeding or in others, are sufficiently concrete that they can be effectively enacted now to prevent resilient units

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3 FirstEnergy Comments § IV.B.

4 *Id.* at 44 ("The proposed compliance tariff provisions and RSR Agreement provide that, in exchange for a Resiliency Support Resource ('RSR') Unit remaining in operation and providing energy and ancillary services in times of need by the RTO/ISO, the RTO/ISO will ensure that the RSR Unit receives a payment each month equal to its full costs of operation and service . . . *less market revenues for capacity, energy, and ancillary services,* net of fuel expense and variable operations and maintenance costs . . . ." (emphasis added)); *Id.*, Ex. 7 (McMahon Aff.) at 3 ("Under the proposed RSR Agreement, the RTO/ISO . . . will pay to the RSR Unit Owner monthly an amount equal to the Monthly RSR Amount for the RSR Unit less the Market Compensation Adjustment and Performance-Related Payment Adjustments, if any, each month. . . . The Market Compensation Adjustment comprises the amount of any revenues received by the RSR Units related to the operation of the RSR Unit during the applicable month including, but not limited to, payments from the Transmission Provider for capacity, energy, and/or ancillary services provided by the RSR Unit, net of fuel expense and variable operations and maintenance costs incurred as a result of operating the RSR Unit during the applicable month.").

from retirement. And once at-risk units retire, they are not coming back. A failure by the Commission to act now could cause an increase in total energy and capacity costs in PJM alone of $90 billion over the next 15 years—a significant increase over projected PJM energy and capacity costs over the same period.[5] Thus, immediate and decisive action is needed by the Commission to prevent these retirements. Only FirstEnergy's proposal combines the detail, sufficiency, and speed necessary to accomplish this task. Only FirstEnergy's proposal lays out how the resilient units can be reasonably compensated within a market construct by using an approach substantively similar to how this Commission has accommodated similar policy choices in the past.[6] Only FirstEnergy's proposal allows RTOs/ISOs to dispatch generators in their markets in *exactly* the same way it is being done today.

In these Reply Comments, FirstEnergy explains that implementing the Proposed Rule using FirstEnergy's proposed RSR tariff provisions and *pro forma* RSR Agreement will not conflict with current RTO/ISO market rules or with ongoing price formation reform efforts. But to be clear, the price formation proceedings, while developing a robust record that existing RTO/ISO markets are not just and reasonable, did not evaluate how to compensate generators that provide resiliency to the grid.

The Reply Comments then respond to Commenters who conflate the concepts of resilience and reliability, discuss why existing market rules are insufficient to preserve resilient generation, explain that the Proposed Rule is consistent with the Commission's statutory

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[5] *See* Affidavit of Michael A. Rutkowksi ¶ 9 ("Rutkowski Reply Aff.") (Reply Ex. 2).

[6] *ISO New England, Inc.*, 147 FERC ¶ 61,173 (2014) (adopting exemption from minimum offer price rule for certain generation technologies), *reh'g denied*, 150 FERC ¶ 61,065 (2015); Order on Remand, *ISO New England, Inc.*, 155 FERC ¶ 61,023 (2016) (affirming exemption), *reh'g denied*, 158 FERC ¶ 61,138 (2017), *appeal pending sub. nom NextEra Energy Res. v. FERC*, No. 17-1110 (D.C. Cir. filed Apr. 3, 2017).

mandate and Congressional intent, and finally, demonstrate that the PJM Independent Market Monitor's cost estimate of the Proposed Rule is grossly exaggerated.

I. The Proposed RSR Tariff Provisions and Agreement Will Not Conflict with Market Rules and Reforms

There is a great deal of debate as to whether proposals by PJM and others to reform RTO/ISO markets—*i.e.*, to make them more efficient, send appropriate price signals, compensate resilient generators for the value they provide, and support grid reliability and resiliency—can be implemented at all, let alone effectively. But there is no credible argument that *any* of these proposals sought to address how to compensate resilient generators for the value that they provide to the grid. And there is no credible argument that any of these proposals can be implemented to address this issue in a time frame that would prevent the loss of resilient generation. The record is clear—whatever those reforms represent, the Nation cannot wait for such reforms to be adopted and implemented. The time to act is now.

Certain Commenters claim that the Proposed Rule will conflict with market rules and/or market reform efforts. But those arguments prejudge the outcome here and depend entirely on precisely how the Commission chooses to implement the Proposed Rule. FirstEnergy's proposed RSR tariff provisions and associated RSR Agreement will not conflict with market rules or any reform efforts. Rather, the proposed tariff provisions and RSR Agreement have been carefully crafted to fully accommodate the current "market"[7] structure as well as to encourage longer-term reform efforts.

[7] *See* FirstEnergy Comments, Ex. 3 (Gifford Aff.) ¶ 4 (discussing how RTO/ISO "competitive markets" are more aptly termed "Restructured Administrative Markets").

Most notably, the proposed tariff provisions and RSR Agreement would pay RSR Units *the difference* between a cost-based amount and the revenues it receives from the market.[8] Additionally, the tariff provisions and RSR Agreement have a must-offer provision. Thus, the RSR Unit must participate in the market—it cannot simply sit idly by and collect revenues. And the *more* the market compensates it, the *less* RTO/ISO customers will be required to pay under the RSR Agreement. The tariff provisions and RSR Agreement thus work wholly within existing market structures.

Indeed, if the markets are reformed in a manner that results in just and reasonable compensation to RSR Units, the net payments by the RTO/ISO to an RSR Unit should fall fully to zero, if not negative (which would happen if market revenues exceed the RSR Unit's cost-based compensation level). This fact alone should motivate RTOs/ISOs and stakeholders to finally fix the markets to provide just compensation to fuel-secure, resilient generation. The faster the markets are fixed, the faster the net payments to RSR Units will fall. That should be enough of a motivating factor to break the endless loop of study-discuss-study-discuss. But FirstEnergy emphasizes that the RSR tariff provisions and RSR Agreement must be put in place immediately. The implementation of these provisions does not prevent RTOs/ISOs from undertaking additional market reforms in the future. Failure by the Commission to provide cost support to generating units immediately will result in continued retirements and all will be for naught.

[8] The proposed RSR Agreement can apply to multiple eligible units collectively, and entities need not execute individual agreements for each eligible unit.

FirstEnergy also notes that the proposed RSR tariff provisions and RSR Agreement are fully consistent with calls by Commenters to permit regional differences in approaches.[9] The proposed RSR tariff provisions and RSR Agreement have been carefully drafted to be generally applicable and thus easily implemented by all RTOs/ISOs that are subject to the Final Rule (*i.e.*, all RTOs "with energy and capacity markets and a tariff that contains a day-ahead and a real-time market or the functional equivalent"). But as discussed in its Comments, FirstEnergy recommends that the Commission direct that RTOs/ISOs adopt the proposed RSR tariff provisions and RSR Agreement or propose alternatives subject to a "consistent with or superior to" standard (as the Commission has used in similar circumstances).[10] These alternatives, however, can and should be reasonably limited to changes in nomenclature, if applicable, to reflect the terminology used in the RTO/ISO's existing tariff. Additionally, certain provisions of the proposed RSR Agreement expressly recognize that RTOs/ISOs and RSR Unit Owners may desire modifications to make the agreement fit better within the existing RTO/ISO practices. However, such changes need only be ministerial in nature, as the proposed RSR tariff provisions and RSR Agreement can be immediately adopted and easily incorporated into the applicable RTO/ISO existing tariff structures.

The proposed RSR tariff provisions and RSR Agreement thus respect regional differences while still ensuring prompt action to prevent further generation closures, and properly balance

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[9] *See, e.g.*, Ameren Servs. Co. Comments at 10-12; Am. Public Power Ass'n ("APPA") Comments at 17; Cal. Indep. Sys. Operator Comments at 5; Edison Elec. Inst. Comments at 5-6; Entergy Servs. Co. Comments at 10-12; MISO Transmission Owners Comments at 13-15; National Grid Comments at 14-15; NEPOOL Participants Comments at 6-9, 12; S. Cal. Edison Co. & S.D. Gas & Elec. Co. Comments at 3; Vectren Comments at 3.

[10] *See, e.g.*, Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, 75 FERC ¶ 61,080, 61 Fed. Reg. 21,540, 21,598 n.434 (1996); Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, 104 FERC ¶ 61,103 at PP 26, 816 (2003). *See also* Ameren Servs. Co. Comments at 13 (asking the Commission to permit RTOs/ISOs to submit compliance filings subject to "consistent with or superior to" standard).

the needs for immediate action with the rights of RTOs/ISOs to maintain a certain level of autonomy.

II. Resilience Is Not Addressed by Current Reliability Policies

Resilience and reliability are separate and distinguishable attributes that are equally important to an electric generation unit or system. Certain Commenters appear to conflate or confuse the two, which has the effect of overlooking the importance of resiliency as an attribute necessary to protect the system from infrequent but extremely disruptive events, and to mitigate against potential future catastrophic events. Yet regardless of nomenclature, the current market compensation construct fails to address resiliency attributes in its reliability assessments. The Proposed Rule accounts for these shortcomings and seeks to preserve the resiliency of the electric system.

A. Reliability and Resilience Are Two Separate Attributes

A number of comments filed in response to the Proposed Rule appear to use the terms "reliability" and "resilience" interchangeably.[11] The terms, however, represent two separate attributes—both of which are integral to a well-functioning and secure electric grid that meets consumer expectations. NERC itself recognizes this fact.[12] As FirstEnergy's expert David Whiteley explains,

> Reliability is an attribute of the electricity supply system measuring the strength and ability of the system to supply

[11] *See, e.g.*, APPA Comments at 26-27 ("Resilience itself is not an explicit value in the RTO markets, although there is some overlap with the reliability standard that incorporates a 15 percent reserve margin."); Retail Energy Supply Ass'n Comments at 11 ("Grid resiliency[is] really a subset of reliability[.]"); Algonquin Gas Transmission LLC Comments at 4-7 (addressing reliability attributes in discussion of resiliency). *Cf.* NYISO Comments at 11 ("The NYISO's existing market design values resilience *as an element of* reliability." (emphasis added)).

[12] *See, e.g.*, Letter from Roy Thilly, Chair of NERC Board of Trustees to John Twitty, Chair of NERC Member Representatives Committee at 2 (Oct. 5, 2017) (requesting input as to whether NERC should "formally add resilience to its mission statement as recommended in the DOE Grid Study").

> customer demands in the planning (forward-looking) environment. Resiliency, in contrast, is an attribute of how the electric system responds to disturbances beyond those defined in reliability standards and the ability of the system to recover from those disturbances and return to normal operations, as well as mitigate against potential future catastrophic events.[13]

By conflating or confusing the two terms, many Commenters overlook and/or fail to adequately address the importance of resiliency as contemplated by the Proposed Rule.

Commenters who understand resiliency recognize that "while reliability and resilience have a related ultimate goal—provision of an adequate supply of electricity—they differ in terms of the operating conditions under which power is supplied."[14] Reliability—which is "well studied and well managed,"[15] and is considered at length by existing markets and rules—is centered on preventing generation shortages at peak load on a consistent basis. Resiliency, on the other hand, is "a more holistic evaluation of how the grid can anticipate, withstand, and recover from disruptive events"[16] such as the Polar Vortex of 2014, hurricanes, violent storms, deliberate attacks, or other catastrophes. And while a strong transmission system is needed to

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[13] FirstEnergy Comments, Ex. 5 (Whiteley Aff.) at 2.

[14] Elec. Power Research Inst. ("EPRI") Comments ¶ 4; *see also id.* ("A reliable system is one for which a continuous supply of electricity is provided under normal and reasonably credible contingent conditions. A resilient system is one that limits the discontinuity of supply and provides for reasonable restoration of power under extreme, low probability conditions."). *See also* PJM Interconnection, L.L.C. ("PJM") Comments at 18 ("PJM is examining resilience, as distinguishable from reliability[.]"); *id.* at 18-19 ("Resilience, as PJM and other entities define it, which is the putative focus of the DOE NOPR, relates to preparing for, operating through, and recovering from a high-impact, low-frequency event."); Amer. Elec. Power ("AEP") Comments at 2.

[15] AEP Comments at 4.

[16] *Id.* at 2. These definitions are consistent with those provided by FirstEnergy and experts in the field. *See also* Presidential Policy Directive 21, Critical Infrastructure Sec. and Resilience (Feb. 12, 2013) (FirstEnergy Comments, Ex. 27); ELEC. POWER RESEARCH INST., ELEC. POWER SYS. RESILIENCY: CHALLENGES AND OPPORTUNITIES 3 (Feb. 2016) (FirstEnergy Comments, Ex. 25); PJM INTERCONNECTION, PJM'S EVOLVING RESOURCE MIX AND SYS. RELIABILITY 6 (Mar. 30, 2017) (FirstEnergy Comments, Ex. 26); FirstEnergy Comments, Ex. 5 (Whiteley Aff.) at 2.

maintain a resilient grid,[17] resilient generation is critical as well. Further, while both transmission and generation are addressed by the NERC Reliability Standards, a system that is reliable is not necessarily resilient. And that represents the future state of the bulk power system unless the Commission acts, and acts now.

B. Irrespective of How Resilience Is Considered in Relation to Reliability, It Is Not Being Adequately Addressed

Whether resilience is considered separately from the existing reliability framework or whether it is considered an element of reliability, the current regulatory and market systems fail to address resiliency and appropriately compensate resilient generators. Although RTOs/ISOs such as PJM have recognized the need for resiliency,[18] they have yet to propose—let alone implement—any concrete action to address and compensate resilient generation. Some Commenters point to PJM actions such as revisions to its market rules, or Commission actions such as price formation reforms, to demonstrate that the RTO and Commission are taking steps to incorporate resiliency considerations more directly into its framework.[19] But as discussed in Part III.B, leaving aside the issue of whether RTOs/ISOs are inappropriately conflating resilience efforts with reliability programs, these efforts by RTOs/ISOs to address resiliency are simply not enough to preserve generation diversity and resilience in order to protect the electric grid. And even if they were effective for resilience compensation—which they are not—none can be implemented in a timeframe that would stem the tide of resilient unit retirements.

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[17] *See* PJM Comments at 13; EPRI Comments ¶ 5; Bipartisan Former FERC Commissioners Comments at 9; ISO/RTO Council Comments at 15.

[18] FirstEnergy Comments at 18 (quoting PJM INTERCONNECTION, PJM'S EVOLVING RESOURCE MIX AND SYS. RELIABILITY 33 (Mar. 30, 2017) (FirstEnergy Comments, Ex. 26)).

[19] *See, e.g.*, Office of Ohio Consumers' Counsel Comments at 5-6 (referencing PJM actions); AEP Comments at 2 (discussing PJM's price formation initiative); Calpine Corp. Comments at 22 (discussing potential PJM rule modifications); Duke Energy Comments at 6 (discussing FERC efforts to address resiliency).

Similarly, NERC's current reliability assessments do not explicitly account for resiliency.[20] To be sure, NERC has made some important and accurate findings regarding resiliency—namely, that the premature retirement of fuel-secure baseload generating units reduces resiliency. And as FirstEnergy noted in its Comments, NERC has stated that "[a]reas with limited fuel and/or limited resource diversity may be challenged [by rare events] and should increase their attention to resiliency planning."[21] Indeed, NERC's reliability assessments consider that "[c]oal and nuclear generation support reliability by providing dependable capacity, substantial essential reliability services in the form of inertia and voltage control, and fuel security."[22] But while fuel diversity and dependable capacity are critical elements of resilience—a fact acknowledged by NERC, Congress, and experts alike[23]—these alone do not result in system resilience. In other words, fuel diversity and dependable capacity are *necessary* but not *sufficient* conditions of system resilience.

Rather, for a generating unit or facility to be considered "resilient," it must have fuel security in the form of on-site fuel and stable fuel delivery, *and* the ability to continue operations

[20] N. Am. Elec. Reliability Corp. ("NERC") Comments at 5-6.

[21] FirstEnergy Comments at 19 (quoting N. AM. ELEC. RELIABILITY CORP., SYNOPSIS OF NERC RELIABILITY ASSESSMENTS: THE CHANGING RESOURCE MIX AND THE IMPACTS OF CONVENTIONAL GENERATION RETIREMENTS 4 (May 9, 2017) (FirstEnergy Comments, Ex. 29)).

[22] NERC Comments at 6. Further, NERC has classified the changing resource mix as a "high priority" risk to the electric grid. N. AM. ELEC. RELIABILITY CORP., STATE OF RELIABILITY 2017 7 (June 2017) (Reply Ex. 4); N. AM. ELEC. RELIABILITY CORP., ERO RELIABILITY RISK PRIORITIES: RISC RECOMMENDATIONS TO THE NERC BOARD OF TRUSTEES 10 (Nov. 2016) (Reply Ex. 5) (highlighting as three "high priority" risks the "changing resource mix," due to "[t]he rapid rate at which fuel costs, subsidies, and federal, state, and provincial policies are affecting the resource mix;" challenges to "bulk-power system planning" that are "closely tied to the changing resource mix because planners currently lack the ability to update or create system models and scenarios of potential future states to identify system needs based on the dynamic nature of the system;" and challenges to "resource adequacy and performance" linked to changes in the resource mix that are "altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability in real time").

[23] *See* Energy Policy Act of 2005, Pub. L. 109-58, § 1251(a)(12), 119 Stat. 594, 962 (2005) ("Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies."); FirstEnergy Comments, Ex. 6 (Chao Aff.) § II; FirstEnergy Comments, Ex. 5 (Whiteley Aff.) § IV.

in the face of extreme events.[24] Notably, the Proposed Rule does not differentiate between fuel types and is *not* limited by its terms to nuclear and coal-fired generation. If a natural gas plant, a hydroelectric impoundment plant, or a geothermal plant were able to satisfy the eligibility criteria listed in Section 35.28(g)(10) of the proposed regulations, then it too would be eligible to participate as a Resiliency Support Resource.

A resilient system must also have a sustainable or proven sustainable mix of different generation technologies and fuels.[25] NERC's reliability assessments, which purport to incorporate aspects of resiliency, do not currently fully account for these specific attributes, which are essential to the concept of resiliency. Rather, as explained in the attached Reply Affidavit of Dr. Henry Chao, "the [NERC Reliability] Standards focus on the planning and build out of the [Bulk Power System] to meet certain criteria or goals, but they do not mandate planning or build out requirements for generation or fuel supply certainty for generation."[26] In this regard, the purpose of Reliability Standard TPL-001-4 is to "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."[27] But as explained by Dr. Chao, "The scope of the planning required by TPL-001-4 is limited however because it only looks at the impact of

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[24] FirstEnergy Comments, Ex. 5 (Whiteley Aff.) at 7-8. By the same token, however, the fact that fuel security is only one element of resilience is not a reason to forgo action to ensure fuel-secure generation. For one thing, fuel security is a critical attribute of the generators covered by the proposed rule that cannot be replicated by other forms of generation. The resilience benefits provided to the grid by fuel-secure generators is at a distinct risk of being lost. Thus, while fuel security is only a part of what makes a unit or system resilient, it is a critical part that must be protected to ensure the ongoing resiliency of the grid.

[25] *Id.* at 8-9.

[26] Reply Affidavit of Dr. Henry Chao at 5 ("Chao Reply Aff.") (Reply Ex. 3).

[27] *Id.* at 6-7 (quoting NERC, Reliability Standards for the Bulk Electric Systems of North America, Apr. 1, 2016, TPL-001-4 § A.3 (Purpose)).

the loss of a generator or transmission component to the electric grid."[28] Thus, while TPL-004-1 is "certainly needed to help ensure reliability, [it] is insufficient to maintain resiliency and reliability in view of the current pace of retirement of nuclear and coal-fired generation."[29]

Additionally, addressing resource diversity alone is insufficient to protect resilience. Simply having a "diverse" generation mix does not necessarily lead to resiliency; rather, resiliency is about maintaining the right *proportions* of various forms of generation. While "fuel diversity index" calculations, such as that of PJM's Independent Market Monitor, may be of interest to some, they are ultimately irrelevant because they do not take into account having the *right* mix of resources with particular characteristics and the controls to maintain them. For example, "fuel diversity" does not capture the resilience benefits of on-site fuel.[30] A "fuel-diverse system" as measured by this index is equally susceptible to extreme events as a non-fuel-diverse system if the system has failed to consider what levels of each resource are appropriate and necessary to protect the grid. Diversity is not about having equal amounts of each type of resource—it is about having the *right* mix of resources needed to maintain resiliency and minimize risk.

Thus, while it is important to continue ensuring the presence of attributes like fuel diversity, resource adequacy, and dependable capacity in the electric system, these factors alone are insufficient to create a resilient grid that is able to withstand severely disruptive events and system perturbations. In reality, the attributes necessary to ensure a resilient system are currently insufficiently addressed by or entirely absent from existing regulatory and market systems.

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[28] *Id.* at 7.

[29] *Id.* at 8.

[30] *Contrast* Indep. Mkt. Monitor for PJM Comments at 29-30 (discussing the PJM Independent Market Monitors "fuel diversity index").

C. The Proposed Rule Addresses Resiliency

The Proposed Rule seeks to remedy these holistic shortcomings by specifically addressing resilience in order to protect the grid going forward. Although resilient generators *currently* provide resilience to the grid, they are not compensated for doing so. Resiliency is an engineering attribute that has been built into the system for decades, well before the markets were formulated. The markets have inherited and thus far enjoyed this benefit for free. However, markets are premised primarily on economic theory, and as a result, resilient generation is retiring and putting the system at risk. Thus, immediate action is needed to ensure those generators keep the grid resilient into the *future*.

Retirements of large, long-lived, fuel-secure, and resilient generators are irreversible, and new fuel-secure, resilient resources can take many years to build. As such, in the face of an imminent catastrophic event, retired generators cannot simply resume generation to alleviate the crisis. Thus, the premature retirement of fuel-secure generators threatens the resiliency of the Nation's electric system in a way that cannot easily be remedied in the face of a catastrophe. While FirstEnergy encourages additional efforts by RTOs/ISOs to address resiliency within their footprints, these efforts do not go far enough or work fast enough to protect the grid from the imminent threat presented by premature retirements of fuel-secure baseload generation.

Simply put, the imminent closure of resilient generation presents a clear and present danger to the Nation. If the Commission does not act now, it will end up with a long-lasting resilience deficit at a significant cost to customers. If the Commission does not act now, our national security will be put at risk.[31] If the Commission does not act now, the electric grid will

[31] *See generally* Exelon Corp. Comments, Ex. A (Prepared Direct Testimony of Dr. Paul Stockton).

face the risk of increased short-, medium-, and long-term costs as a consequence of a sustained regional outage due to lack of resilient units.

III. Existing Markets and Rules Are Insufficient, as Are Currently Contemplated Reforms; the Commission Must Take Decisive Action Now

Certain Commenters claim that existing RTO/ISO rules are sufficient to ensure reliability and resiliency,[32] or that contemplated reforms will do the job.[33] They are mistaken. No one can credibly assert that these efforts are designed to address compensating resilient generators for the value they provide to the bulk power system. Nothing short of decisive and immediate Commission action consistent with the Proposed Rule will stop the continuing closure of fuel-secure generation resources needed to ensure continued reliability of the power grid.

A. Existing Market Rules Will Not Preserve Resilient Generation

The recent onslaught of premature, economic closures of resilient generation in RTOs/ISOs demonstrates unequivocally that existing RTO/ISO market rules will not prevent these closures and, with them, the loss of grid reliability and resiliency. And while the grid may have reliable and resilient attributes *today*, that is a historic artifact of the vertically integrated utility model and does not address whether the bulk power system will remain resilient in the

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32 *See, e.g.*, PJM Comments at 16 ("[T]he analysis to date strongly indicates that market mechanisms *can effectively meet* the challenges posed by a changing resource mix." (emphasis in original)); Indep. Mkt. Monitor for PJM Comments at 26-27 ("The Capacity Performance design ties performance to payment for capacity and corrects or takes significant steps towards correcting the problems with the previous capacity market design."); Elec. Power Supply Ass'n ("EPSA") Comments at 28 ("The NOPR also fails to recognize that the ISOs and RTOs already have a number of tools at their disposal to address potential threats to grid reliability, including reliability concerns that could be regarded as implicating resilience issues."); *id.*, Sotkiewicz Aff. ¶ 10 ("the concept of resilience is not something new or different, but is something that is already embedded in NERC reliability standards and already accounted for in RTO markets such as PJM through the provision of regulation and frequency response reserves through markets, voltage support and reactive power through cost of service provisions, and resource adequacy through capacity markets."); EPRI Comments ¶ 29 ("supply resilience, if appropriate metrics are agreed upon, can be compensated through the capacity markets"). *Cf.* Ky. Indus. Util. Customers, Inc. Comments at 7 (recommending establishment of separate capacity market for grid reliability and resiliency resources).

33 *See infra* Part II.B and Comments cited therein.

future. The generation mix has changed dramatically over the last several years due to reduced costs, but at what expense to the future? This proceeding is about the future, and *ensuring* resiliency into the future.[34] Existing RTO/ISO market rules are, by design, incapable of accomplishing this task, which is a concern because once these units retire prematurely they will not come back. For decades, the market has been able to enjoy, for free, resiliency built on the back of captive customers paying the costs. But the resiliency benefits of these resources are disappearing right before our eyes. And, as Dr. David Hunger explains in his Reply Affidavit, "[i]n the future, extreme events should be expected to strain the grid, and it is not feasible at this time to know which resources will be needed, and which will not."[35] If these units retire, the costs to replace this benefit will be enormous.

One example that exemplifies the shortcomings of existing market rules in valuing resilience is the PJM Capacity Performance ("CP") construct that was approved by the Commission in 2015.[36] The PJM CP construct was designed to incentivize generation owners to make the investments necessary to ensure resource availability during times of system emergency under the threat of significant penalties if a unit is not available when called upon to maintain system reliability. The CP construct, however, fails to address the importance of fuel security arrangements in ensuring that resources can provide energy when needed to maintain system reliability during emergencies, such as the Polar Vortex. Specifically, despite recommendations by FirstEnergy and others to the contrary, the CP construct does not require

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[34] Certain Commenters suggest that fuel disruptions are not the cause of long-term customer outages. *See, e.g.*, Am. Petroleum Inst. ("API") Comments at 9-10; Advanced Energy Buyers Grp. Comments at 16-17. But that misses the point of the Proposed Rule and FirstEnergy's support of it. The Proposed Rule is intended to *prevent future* outages that might otherwise occur due to a lack of fuel-secure generation.

[35] *See* Reply Affidavit of Dr. David Hunger at 10 ("Hunger Reply Aff.") (Reply Ex. 1).

[36] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015), *order on reh'g*, 155 FERC ¶ 61,157 (2016), *order on reh'g*, 155 FERC ¶ 61,260 (2016).

that capacity resources have sufficient quantities of on-site fuel or back-up fuel, or that natural gas generators have firm natural gas supply.[37] Rather, the CP construct allows market participants to become CP-eligible resources with no demonstration of their fuel security arrangements.[38] Dr. Hunger recognized the danger of PJM's failure to directly address fuel security in the CP construct, submitting expert testimony explaining that "[p]ast auction experience suggests that market participants take an optimistic view of their ability to perform, especially if there is a low-risk opportunity to buy out any obligation later."[39] The failure, then, to adopt rules requiring resources to demonstrate their fuel security arrangements means there is no incentive for resources to make fuel security arrangements and, therefore resources can take the risk that they will have adequate fuel supplies to respond when called upon to maintain reliability. One need look no further than the results of PJM's capacity auctions under the now-implemented CP construct to see that the market reforms are not producing the expected results. Specifically, capacity auction clearing prices are lower now than in the auctions immediately preceding implementation of the CP construct, indicating that resources are not making the investments needed to improve resource performance, or ensuring the security of their fuel arrangements during system emergencies.[40]

[37] Comments and Limited Protest of the PJM Utils. Coal. at 52, *PJM Interconnection, L.L.C.*, Docket No. ER15-623-000 (Jan. 16, 2015).

[38] PJM Open Access Transmission Tariff, Attach. DD § 5.5A(a)(i).

[39] Comments and Limited Protest of the PJM Utils. Coal. at Attach. A (Affidavit of Dr. William Hieronymus and Dr. David Hunger) ¶ 48, *PJM Interconnection, L.L.C.*, Docket No. ER15-623-000 (Jan. 16, 2015); *see also* Hunger Reply Aff. at 10-11.

[40] Hunger Reply Aff. at 12.

RTO/ISO capacity markets are not preserving critical, resilient generation. These markets have existed in RTOs/ISOs for ten years,[41] and many reforms have been attempted to evolve the markets, yet resilient generators continue to close or are at-risk of closure for lack of sufficient market revenues. As noted by FirstEnergy in its Comments, lack of just and reasonable compensation to fuel-secure, resilient generators has *already* resulted in an unprecedented number of retirements in recent years, with many more plants at risk of premature retirement. The fact of the matter is that capacity markets value all capacity equally—there is no distinction in the annual product for fuel type or resiliency qualities.

Some Commenters, in particular the Independent Market Monitor for PJM, suggest that the current state of the markets is efficient, and thus that the current spate of resilient generator retirements is due to proper economic price signals.[42] As explained by Dr. Hunger, however, markets only provide signals that lead to efficient decisions on the part of market participants if the markets "efficiently price *all* valuable services provided to the system."[43] They do not. Because there is no mechanism for compensating resilience, an attribute that "has clear value to the system," existing markets "do[] not provide fully efficient price signals and, by definition, *cannot* result in efficient economic entry and exit."[44] The recent and severe pattern of nuclear and coal-fired generator retirements, therefore, does not indicate that there is efficient market entry and exit, as the Independent Market Monitor for PJM suggests.[45] In fact, the opposite is true: these retirements are caused by shortcomings in the RTO/ISO market rules that cause

[41] PJM, *PJM Markets Statistics at a Glance Fact Sheet* (Mar. 16, 2017), http://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/pjms-markets-fact-sheet.ashx.

[42] Indep. Mkt. Monitor for PJM Comments at 15, 19.

[43] Hunger Reply Aff. at 9.

[44] *Id.*

[45] *Id.* at 8-10.

undervaluation of resilience, and are exacerbated by government regulations and subsidies and changes in fuel prices.[46]

A megawatt of natural gas-fired generation that has only interruptible natural gas supply is valued by RTO/ISO capacity markets the same as a megawatt of nuclear generation with many months of fuel supply on site. This is not to say that nuclear capacity should replace gas-fired capacity. Natural gas-fired generation has different qualities than nuclear generation. For instance, some natural gas units have the ability to quickly ramp to follow load (although it is worth noting that such units capable of ramping either already are, or under contemplated reforms should be, compensated for such benefits). And nuclear generation has certain advantages over natural gas-fired generation, such as the fact that it does not face the risk of interruptions to its fuel supply. But RTO/ISO capacity markets value all such generation the same despite the fact that capacity is not a fungible product in the context of ensuring a resilient power grid. Unless and until RTO/ISO markets differentiate among sources of capacity, these markets will consistently fail to provide fuel-secure, resilient generation with sufficient revenues to maintain operations.

Further, capacity markets only look, at most, three years into the future.[47] But resiliency of the grid is a much longer-term issue. Fuel-secure resilient generation resources take far more than three years to plan and bring to commercial operation. As explained in the Affidavit of Samuel L. Belcher submitted with FirstEnergy's Comments, it can take approximately 15 years

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[46] *Id.* at 9-10.

[47] PJM Open Access Transmission Tariff § 1 (base residual auction is for three years out); NYISO Open Access Transmission Tariff § 1.3, Market Administration and Control Area Services Tariff § 5.13.2 (installed capacity auctions for "Capability Period[s]" of six months); ISO New England Open Access Transmission Tariff § III.13 (Forward Capacity Markets for one year periods).

to bring a new nuclear power plant to fruition.[48] RTO/ISO capacity markets simply do not look that far into the future, nor do they provide a guaranteed revenue stream of sufficient duration to support the funding of a new fuel-secure resilient generation resource. Capacity markets are designed in part to provide a source of guaranteed revenue to incentivize new generation construction. But only three years of revenue (at most) cannot fund a new resilient generation construction project. Not even close.

Similarly, reliability must run ("RMR") mechanisms are also insufficient to retain the necessary amount of fuel-secure, resilient generation. These mechanisms are designed, as their name implies, to prevent the closure of specific generating units in order to preserve short-term *reliability* until a transmission fix can be achieved. But as explained above and in the FirstEnergy Comments, reliability and resiliency are different attributes.[49] Indeed, resiliency promotes reliability. But, as explained by Dr. Chao in his attached reply affidavit, maintaining reliability—*i.e.*, complying with the NERC Reliability Standards during times of maximum load—does not mean that the grid will be resilient in the face of extreme weather or other high-impact events.[50] RMR constructs are simply too narrowly focused to be used to preserve generation and grid resiliency, as they only focus on those costs needed to keep the generator unit on in the short term.[51] As outlined in FirstEnergy's Comments,[52] other methodologies

[48] FirstEnergy Comments, Ex. 8 (Belcher Aff.) at 2-3.

[49] *See supra* Part II.A; FirstEnergy Comments § II; *id.*, Ex. 5 (Whiteley Aff.) § II.

[50] Chao. Reply Aff. at 6 ("The Reliability Standards do, of course, set forth reliability criteria and define design conditions and sensitivities to be considered in planning and operations, but these design conditions and sensitivities fail to encompass events—such as fuel unavailability or major natural gas pipeline disruptions—the likelihood and severe consequences of which we are only beginning to appreciate and understand.").

[51] FirstEnergy Comments, Ex. 7 (McMahon Aff.) at 7.

[52] FirstEnergy Comments at 46 (discussing Cash Flow Methodology and Cost-of-Service Methodology); *id.*, Ex. 7 (McMahon Aff.) at 5-13.

(including the Cash Flow Methodology, which is similar in concept to the RMR construct) would work to preserve resilient generators.

B. Current Reform Efforts Are Also Insufficient

Some Commenters suggest that existing efforts at RTO/ISO market reforms will solve the forthcoming resiliency crisis or that the Commission should allow such efforts to run their course.[53] This wishful thinking, while well intentioned, is misplaced. Efforts to reform RTO/ISO markets to get prices and price signals "right" have been going on essentially since RTO/ISO markets began.[54] But the markets are still not working correctly, and there is thus no reason to hope that future efforts will result in sufficient changes.

PJM, for one, proposes to study the issue and claims that its price formation initiatives should be allowed to run their course.[55] That is nothing more than an argument for delay and will not lead to a remedy for current unlawful rates any time soon. Too much talk and too little action is how RTOs/ISOs got into this problem in the first place. Seemingly endless efforts at discussion, study, more discussion, and more study have not resulted in any meaningful reforms that preserve fuel-secure, resilient generation. Why should the Commission or anyone else think that more talk and more discussion will yield any different result? Further, these efforts lack

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[53] *See, e.g.*, PJM Comments at 18 ("The DOE NOPR Ignores Efforts Underway to Address Resilience through Markets"); *id.* at 19-20 ("PJM and its stakeholders regularly examine resilience-related low-probability and high-impact events that could cause reliability impacts to the PJM system. . . . To advance resilience, PJM intends to create operating procedures that will define specific processes to be followed to evaluate the risk on the electric system of natural gas infrastructure vulnerabilities, with a clear understanding of natural gas infrastructure redundancy including generator dual-fuel capabilities such as on-site liquid fuel."); *id.* at 47 ("PJM also believes that reforms to its shortage pricing rules would benefit price formation and incentivize appropriate behavior that could mitigate operational reliability concerns. . . . Further, PJM is examining the level and shape of its operating reserve demand curves."); Exelon Corp. Comments at 20-21 ("PJM has proposed a straightforward solution to the pricing problem [of LMPs not reflecting the true cost of production]"—allowing an "inflexible unit to set LMP"); Calpine Corp. Comments at 21-22 ("ISOs and RTOs have already done substantial work on price formation that could provide a more market-friendly and efficient approach to address the concerns raised in the NOPR regarding premature retirements.").

[54] FirstEnergy Comments, Ex. 4 (Hunger Aff.) at 18-20.

[55] PJM Comments at 36-39.

details, are not targeted at resilience, and have an open-ended timeline. They are too little too late and will not solve the immediate and pressing problem of generation retirements putting resiliency at risk.

Further, this issue is too important, too pressing, and too critical to the Nation's security and grid reliability to leave to the never-ending vicissitudes of the so-called RTO/ISO stakeholder processes. Those processes, however well intentioned, call to mind the movie Groundhog Day, where the main character relives the same day over and over . . . and over and over some more.[56] While regional differences can and perhaps should be recognized, the problem here is inter-regional and cannot be solved in a timely manner via the RTO/ISO process.

Additionally, the roles and responsibilities of RTOs/ISOs are more temporally limited than the issue at hand. An RTO/ISO's role, first and foremost, is to operate the grid and energy and ancillary services markets in real time. RTOs/ISOs also have an important role to play in ensuring near-in future grid reliability and market stability. But the problem of retiring fuel-secure generating units is a long-term issue. The continuing premature retirement of fuel-secure, resilient units over the next few years will lead to decreased grid resiliency and reliability. It will also lead to increased costs for consumers as new gas-fired generators and gas pipeline infrastructure is built.[57] As stated by Dr. Hunger, "should the current fleet of resilient generators retire, in whole or in part, they will certainly not be available when needed. Thus, action is needed now and until such time when suitable, cost-effective replacement technologies for nuclear and coal-fired generation can be implemented."[58] Insofar as it can take 15 years to bring

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[56] *See* GROUNDHOG DAY (Columbia Pictures 1993) (a weatherman finds himself inexplicably living the same day over and over again).

[57] *See infra* Part V.C.

[58] Hunger Reply Aff. at 10.

a new fuel-secure, resilient unit online, today's retirements will—not may—lead to severe problems 5, 10, or 15 years from now. At that point, it will be too late to act.

NERC's current Reliability Standards and planning processes are also inadequate to preserve grid resilience and will not solve the problem in time. As explained by Dr. Chao, the NERC Reliability Standards "do not fully encompass the need for fuel security" that is necessary for the reliable and resilient operation of the grid.[59] These standards "were developed and determined sufficient based on the portfolio of generation resources in effect at the time [they] were developed," and therefore "do not fully capture or address the risk to the [bulk power system] of high reliance on natural gas as a fuel source for generation supporting the [bulk power system]."[60] The scope of NERC's planning process under Reliability Standard TPL-001-4 is limited, and does not take into account issues of fuel security or failures in the natural gas supply system.[61] The planning reviews under TPL-001-04 therefore "do not look out far enough in time to identify issues that might arise from premature, economic retirement of nuclear and coal-fired generation, nor do the reviews consider events such as pipeline outages that may adversely impact dozens of natural gas-fired generating units."[62] Moreover, as Dr. Chao explains, NERC has given no indication that it "has conducted a review of the [bulk power system] broader than that required under TPL-001-4 and current resource adequacy assessment practices."[63] Given the inadequacy of NERC's current standards and the lack of any indication that it can or will implement policies that can prevent the permanent loss of grid resilience, Dr. Chao concludes

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[59] Chao Reply Aff. at 6.

[60] *Id.*

[61] *Id.* at 6-7.

[62] *Id.* at 7-8.

[63] *Id.* at 8.

that "the Commission needs to act now to prevent the further closure of fuel-secure generation."[64] While further study and improvement of RTO/ISO and the NERC Reliability Standards are important, "it is appropriate for the Commission to first act to preserve the resilient units as contemplated in the Proposed Rule."[65]

We as a Nation, and the Commission as the steward of the public interest, cannot wait until these units retire and cause problems to the grid to take action. Action is needed now—*today*—and by the *Commission*, to prevent their retirement. For if they retire, they will be gone, and once problems begin, we cannot wait 15 years to build new fuel-secure, resilient facilities.

IV. The Proposed Rule Is Not Contrary to the FPA or Congressional Intent

As FirstEnergy explained it its initial Comments, the Proposed Rule is consistent with the Federal Power Act ("FPA") and a long history of Commission precedent in using its authority under Section 206 to remedy unjust and unreasonable rates. Commenters suggesting otherwise misunderstand the Proposed Rule and how the Commission has implemented previous, similar rulemakings, distort the Commission's jurisdiction and Congressional mandate, or both. The Proposed Rule requires RTOs/ISOs to file new tariffs that amend existing unlawful rates for resilient generators in order to assure those rates are just and reasonable, the same type of lawful enforcement of the Commission's mandate that it has repeatedly used with respect to other generators and aspects of the RTO/ISO markets in the past.

A. The Proposed Rule Comports with Congressional Intent

The Proposed Rule's goal of ensuring just and reasonable rates and protecting the resilience of the grid is consistent with Congressional intent as expressed in the FPA and the

[64] *Id.*

[65] *Id.* at 9.

Energy Policy Act of 2005. Certain Commenters, including PJM, suggest that the Proposed Rule is contrary to Congressional policy promoting competition and the development of wholesale markets.[66] These Commenters misstate Congressional policy and discuss only a limited portion of the Commission's statutory mandate.

First, the Commission's fundamental duty under Sections 205 and 206 of the FPA is to ensure "just and reasonable" rates for the wholesale sale of electric energy.[67] The Commission "is not bound to any one ratemaking formula" in carrying out that mandate.[68] Indeed, the electric grid is currently operated under an amalgam of cost-based and market-based regulatory structures in which generating units in RTOs/ISOs are compensated through a combination of bid-based capacity and energy markets, RTO uplifts, a variety of out-of-market payment schemes, and cost-of-service regulation mechanisms.[69] Whatever wish Congress may have for the Commission to pursue competitive markets clearly does not preclude the Commission from approving or mandating cost-based mechanisms as well, especially where, as here, the proposal can be accommodated within the existing market structures.

Second, Congress has tasked the Commission with ensuring the reliability of electric service. Under the Energy Policy Act of 2005, the Commission certified NERC as the Electric

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[66] PJM Comments at 29-30; PJM Power Providers Grp. Comments at 4-5.

[67] 16 U.S.C. §§ 824d, 824e.

[68] *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. 527, 532 (2008).

[69] As explained in FirstEnergy's initial comments and the affidavits of Mr. Gifford and Mr. Hunger, the RTO/ISO markets are administrative constructs that layer limited auctions for capacity and energy on top of an array of state and federal regulations. *See* FirstEnergy Comments § I.B; *id.*, Ex. 3 (Gifford Aff.) § IV; *id.*, Ex. 4 (Hunger Aff.) § II. The RTO/ISO markets contain many distortions and flaws that prevent proper price formation and true economic efficiency, as the RTOs/ISOs themselves recognize in their continuing efforts to update their rules. *See e.g.*, PJM Comments at 39 (describing the "problems PJM is experiencing" due to increased reliance on gas-fired generation); ISO New England Comments at 9-10 (stating that "ISO-NE is concerned about the region's gas dependence" and that it is studying winter operations to try to understand "the region's fuel-security risks"); NYISO Comments at 6-7 (describing NYISO's ongoing attempts to fix its price formation issues).

Reliability Organization tasked with developing and enforcing (under the Commission's oversight) reliability standards in order to "provide for an adequate level of reliability of the bulk-power system."[70] Congress's view of reliability encompasses the safe operation of the power system "so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."[71] Actions that support and maintain the resilience of the electric grid, including the Proposed Order, further this explicit Congressional policy. NERC's reliability standards do not and cannot ensure reliable service if the grid is vulnerable to fuel security risks due to unjust and unreasonable wholesale rates that artificially depress compensation for fuel-secure generators. The Proposed Rule's goal of preventing retirements that would exacerbate that risk is thus aligned with—not contrary to—Congressional policy.

Third, although the Commission has promoted open access to transmission and the development of regulated electricity markets through its rulemakings, the goal of these proceedings has always been to ensure fairness and efficiency, not simply to create unfettered competition for competition's sake. The Commission routinely intervenes to fix distortions where they result in unjust and unreasonable rates,[72] including by allowing or requiring cost-based rates in situations where market-based mechanisms are not properly functioning.[73] Promoting competition when possible is not the same thing as mandating market mechanisms even when markets fail to create just and reasonable outcomes and rates, and Congress has never

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[70] 16 U.S.C. §§ 824o(b), (c)(1).

[71] *Id.* § 824o(a)(4).

[72] FirstEnergy Comments § III.B (collecting rulemakings in which the Commission has amended open access tariff rules and RTO/ISO market rules to remedy unjust, unreasonable, and unduly discriminatory rates and market conditions).

[73] *Id.* § I.B; *id.*, Ex. 4 (Hunger Aff.) § II (describing a variety of cost-based mechanisms used in today's RTO/ISO administrative "markets").

suggested that it seeks to undo the basic structure of the FPA or the fundamental principle of electric utility regulation that "a regulated utility is allowed to recover from ratepayers all expenses incurred . . . plus a reasonable return on capital."[74] Commenters are thus incorrect to suggest that the Proposed Rule's use of cost-of-service rates to ensure resilient generation is somehow contrary to Congressional or Commission policy.

Commenters have also exaggerated the impact of the Proposed Rule on the existing regulatory framework and on RTO/ISO markets. PJM, for example, breathlessly exclaims that the Proposed Rule is a "direct assault" on its markets and will "fundamentally undermine" competition.[75] This claim is demonstrably wrong when considering the limited scope of the Proposed Rule and the breadth of existing regulatory framework. A large number of generators within the RTO/ISO regions are currently under cost-of-service regulation; indeed, the RTO/ISO "markets" have coexisted with cost-of-service regulation from their inception.[76]

The Proposed Rule, by its terms, would only affect a subset of generators. And under FirstEnergy's proposal, RSR Units would continue, as they do today, to bid into and be dispatched by the day-ahead and real-time energy markets. Further, as explained in Part I herein, payments to RSR Units could go to zero, or perhaps even go negative, once the RTOs/ISOs take

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[74] *Pub. Serv. Co. of N.M. v. FERC*, 653 F.2d 681, 683 (D.C. Cir. 1981); Order No. 831, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157 FERC ¶ 61,115 at P 4 (2016) (stating that the Commission's price formation proceedings have the goal of, among other things, "ensur[ing] that all suppliers have an opportunity to recover their costs"); *AEP Power Mktg., Inc.*, 108 FERC ¶ 61,026 at P 152 (2004) ("[O]ur ratemaking policy is designed to provide for recovery of prudently incurred costs plus a reasonable return on investment.").

[75] PJM Comments at 27.

[76] For example, according to the Organization of MISO States, 90% of load in the MISO region is served by traditionally regulated utilities. Org. of MISO States Comments at 4. In PJM, nearly 30% of the capacity is provided by suppliers who fully or partially operate under a traditional model of utility regulation. PSEG Cos. Comments at 23. The Commission also has regulatory authority over a vast amount of generation that operates under cost-of-service regulation in areas outside the RTOs/ISOs. Even within the RTOs/ISOs, auction mechanisms supplement bilateral contracting.

steps to properly compensate resilient generators. Cost-of-service regulation for certain generating units is not a novel concept for the Commission or for the RTOs/ISOs, nor does it pose a threat to the existence or stability of the RTO/ISO markets.

B. The Proposed Rule Is a Proper Exercise of the Commission's Authority Under the FPA

The Proposed Rule is a proper exercise of the Commission's authority under FPA Sections 205 and 206.[77] The Commission's record supports a finding that current rates being paid to resilient generators are unjust and unreasonable because they fail to compensate those generators for the full value they provide to the grid and consumers, and because they have led and will lead to retirements that would not occur if the RTO/ISO markets were functioning properly.[78] FirstEnergy is not alone in this view.[79] The record also supports a finding that the Proposed Rule would establish just and reasonable rates by ensuring resilient generators have the opportunity for cost recovery. There is nothing unlawful or even unusual about the tariff rates in the Proposed Rule—as the Supreme Court has held, "[r]ates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and to compensate its investors for the risks assumed certainly cannot be condemned as invalid."[80]

Contrary to some Commenters' suggestions, the Proposed Rule need not fix *every* resilience-related issue in the electricity sector in order to be proper under Section 206.[81] Indeed, this proceeding need not address complicated natural gas supply issues that create resilience risks

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[77] *See* FirstEnergy Comments §§ III.A-C.

[78] *Id*. § III.A.

[79] *See, e.g.*, Exelon Corp. Comments at 16-20; PSEG Cos. Comments at 22-23, 29.

[80] *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 605 (1944).

[81] *See, e.g.*, ISO New England Comments at 9 (opposing the Proposed Rule because it "does not solve New England's fuel security constraints related to availability of natural gas for generators in winter conditions").

specific to *gas-fired* generators. Those are complicated issues that the Commission *should* address in a separate rulemaking proceeding regarding fuel-*insecure* generation.[82] This rulemaking proceeding, in contrast, is focused on ensuring the grid retains the resilience attributes that can only be provided by fuel-*secure* generators. In light of the current under-compensation of fuel-secure generation units, the Commission must set rates for those units that are just and reasonable.[83]

The Proposed Rule is also not "unduly discriminatory," as some Commenters claim.[84] Undue discrimination for purposes of the FPA consists of an unfair ability of a supplier to charge excessive rates to particular purchasers, for example by providing preferential subsidies to a corporate affiliate. The Commission need not treat all types of electric generating resources equally, but may "reasonably distinguish[] between resource types"[85] when those resources are not similarly situated.[86] More generally, "differences in rates" are not discriminatory when they

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[82] For example, ISO New England highlights the ongoing, unsolved fuel security constraints that its region faces in the winter. *Id*. at 9. These are serious concerns that the Commission and many state commissions have not properly addressed. And many of the merchant generators who oppose action here are the same entities that have steadfastly refused to enter into contracts for firm natural gas pipeline capacity. FirstEnergy encourages the Commission to address these issues. The Proposed Rule will prevent the retirement of fuel-secure generation that currently provides the resilience that insures against the risks that overreliance on natural gas generation and vulnerable gas infrastructure currently pose to New England consumers. It is thus prudent to enact the Proposed Rule while the Commission considers other appropriate measures related to natural gas generation and supply. *See* PSEG Cos. Comments at 12-16.

[83] 16 U.S.C. § 824e(a).

[84] *See, e.g.*, Am. Municipal Power Inc. Comments at 20 (claiming that Proposed Rule is "unduly discriminatory" because it is applicable to a "a limited class of generators"); Attorneys General of Mass. et al. Comments at 7 (arguing that the Proposed Rule would "unduly discriminate" by favoring coal and nuclear generators "over other resources that could provide similar or superior system services or attributes at a lower cost").

[85] *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61157 at P 51 (2016)

[86] *See BP Energy Co. v. FERC*, 828 F.3d 959, 967 (D.C. Cir. 2016) ("No undue discrimination exists where there is 'a rational basis for treating [two entities] differently' and such differential treatment is 'based on relevant, significant facts which are explained.'") (quoting *Complex Consol. Edison Co. of N.Y., Inc. v. FERC*, 165 F.3d 992, 1012-13 (D.C. Cir. 1999)).

are "based upon factual differences,"[87] which can include differences in "cost[s] of service,"[88] and differences in the product ultimately delivered to consumers. That is the case here. Not only do fuel-secure resilient generators have different costs than other generators, they also provide different services—namely, resiliency services—to customers. Accordingly, any claims of undue discrimination are belied by the simple fact that generators lacking on-site fuel do not and cannot provide the same resilience value to the grid as generators with on-site fuel, and are thus not similarly situated for the purposes of a rulemaking about resilience.[89] The Proposed Rule targets an attribute of generation that provides resilience value to the grid, not particular generators or particular fuel types. Because these "factual differences . . . justify . . . differences among the rates," there is no undue discrimination.[90]

C. Ensuring Just and Reasonable Rates Is Within the Commission's Jurisdiction, Not State Jurisdiction

Several Commenters express concern that the Proposed Rule could conflict with state policies regarding utility integration and/or ratemaking.[91] These concerns are misplaced—the

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87 *Portland Gen. Exch., Inc.*, 51 FERC ¶ 61,108, at p. 61,245 n.62 (1990) ("[D]ifferences in rates must be based upon factual differences, for instance, in a utility's cost of service" which would not "violate section 205(b) of the FPA"); *TransCanada Pipelines Ltd. v. FERC*, 878 F.2d 401, 413 (D.C. Cir. 1989) (differences in rates that are "based on relevant, significant facts" are not contrary to the Natural Gas Act and are not arbitrary and capricious); *St. Michaels Utils. Comm'n v. Fed. Power Comm'n*, 377 F.2d 912, 915 (4th Cir. 1967) ("[D]ifferences in rates are justified where they are predicated upon differences in facts . . . .").

88 *Portland Gen. Exch., Inc.*, 51 FERC ¶ 61,108, at p. 61,245 n.62.

89 *See BP Energy Co.*, 828 F.3d at 967. Commenters suggesting that the Proposed Rule is improper fail to provide any meaningful support for their premise that gas-fired and renewable generators somehow provide equivalent resilience to the grid despite their lack of on-site, secure fuel supplies. *See, e.g.*, Attorneys General of Mass. et al. Comments at 7 (arguing that the Proposed Rule would "unduly discriminate" by favoring coal and nuclear generators "over other resources that could provide similar or superior system services or attributes at a lower cost"); Interstate Nat. Gas Ass'n of Am. Comments at 3, 20-21 (claiming that the Proposed Rule is unduly discriminatory because natural gas is "similarly situated" to coal and nuclear with respect to "most products and services they are capable of offering").

90 *St. Michaels Utils.*, 377 F.2d at 915.

91 *See, e.g.*, Pennsylvania Pub. Utils. Comm'n Comments at 25-26; (arguing that the Proposed Rule "may conflict with state jurisdiction over retail ratemaking"); Nat'l Ass'n of Regulatory Util. Comm'rs Comments at 2 (arguing that the Proposed Rule "could affect" state jurisdiction "over generation facilities"); Cal. Pub. Util.

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Commission has exclusive jurisdiction over the rates for wholesale sales of electric energy in interstate power, regardless of how a utility selling wholesale power on the interstate electric grid is currently being or has previously been regulated by its state public utility commission.[92]

States cannot interfere with the Commission's ratemaking decisions, and indeed the Constitution and the Federal Power Act prohibit them from imposing their policy preferences to set rates for generators selling energy in *interstate* markets.[93] In particular, the States cannot insist that the Commission continue to use market-based rates when the Commission finds that those rates are unjust and unreasonable, and therefore unlawful.[94] The Commission alone is empowered with setting just and reasonable rates for wholesale sales, and any "conflict" raised by the States is based on a mischaracterization of the constitutional delineation of state and federal authority over the electricity sector. To be sure, there are state actions that can lawfully be taken. But those actions can lawfully co-exist with what FirstEnergy is proposing here.

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Comm'n Comments at 55 (arguing that the Proposed Rule may interfere with California's long-term electricity planning process); Org. of MISO States Comments at 16. *See also* S. Cal. Edison Co. & S.D. Gas & Elec. Co. Comments at 2 (stating that a nationwide policy on resilient generators "would not be appropriate" due to "California's state policies").

92 *See, e.g.*, *New York v. FERC*, 535 U.S. 1, 21-22 (2002) (describing the Commission's exclusive jurisdiction and the limited authority of the States).

93 *Id.*; *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 1291-92 (2016) (holding that Maryland law affecting interstate rates was preempted by the FPA); *id.* at 1299 ("States interfere with [the Commission's] authority by disregarding interstate wholesale rates [the Commission] has deemed just and reasonable, even when States exercise their traditional authority over retail rates or, as here, in-state generation."); *see also FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 776 (2016) ("When [the Commission] sets a wholesale rate, when it changes wholesale market rules, when it allocates electricity as between wholesale purchasers—in short, when it takes virtually any action respecting wholesale transactions—it has some effect, in either the short or the long term, on retail rates. That is of no legal consequence.").

94 16 U.S.C. § 824d(a) (stating that any rate "that is not just and reasonable is hereby declared to be unlawful"); *id.* § 824e(a) (stating that when the Commission finds that "any rate" is unjust and unreasonable, the Commission "shall determine the just and reasonable rate . . . and shall fix the same by order"); *see also Cent. Vt. Pub. Serv. Corp.*, 84 FERC ¶ 61,194, at pp. 61,973-75 (1998) (describing the Narragansett doctrine, under which States may not use their jurisdiction over retail rates to interfere with wholesale rates set by the Commission under Sections 205 and 206 of the FPA).

V. Opponents' Cost Estimates for the Proposed Rule Are Greatly Exaggerated

Rather than grapple with the risks to the electricity grid posed by the retirement of resilient generators and the costs of replacing the resilience value they provide, several Commenters simply contend that the cost of the Proposed Rule will be enormously high.[95] These estimates, however, are based on dubious assumptions and are not grounded in a realistic view of how the Proposed Rule can be implemented. In reality, the costs of the Proposed Rule are only those necessary to maintain grid resiliency through the preservation of fuel-secure generation. Further, the economic costs of inaction are high. Retiring generation capacity will need to be replaced with costly new generation and new fuel supply infrastructure which still will not have the same resilience qualities as the retiring generation. Additionally, the losses of businesses and tax revenue to local communities due to impending retirements of resilient generation will be substantial. And if and when a resiliency event occurs, there will be substantial adverse economic impacts to the Nation and consumers as a result of blackouts and grid instability.

A. Opponents' Cost Estimates Are Nonsensical

Opponents of the Proposed Rule have put forward wildly inflated projections of its costs. In particular, the PJM Independent Market Monitor's estimate that the Proposed Rule will cost $288 billion over the next ten years is deeply flawed.[96] As explained by Dr. Hunger, the PJM Independent Market Monitor uses a generic approach rather than a unit-specific methodology to estimate the costs of the Proposed Rule, thus distancing itself from the reality of how the

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[95] APPA Comments at 13; Indep. Mkt. Monitor for PJM Comments at 2-8; PJM Power Providers Grp. Comments at 6-7; Potomac Economics at 16; Richard J. Pierce Comments at 4-5.

[96] In addition to the analysis provided by the PJM Market Monitor, FirstEnergy has reviewed the analyses provided in the comments submitted by the Public Utilities Commission of Ohio, the Ohio Consumers' Counsel, the Advanced, Renewable and Storage Energy Industry Associations, the MISO Transmission Owners, the Retail Energy Supply Association, and the Joint Industry Commenters, and found that no party has provided a cost estimate based on a reasonable methodology.

Proposed Rule would actually be implemented.[97] It then "uses a proxy calculation based on the [PJM Independent Market Monitor's] estimation of generator replacement costs," even though neither the Proposed Rule nor any party to these proceedings has suggested that resilience compensation be based on replacement costs.[98] In other words, the PJM Independent Market Monitor has chosen to estimate the cost of something that "is not based on any actual proposals before the Commission in this proceeding."[99]

Moreover, as Dr. Hunger explains, the use of proxies, like those used by the PJM Independent Market Monitor as the basis of its calculations, is "rarely a path to accurate estimation."[100] Nonetheless, the PJM Independent Market Monitor applies a "plethora of other assumptions" without any description or explanation, making it impossible to determine what methodology the company actually used.[101] This produces a "meaningless" range of values between $3 and $32 billion for 2016, an order of magnitude of imprecision.[102] In short, the PJM Independent Market Monitor's flawed and opaque process of measuring the Proposed Rule, using a compensation method that neither the Secretary of Energy nor anyone else actually supports, results in a "spread of estimated costs [that] is so broad as to be useless."[103]

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97 Hunger Reply Aff. at 6-7.

98 *Id*. at 6. This said, even if the PJM IMM's cost estimates have any validity—and they do not—they show how much it might cost to put in place new, replacement generation if existing fuel-secure resources are forced to retire prematurely.

99 *Id.*

100 *Id.* at 6-7.

101 *Id.* at 6.

102 *Id.* at 3.

103 *Id.* at 7.

B. The Proposed Rule's Actual Costs Are Limited to the Retention Costs of Resilient Units

In reality, the actual costs of the Proposed Rule will be limited. The Proposed Rule applies only to a subset of generators, and if properly implemented would create only the additional payments needed to ensure that resilient generators recover their costs as they would if the energy and capacity markets took into account the value of fuel security to the grid—that is, if the markets were properly functioning and delivering economic outcomes.

The Proposed Rule will not result in any double compensation for resilient generators or double payments by consumers, and nothing in the text of the Proposed Rule suggests that it would. FirstEnergy's proposal for tariff modifications and RSR Agreements will increase payments to resilient generators only to the extent the markets do not currently value resilience.[104] The recovery of costs by resilient generators under the Proposed Rule thus pays for costs and a reasonable rate of return.[105]

Moreover, the costs of the Proposed Rule are self-limiting and will decrease if market reforms are made to properly value resiliency. As described in Part I, payments by RTOs/ISOs

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[104] FirstEnergy Comments, Ex. 7 (McMahon Aff.) at 4 (discussing how market payments to RSR Units will be netted against the Monthly RSR Amount).

[105] The Proposed Rule states that the compensable costs paid to resilient generators should include a "fair return on equity." Proposed Rule § 35.28(g)(10)(iii) & (iv). Mr. McMahon states that, for such purposes, "[t]he Return on Equity can be calculated consistent with the approach used in traditional cost-of-service ratemaking, based on a return-on-equity percentage and capital structure." FirstEnergy Comments, Ex. 7 (McMahon Aff.) at 10. One Commenter suggests that the return on equity ("ROE") should be "in the 2%-4% range" because this is "the minimum necessary to ensure that the fuel secure generation does not retire prematurely." Ky. Indus. Util. Custs. Inc. Comments at 5. FirstEnergy submits that an ROE in this range would not only not prevent generation from retiring, but would also be contrary to the Commission's long-standing practice of setting ROEs based on a discounted cash flow ("DCF") analysis of a proxy group of companies. There, the Commission's process removes from the proxy group as an outlier any observation with an implied ROE less than 100 basis points above the cost of debt (usually assumed to be the six-month average current bond yields for public utilities). *See, e.g.*, *S. Calif. Edison Co.*, 131 FERC ¶ 61,020 at PP 54-56 (2010). Presently, this yield is about 4%. An ROE of 2% to 4% is not only well below any ROE that would be established by the Commission's DCF proxy group methodology, but is so low that it would be excluded from the proxy group in the first instance. This Commenter's request for an ROE at this level is completely contrary to Commission precedent and should be summarily rejected.

to RSR Units would go to zero if and when the RTOs/ISOs take action to correct distortions in their markets and properly value fuel security and resiliency. In fact, under FirstEnergy's proposed RSR Agreement payments could actually go negative if the market compensates RSR Units over and above the costs needed to remain in operation. Indeed, the costs of the Proposed Rule are likely to decrease over time as the RTOs/ISOs begin to make progress on incorporating the value of resilience into their price formation mechanisms.

C. The Costs of Inaction Are High

The economic and social costs of failing to take action to remedy the unjust and unreasonable rates being paid to fuel-secure resilient generators are high. Many local governments, businesses, and unions support the Proposed Rule because of its economic benefits to local communities. These Commenters stress the importance of fuel-secure generators to the economic vitality of communities across the United States.[106] FirstEnergy agrees.

In addition, the lost generation capacity will result in higher market energy prices in the near term because RTOs/ISOs will need to dispatch "higher up the stack" in order for supply to meet demand. And in the longer term, the lost generation will need to be replaced with new natural gas-fired generation as well as new gas pipeline infrastructure to supply the new

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[106] *See, e.g.*, Building Laborers' Union, Local No. 310 Comments at 2-3; Indus. Terminal & Salvage Co. Comments at 3; Penn-Northwest Development Corp. Comments at 3; W.V. Coal Comm'n Comments at 4-5; Colonial Chemical Co. Comments at 3; Ingram Barge Co. Comments at 3; Minnotte Contracting Corp. Comments at 3; Colona Transfer, LP Comments at 3; DeNoxDirect, LLC Comments at 3; Sorbet Injection Specialist, LLC Comments at 3; Penn-Northwest Development Corp. Comments at 3; Building Laborers' Union, Local No. 310 Comments at 3; Burnam Industrial Contractors Comments at 3; Camelot Coal Co. Comments at 3; FreightCar Am., Inc. Comments at 3; IBEW Local 272 Comments at 3; IBEW Local 245 Comments at 3; IBEW Local 1289 Comments at 3; IBEW Local 1413 Comments at 3; IBEW Local 29 Comments at 3; IBEW Local 246 Comments at 3; United Way of Jefferson Cty. Comments at 3; United Way of Beaver Cty. Comments at 3; Lhoist North America, Inc. Comments at 3; Campbell Transp. Co. Comments at 3; Ottawa Cty. Improvement Corp. Comments at 3; South Side Area Sch. Dist. Comments at 3; Util. Workers Union of Am., Local 350 Comments at 3; Util. Workers Union of Am., Local 457 Comments at 3; Delegate Brett Wilson, Md. Gen. Assembly Comments at 3; J and J Equip. Co. Comments at 3; Upper Ohio Valley Building and Construction Trades Council Comments at 3.

generation. As explained in the attached Reply Affidavit of Michael A. Rutkowski of Navigant Consulting, the increases in energy market costs in PJM alone will increase capacity and energy market costs by $90 billion over the next 15 years.[107]

Mr. Rutkowski modeled the effects of a failure to implement the Proposed Rule by comparing energy and capacity costs in a PJM "Base Case Scenario" to costs in an "Early Retirement Scenario" in which (1) merchant nuclear and coal-fired power plants in the Eastern Interconnect that are not currently slated for retirement end up retiring due to a lack of just and reasonable compensation resulting from the Proposed Rule not being in place,[108] (2) the resulting impact in PJM alone is that additional natural gas combined cycle generators are built to compensate for the loss of 29 GW of nuclear capacity and 37.6 GW of coal-fired capacity,[109] and (3) there is a "significant expansion of natural gas pipeline infrastructure" to supply those new plants—in total, over 6,200 miles of pipeline that will cost an additional $25 billion over 13 years.[110]

Mr. Rutkowski simulated the effects of these changes in resource mix on PJM's energy and capacity markets between 2018 and 2032.[111] In the PJM capacity markets alone, the cost of additional new generation and the associated new pipeline infrastructure raises total capacity costs over the base case by $48 billion over 15 years.[112] Prices in the PJM electric energy markets also rise because the replacement of nuclear and coal-fired generators with low marginal costs by natural gas-fired generators with higher marginal costs increases locational marginal

107 Rutkowski Reply Aff. ¶ 9.

108 *Id.* ¶¶ 10, 18-20.

109 *Id.* ¶¶ 7, 18-20, 25.

110 *Id.* ¶¶ 8, 25.

111 *Id.* ¶¶ 10-13.

112 *Id.* ¶ 8.

prices and total energy costs across PJM.[113] Further, that increase "will be exacerbated by higher natural gas commodity costs due to the higher demand for natural gas caused by these new [generators]."[114] Mr. Rutkowski's model predicts that the increase in energy costs in PJM will be $42 billion over 15 years.[115] Combined, the model predicts that total increases in energy and capacity costs in PJM if the Proposed Rule is not implemented will be $90 billion over 15 years.[116]

Moreover, retirements due to current rates, if left unchecked, will result in the *permanent* loss of the value of fuel security to the electric grid. If fuel-secure generation is instead replaced with natural gas and renewable generators, which do not have access to on-site, secure fuel supplies, there will be a need for significant redundancies in the number of new generating units, transmission lines, and gas pipelines in order to maintain the grid's current level of resilience. A single 500 MW gas-fired unit is not as resilient as a single 500 MW coal-fired unit; an equivalent system with a non-diverse fuel mix would consist of more than one gas-fired unit, each supplied by different pipelines. In other words, it will take more than a megawatt-for-megawatt replacement of nuclear and coal-fired units with gas-fired units to maintain the grid's resilience. The failure to value resilience in the current markets thus gives a false impression of the costs of replacing retiring fuel-secure generators—costs that will ultimately be paid by consumers. Thus, Mr. Rutkowski's estimate that the new gas-fired generation and supply infrastructure required to simply replace retiring capacity will cost $90 billion[117] is actually a conservative *under*estimate,

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113 *Id.* ¶ 7.

114 *Id.* There are also additional costs due to increased transmission congestion. *Id.*

115 *Id.*

116 *Id.* ¶ 9.

117 *Id.* ¶¶ 6, 9, 28.

because it does not factor the cost of implementing replacement technologies for fuel-secure, resilient nuclear and coal-fired generation.[118] The additional plants and pipelines, as well as transmission infrastructure, that would be necessary to replace the lost value of resilience that nuclear and coal-fired plants provide to the grid would raise costs even further than those calculated in Mr. Rutkowski's estimate.

Further, in the near term, retirement of fuel-secure generation will leave consumers vulnerable to the costs and safety risks of a system that is increasingly dependent on vulnerable natural gas supply systems. Dr. Lawrence Makovich estimates that a Polar Vortex-like event occurring today, in a PJM system that is less fuel diverse than in 2014, would result in a five-hour power outage of an average of 1,400 MW, at a cost of $1.2 billion.[119] Under the PJM supply portfolio as it would exist if two additional nuclear units, Perry and Davis Besse, retire, there would be a nine-hour outage of an average of 2,400 MW of power, at a cost of $3.7 billion. This analysis, of course, fails to account for the possibility of more extreme events that could affect fuel supplies, such as terrorist and cyberattacks,[120] and only deals with what might happen during a single storm in a single year. Similarly, Mr. Rutkowski opines that the replacement of nuclear and coal-fired units with gas-fired generation if the Proposed Rule is not implemented would "over-weight[] the reliance on fuel-insecure natural gas-fired generation and reduce[] the diversification of the PJM generation portfolio, thereby decreasing the resilience of the bulk electric system during disruptive events or conditions."[121] In the future, as Dr. Hunger explains,

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118 If taken at face value, the PJM Independent Market Monitor's estimate of as much as $288 billion of replacement costs for resilient nuclear and coal-fired units in the PJM region suggests that retaining existing resilient nuclear and coal-fired units avoids considerable expense to replace the units in kind.

119 PSEG Cos. Comments at 9.

120 *See id.*

121 Rutkowski Reply Aff. ¶ 9.

"extreme events should be expected to strain the grid, and it is not feasible at this time to know which resources will be needed, and which will not."[122] Implementing the Proposed Rule would ensure that fuel-secure resilient generators are still available in those scenarios; failing to implement the Proposed Rule would guarantee that they are not available, regardless of what threats and conditions emerge.[123]

Finally, opponents of the Proposed Rule are only able to paint a rosy picture of the economics under a less-diverse grid by using estimates of low and stable energy prices based on assumptions about the price of natural gas that may not hold. If fuel-secure resilient generators are lost to the grid and natural gas prices rise (which they inevitably will), consumers will have no choice but to pay higher costs for an electric system that is less resilient.

VI. FirstEnergy Agrees with the PSEG Companies that the Commission Should Clarify that Generators that Routinely Provide Any of the Ancillary Services Listed in the Proposed Rule Will Remain Eligible

As the PSEG Companies correctly point out in their Comments,[124] the Commission should clarify that eligible resources will not be required to supply the listed ancillary services at all times.[125] If this were to be the case, then no nuclear plants would qualify under the Proposed Rule, as many of the ancillary services listed can only be provided by these plants when they are not providing electricity to the grid. This, of course, would defeat the purpose of the Proposed Rule in the first place (*i.e.*, providing financial support to fuel-secure generation). Instead, the Commission should clarify that resources that are able to provide ancillary services when called

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122 Hunger Reply Aff. at 10.

123 *See id.* at 10-11.

124 PSEG Cos. Comments at 19-20.

125 FirstEnergy did not address this issue in its initial comments as it had thought that this interpretation was self-evident. However, after reviewing the PSEG Companies' comments, FirstEnergy wishes to note that it agrees with PSEG's interpretation.

upon to do so or that routinely provide *any* of these ancillary services meet the eligibility requirements under the Proposed Rule.

VII. Conclusion

For the reasons discussed above, the Commission should find that the current RTO/ISO markets are unjust and unreasonable because they fail to compensate generators for the critical resiliency attributes that they provide to the electric grid. In addition, the Commission should adopt the Proposed Rule, subject to the modifications described in Part IV of FirstEnergy's Comments, and direct that subject RTOs/ISOs adopt the proposed RSR tariff provisions and associated RSR Agreement (subject to limited changes "consistent with or superior to" the proposed tariff provisions and agreement). As noted above, time is of the essence in order to prevent additional premature retirements of fuel-secure generation resources and the resulting increases in costs to consumers. Therefore, the Commission should act promptly to adopt a final rule by no later than December 11, 2017, and order the RTOs to act promptly within the timeframe described in the Department of Energy's Notice so that the benefits of fuel-secure generation can be preserved to ensure a resilient grid now and into the future. Such action will result in just and reasonable rates and preserve critical resources at premature risk of retirement due to market deficiencies.

Respectfully submitted,

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Counsel for FirstEnergy Service Company and its named affiliates

Dated: November 7, 2017

INDEX OF REPLY EXHIBITS

No.	Item
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2	Reply Affidavit of Michael A. Rutkowksi
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4	N. AM. ELEC. RELIABILITY CORP., STATE OF RELIABILITY 2017 (June 2017)
5	N. AM. ELEC. RELIABILITY CORP., ERO RELIABILITY RISK PRIORITIES: RISC RECOMMENDATIONS TO THE NERC BOARD OF TRUSTEES (Nov. 2016)

Exhibit 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)))	Docket No. RM18-1-000

AFFIDAVIT OF
DR. DAVID HUNGER
ON BEHALF OF
FIRSTENERGY SERVICE COMPANY
IN RESPONSE TO INITIAL COMMENTS

I. INTRODUCTION

Q: Please state your name, occupation, and business address.

A: My name is David Hunger. I am a Vice President within the Energy Practice of Charles River Associates ("CRA"). My address is 1201 F St. NW, Suite 800, Washington, DC.

Q: What is your education and professional background?

A: I am experienced in energy market analysis, and was formerly a senior economist at the Federal Energy Regulatory Commission ("Commission"). For 14 years at the Commission, I led or participated in analyses involving mergers and other corporate transactions, market power in market-based rates cases, affiliate transactions, investigations of market manipulation in electricity and natural gas markets, demand response compensation, compliance cases for capacity and energy market rules in Regional Transmission Organizations ("RTOs"), and competition issues in electricity markets. Since leaving the Commission and joining CRA in June 2013, I have testified in numerous proceedings involving market power and market design in the organized markets administered by Independent System Operators ("ISOs") and RTOs. I have submitted testimony on energy-related matters before FERC, State Public Utility Commissions, Federal Court, and an Arbitration Tribunal.

I hold a B.A. in Mathematics from the University of Massachusetts and an M.S. and a Ph.D. in economics from the University of Oregon. My experience, education, and prior testimony are described in my *curriculum vitae*, which was attached to my initial Affidavit submitted in this proceeding on October 23, 2017 on behalf of FirstEnergy Service Company ("Initial Affidavit").

Q: What is the purpose of this affidavit?

A: In my Initial Affidavit, I provided economic and regulatory context supporting the Commission's Proposed Rule to provide cost-based compensation to resources that provide resilience services to the electric grid. The Commission received copious input on the Proposed Rule from interested parties of all types, both in support of and arguing against the Proposed Rule. In this affidavit, I provide observations regarding some of the comments and, in particular, the initial comments of the Independent Market Monitor ("IMM") for PJM Interconnection, L.L.C. ("PJM"). More specifically, I address in this Affidavit both the PJM IMM's estimation of the customer costs of complying with the Proposed Rule in PJM, where FirstEnergy's assets are located, and the PJM IMM's statements regarding the fact that PJM's market provides economically efficient provision of electricity services and provides efficient signals for investment.

Q: How did FirstEnergy recommend the Commission implement the Proposed Rule?

A: FirstEnergy, in its initial Comments filed on October 23, 2017, recommended that the Commission require RTOs/ISOs to adopt specific proposed *pro forma* tariff provisions and a Resiliency Support Resource ("RSR") agreement that would serve as mechanism for the implementation of the Proposed Rule by providing cost-based compensation for fuel-secure, resilient generation resources. The proposed RSR agreement would provide for a qualifying unit to receive monthly payments sufficient to cover its fully allocated costs of operation and service and a fair return on equity. This amount would be net of any revenues for capacity, energy, and ancillary services provided from the RTO/ISO market, thereby ensuring that resources are not able to "double dip" from both cost-based and market-based revenue streams. The RSR agreement would be executed between the RTO/ISO and the owner of the RSR unit and filed with the Commission.

Q: Please summarize your conclusions.

A: In preparing this affidavit, I have reviewed the responses of numerous commenters in this proceeding, with a focus on the comments of the PJM IMM that presents a number of quantitative analyses. The PJM IMM also makes assertions as to the current functioning of the PJM market and its ability to send efficient price signals that lead to cost effective levels of long term investment. As I describe further below, I have come to the following conclusions:

- The PJM IMM's cost estimates are just that, estimates, and are not reliable and are unreasonable. The methodology has no basis in the Proposed Rule. Instead, the IMM relies on an inappropriate cost proxy that results in an extremely broad range of possible costs, so much so that the results are meaningless. Moreover, the PJM IMM fails to address the cost increases that occur when resilient generation is retired and new transmission must be built in order to maintain the same level of reliability, without even addressing resiliency.

- The PJM IMM avers that PJM's markets provide efficient signals for provision of electric service and retirement decisions. I disagree, particularly in light of the substance of this proceeding. Rather, in my view, PJM's markets fail to price a particular valuable service that is provided to the system—namely, resilience—and therefore cannot possibly provide fully efficient signals to generator operators and investors.
- Finally, I reiterate my concerns regarding the fuel security requirements of PJM's Capacity Performance ("CP") construct that I have previously expressed to the Commission during its consideration of the PJM CP proposal; specifically, the PJM CP construct does not adequately compensate resilient resources for the resiliency value they provide because there are no firm fuel eligibility criteria.

Q: How is this affidavit organized?

A: Following this introduction, Section II addresses the PJM IMM's estimate of customer costs in the PJM footprint associated with the Proposed Rule. Section III discusses whether or not the PJM markets provide price signals that support efficient long-term decision-making in generation investment. Section IV concludes my affidavit.

II. ESTIMATES OF CUSTOMER COST OF PROPOSED RULE

Q: What does the PJM IMM state regarding the cost of the Proposed Rule?

A: The IMM states that it has "estimated the cost of implementing the [Proposed Rule] using a range of assumptions so that the cost of each option can be considered by the Commission."[1]

[1] Comments of the Independent Market Monitor for PJM, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 at 4 (Oct. 23, 2017) ("PJM IMM Comments") (citing MONITORING ANALYTICS, LLC, STATE OF THE MARKET REPORT FOR PJM (2016) VOLUME 2: DETAILED ANALYSIS 297 tbl.7-24 (Mar. 9, 2017) ("PJM State of the Market Report 2016")).

For the year 2016, for example, at 100 percent "replacement value," the IMM suggests that the Proposed Rule would increase costs to PJM customers by $32 billion.[2] At 50 percent "replacement value," this number would be $13 billion and, at 25 percent, $3 billion.[3] Across a longer period, the IMM calculates that the Proposed Rule would result in 10-year incremental customer costs of $18 billion, $97 billion, and $288 billon for 25 percent, 50 percent, and 100 percent of replacement cost, respectively.[4] I note that the IMM's high and low estimates differ by $271 *billion*, and the high end estimate is 1,694 percent of the low end estimate. The range of these estimates alone call into question their validity and the underlying assumptions upon which they are based. In my judgment, the Commission cannot rely on such unreliable estimates.

Q: What methodology does the PJM IMM employ to arrive at its estimates?

A: The IMM's approach is based on the assumption that the Commission's Final Rule, as implemented by the RTOs/ISOs, would apply a generic approach to compensating generators rather than use a unit-specific methodology. To make its calculations, the IMM first identified coal and nuclear units in the PJM footprint not subject to cost-of-service regulation. The IMM then calculated the customer costs of the Proposed Rule, on a 20-year levelized basis, making the major assumption that the amounts paid to compensated units would be based on the replacement cost of each unit. This approach was repeated at 100 percent, 50 percent, and 25 percent of replacement cost. The IMM

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[2] *Id*. at 5. I understand the implication of this "replacement value" analysis to be that resilient coal and nuclear units receiving cost-based compensation for resilience would set their required compensation levels (effectively their rate base) at the cost of replacement, or some fraction thereof.

[3] *Id*. at 6.

[4] *Id*. at 7.

references in its analysis the PJM 2016 State of the Market Report,[5] which implies that the IMM has subtracted from the total "replacement value" figures any forecasted energy, ancillary services, and capacity revenue, as was stated in the 2016 State of the Market Report for PJM.[6] The IMM concludes that what remains is the net revenue requirement necessary to develop such units on a 20-year levelized basis.[7] However, the IMM's explanation lacks much detail as to its methodology, so it is difficult to know for sure. Likewise, a description of the plethora of other assumptions or workpapers necessary to make such a calculation are also missing from the IMM's comments. In my judgment, the Commission cannot rely on this analysis.

Q: What is your assessment of the PJM IMM's methodology for estimating customer costs?

A: I have several concerns regarding the PJM IMM's methodology for estimating customer costs of possible resilience compensation schemes. First, I point out that it uses a proxy calculation based on the IMM's estimation of generator replacement costs. Neither the Proposed Rule nor any party to these proceedings has suggested that resilience compensation be based on replacement cost for coal and nuclear units. Thus, the IMM's reliance on replacement costs in performing this cost estimate is a proxy approach to estimate the consumer expense based on a pre-existing data set held by the IMM but that is not based on any actual proposals before the Commission in this proceeding. Relying on proxies can have value in some instances where information is scarce, but such

[5] *Id*. at 4 (citing PJM State of the Market Report 2016 at 297 tbl.7-24).

[6] PJM State of the Market Report 2016 at 296.

[7] *See* PJM IMM Comments at 5-6 & tbl.5 ("Table 5 shows the difference between the current level of revenues paid to the nuclear and coal units and the level of revenues that would be required if the units were paid at 100 percent of current replacement costs on a 20-year levelized basis.").

approaches are rarely a path to accurate estimation. Their shortcomings in this proceeding are evident in the IMM's results in that the spread of estimated costs is so broad as to be useless. Again, the estimate has a range of more than a quarter trillion dollars with over 1,500 percent variation between the high and low end estimates. Thus, the IMM's proxy should be approached with significant skepticism.

Second, as I state above, the IMM provides little in the way of methodological details or underlying assumptions. Without knowing these things, it is hard to understand how a result was produced and therefore the result is not reliable.

Finally, in addition to the other shortcomings of the IMM's analysis, it does not factor into its calculations other cost increases that will occur, and risks that will be expanded, if resilient units are retired. For example, not only must all retired capacity be replaced, but there is also the cost of new transmission that will need to be developed to ensure reliability as the topology of the system must be changed to accommodate new generators. There is also the economic risk associated with reducing the fuel diversity of the generation mix; the more that natural gas is the primary generation feedstock, the more exposed customers become to the fluctuating cost of natural gas.

Q: Have any other parties provided an analysis of the Proposed Rule that utilizes a reasonable cost-estimate methodology?

A: Not in my opinion.[8]

[8] For the purpose of this statement, I have reviewed the comments submitted by the Public Utilities Commission of Ohio, the Ohio Consumers' Counsel, the Advanced, Renewable and Storage Energy Industry Associations, the MISO Transmission Owners, the Retail Energy Supply Association, and the Joint Industry Commenters.

III. THE PJM MARKET DOES NOT PROVIDE PRICE SIGNALS THAT RESULT IN EFFICIENT LONG-TERM INVESTMENT DECISIONS

Q: What does the PJM IMM assert with respect to the efficacy of investment signals provided by the PJM market?

A: The PJM IMM's conclusion on this topic is evident in its heading to Section D of its comments: "The Evidence from PJM's Markets Shows Efficient, Competitive Provision of Reliable Energy, Including Efficient Signals for Retirement."[9] To support this claim, the IMM presents historical market data for the energy, ancillary services, and capacity markets operated by PJM. This includes a showing that, due to recent market conditions, certain types of generators struggle more to recover avoidable costs from market revenues. The IMM proceeds to reason that units that fail to recover avoidable costs over several years are receiving "a market signal that the unit is uneconomic and at risk of retirement for economic reasons."[10] Without much additional support, the IMM then implies that all of the PJM markets together provide efficient market signals, therefore supporting efficient decisions on the part of generators, including whether or not to retire.[11]

Q: What is your response to the PJM IMM's statements on this topic?

A: I agree with the general sentiment of the PJM IMM's comments: that well-formulated price signals in RTO/ISO markets will support efficient decisions regarding long-term decisions by generator owners, including investment and retirement. However, this sentiment has an important caveat—to achieve the stated objective of providing market

[9] PJM IMM Comments at 15.

[10] *Id.* at 19.

[11] *Id.* at 9.

signals that lead to efficient decisions on the part of market participants, the markets must efficiently price all valuable services provided to the system. In this regard, resilience is an attribute that has clear value to the system, but for which no specific compensation is provided.[12] Therefore, the market does not provide fully efficient price signals and, by definition, *cannot* result in efficient economic entry and exit. The mere presence of entry and exit in a market that does not price all valuable attributes of generation does not indicate *efficient* entry and exit.

In addition to the above, I have two additional observations relating to efficient entry and exit in RTO/ISO markets. First, while the objective of efficient compensation for all provided services would be a strong step towards efficient markets, even if that is achieved there are numerous other elements of RTO/ISO markets that stymie efficient behavior. These include, but are not limited to, energy offer mitigation rules, mismatch between capacity price signals and capacity investment periods, and subsidies provided from outside the market.

Second, as I stated in my Initial Affidavit, recent patterns of generator retirement have been severe, particularly for resilient nuclear and coal-fired units; if these trends continue, it will be problematic. Shortcomings in RTO/ISO market rules, which have been exacerbated by the changing fuel price landscape and the impact of government

[12] Though the statement is oblique, PJM acknowledges as much its comments in this docket: "[T]o the extent the Commission seeks to value the resilience attributes of a resource through a cost-of-service rate, an approach similar to a reliability must run concept, which is in place today, could, under certain limited circumstances under RTO-specific rules, could provide a far more appropriate model." *See* Initial Comments of PJM Interconnection, L.L.C. on the United States Department of Energy Proposed Rule, App. A at 10, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017).

regulations and subsidies, are leading to these accelerated retirements.[13] Implementing the Proposed Rule will ensure the retention of these resilient resources that contribute to reliable grid operation. In the future, extreme events should be expected to strain the grid, and it is not feasible at this time to know which resources will be needed, and which will not. On the other hand, should the current fleet of resilient generators retire, in whole or in part, they will certainly not be available when needed. Thus, action is needed now and until such time when suitable, cost-effective replacement technologies for nuclear and coal-fired generation can be implemented.

Q. Does PJM's existing Capacity Performance market design adequately address fuel security and resiliency?

A. No. PJM's CP construct fails to directly address inadequacies in generator's fuel security arrangements and certainly was not designed to compensate generators for providing resiliency benefits. As the late Dr. Hieronymus and I previously testified in the CP proceeding before the Commission almost three years ago, the PJM CP construct "will not require any threshold demonstration of firm fuel supply arrangements or on-site capability that would indicate an ability to deliver during extreme weather events."[14] As we further explained, the failure to require a demonstration of firm fuel supply arrangements is problematic because "[p]ast auction experience suggests that market participants take an optimistic view of their ability to perform, especially if there is a

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[13] *See* Comments of FirstEnergy Service Company *et al*. in Support of the Grid Reliability and Resilience Pricing Notice of Proposed Rulemaking at Ex. 4 § 3 (Affidavit of David Hunger), *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 23, 2017).

[14] Comments and Limited Protest of the PJM Utilities Coalition at Attach. A ¶ 48 (Affidavit of Dr. William Hieronymus and Dr. David Hunger), *PJM Interconnection, L.L.C.*, Docket No. ER15-623-000 (Jan. 16, 2015).

low-risk opportunity to buy out any obligation later."[15] Consequently, as we predicted, the CP construct has not provided a permanent solution to the capacity market revenue inadequacy problem,[16] as the CP construct has failed to reverse the price suppression seen in the auctions conducted prior to CP implementation.

As I discussed in *Calpine v. PJM*, a competitive sell offer in the CP auction is based on the seller's expected opportunity cost of being a CP resource:

> [CP Resources] face the opportunity cost of being an energy-only resource and the risk of performance penalties, as do all resources, and would be expected to submit their sell offers accordingly. This is where the CP market design has changed the incentives of sellers, because whatever the net position, all sellers face the performance risk/reward decision.[17]

In my opinion, the continued low clearing prices seen in the CP auctions are the result of low expectations of the opportunity cost of being a CP resource (staying out and collecting bonus payments for performing during performance hours). As of yet, there have been no CP events and there is ambiguity regarding the bonus pool. Consequently, sell offers reflect a low opportunity cost and risk premium.

I illustrate the point that CP has failed to reverse the price suppression in the chart below, which was developed using publicly available data from PJM, as well as information from FirstEnergy witness, Michael A. Rutkowski.

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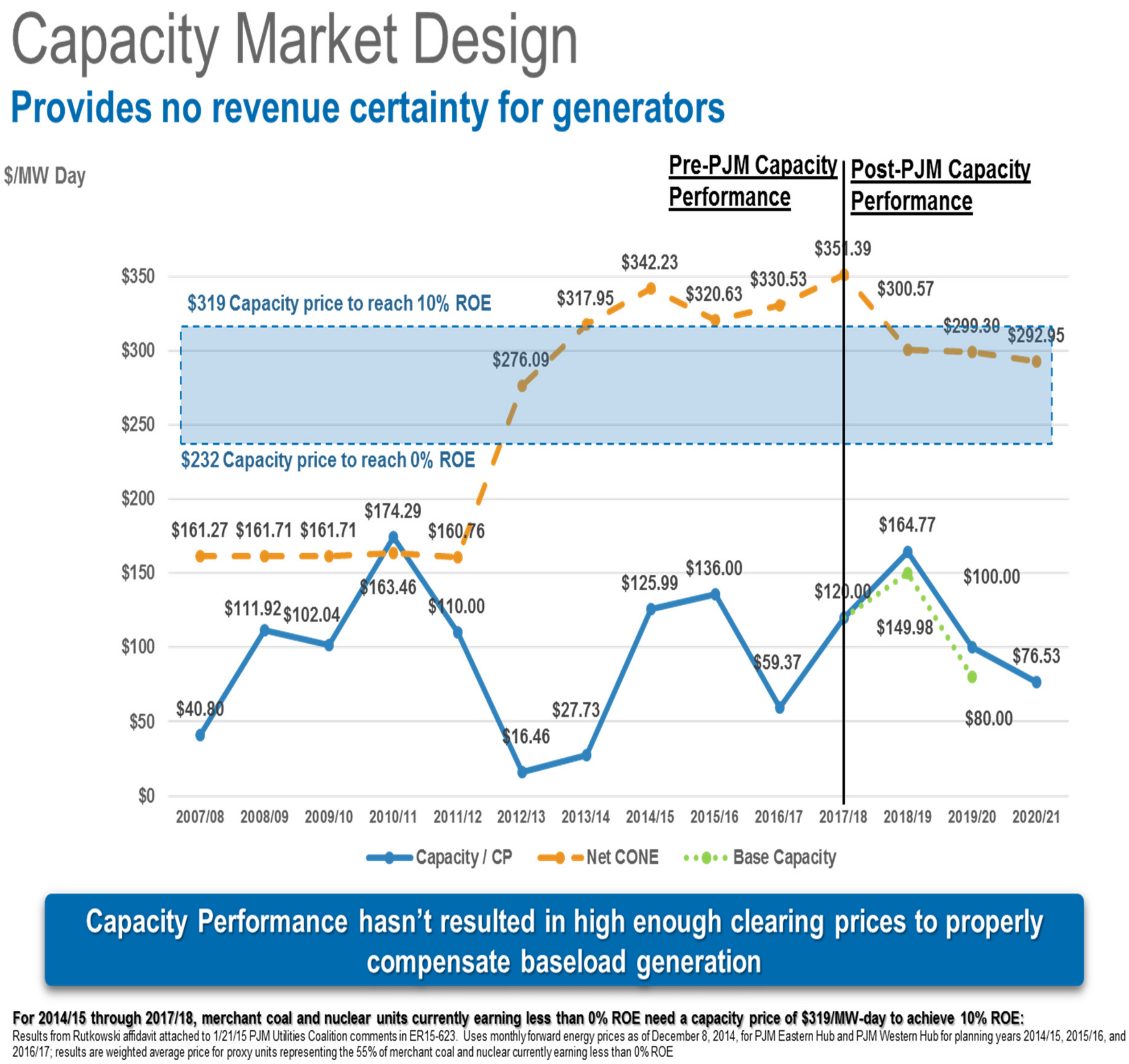
[15] *Id*.

[16] *Id*. ¶ 3.

[17] Protest of FirstEnergy Service Company at Attach. A ¶ 42 (Affidavit of Dr. David Hunger), *Calpine Corporation, et al. v. PJM Interconnection, L.L.C.*, Docket No. EL16-49-000 (Apr. 11, 2016).



IV. CONCLUSIONS

Q: Please summarize your conclusions.

A: This affidavit responds primarily to the PJM IMM's comments in this proceeding and discusses two primary conclusions. First, the IMM's estimate of consumer costs of cost-based compensation for resilient resources is based on an inappropriate proxy that results in an overly broad result that is of no use to the Commission in the present proceeding. Second, the IMM's statements about PJM market signals leading to efficient investment and retirement decisions neglect the fact that PJM's markets do not provide compensation for all valuable services provided and, in particular, fail to provide compensation for resiliency attributes. This failure to compensate resources for resilience leads to a failure to provide fully efficient prices and, as a result, such prices cannot lead to efficient entry and exit decisions.

Q: Does this conclude your affidavit?

A: Yes, it does.

VERIFICATION OF DAVID HUNGER

I, David Hunger, being duly sworn, affirm that the foregoing Reply Affidavit of David Hunger has been prepared by me and/or subject to my direct supervision, and is true and correct to the best of my knowledge, information, and belief.

____
David Hunger

Subscribed and sworn before me this 6 day of November, 2017.

Corlis C. Carter
____
Notary Public

CORLIS C. CARTER
NOTARY PUBLIC
EXP.
-14-2019
CT OF COLUMBIA

CORLIS C. CARTER
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires June 14, 2019

<u>Exhibit 2</u>

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)))	Docket No. RM18-1-000

AFFIDAVIT OF
MICHAEL RUTKOWSKI
ON BEHALF OF
FIRSTENERGY SERVICE COMPANY
IN RESPONSE TO INITIAL COMMENTS

1. My name is Michael A. Rutkowski. I am a Managing Director in the Energy Practice of Navigant Consulting, Inc. My business address is 150 North Riverside Drive, Chicago, Illinois 60606.

2. I am submitting this affidavit on behalf of FirstEnergy Service Company.

<u>Experience and Qualifications</u>

3. I have 28 years of engineering and management consulting experience in the electric power and natural gas industries. Many of my past consulting assignments have focused on improving the financial and operational performance of power generation plants, as influenced by changing wholesale electric market structures and the associated revenue optimization and cost reduction opportunities. Other engagements have included evaluation of fossil power plant pollution control technology investment decisions to meet state and federal environmental mandates; assessment of the financial viability of new proposed power plants in structured wholesale electric markets; and development of power generation portfolio strategies (including development, investment, acquisition, and shutdown decisions). I also spent approximately seven years in the late 1980s and early 1990s working as an engineer in fossil and

nuclear power plants, assisting the owners with maintenance, reliability, and heat rate improvement projects to improve the long-term financial performance of these plants.

4. I have been involved in assessing and analyzing the projected financial performance of power generation plants for over 20 years in Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"), including the PJM Interconnection, LLC ("PJM"); Midcontinent Independent System Operator, Inc. ("MISO"); California Independent System Operator Corp.; the Electric Reliability Council of Texas; and others. I have also provided analytic support to management teams evaluating power plant reliability improvement and maintenance spending decisions to achieve and maintain profitability.

Educational Background

5. I hold a Bachelor of Science degree in Mechanical Engineering from the University of Illinois at Urbana-Champaign and a Master's degree in Management with a concentration in Finance and Strategy from Northwestern University's Kellogg Graduate School. I am also a registered Professional Engineer in the state of Illinois. My experience is summarized in my curriculum vitae, attached hereto.

Summary of Hypothesis and Conclusions

6. I have been asked to analyze the impacts on PJM of merchant nuclear and coal-fired generating unit retirements if a mechanism such as the Grid Resiliency Pricing Rule ("GRPR") proposed in this proceeding is *not* put into place. In short, the retirement of these units will impose significant costs on the PJM grid power system due to the need to construct additional generation and associated infrastructure—$90 billion over the next 15 years.

7. Without the GRPR, merchant nuclear and coal-fired generators in PJM (and elsewhere) may not receive sufficient compensation to maintain profitability, and these units are at risk of rapidly retiring prior to the end of their useful lives (as early as late 2018). In order to replace these units with dispatchable generation, new natural gas-fired combined cycle ("NGCC") units will be developed and constructed, and this will likely occur several years after the retirements (i.e., between 2021 and 2027). The loss of low marginal cost nuclear and coal-fired units in PJM and the associated entry of the NGCCs will result in increased locational marginal prices and total electric energy costs to serve PJM customer load due to the generally higher variable costs of NGCCs. This price effect will be exacerbated by higher natural gas commodity costs due to the higher demand for natural gas caused by these new NGCC units. Some of this electric energy cost increase will also be caused by transmission congestion resulting from potentially sub-optimal locations of the new NGCCs on the transmission grid. We estimate the total increase in electric energy costs to serve PJM load to be approximately $42 billion (in 2016 dollars) over the 15-year period from 2018 to 2032.

8. In addition to the higher energy prices, supplying natural gas fuel to the new NGCC units will require significant expansion of natural gas pipeline infrastructure, which must be paid for by the NGCC owners through contracting firm transportation ("FT") of gas supply capacity from the pipeline owners. The NGCC owners will seek to recover their fixed costs (including capital costs, fixed operating and maintenance costs of the NGCC plant, and the FT component of gas supply costs) through the PJM capacity market, with the net effect being an increase of approximately $48 billion in total capacity costs to ensure resource adequacy in PJM over the 2018 to 2032 period.

9. Combined, these increases in total energy and capacity costs to serve PJM load and maintain resource adequacy will be approximately $90 billion, or roughly 19% of the total projected PJM energy and capacity costs over the 2018 to 2032 period. In addition to these cost impacts, the retirement of nuclear and coal-fired units and replacement with NGCC units over-weights the reliance on fuel-insecure natural gas-fired generation and reduces the diversification of the PJM generation portfolio, thereby decreasing the resilience of the bulk electric system during disruptive events or conditions. Significant costs will be incurred without assuring a resilient grid, as NGCCs are not fuel-secure. As stated in the Chao Affidavit to FirstEnergy's initial Comments, "[i]f a regional generation fleet relies too highly on this kind of just-in-time fuel delivery system, the entire bulk electric system could become vulnerable to the uncertainty and interruption of natural gas supply and delivery."

Overview and Scope of Analysis

10. With the GRPR in place, merchant nuclear and coal-fired generating units will receive sufficient compensation to allow them to continue operating (the "Base Case"). Without the GRPR in place, these units are at risk of prematurely retiring due to insufficient compensation (the "Early Retirement Scenario"). The analysis quantified the change in total cost over a 15-year period from 2018 to 2032 to reliably serve PJM electric demand if the at-risk units retire early and are replaced by natural gas-fired generating units (the "Cost Impact").

11. The analysis calculated the projected 2018 to 2032 Cost Impact by projecting the change in total electric energy cost plus the change in total capacity cost to serve PJM load during this time.

Methodology for Calculating Change in Total Electric Energy Market Cost

12. The change in total electric energy cost in PJM resulting from the Early Retirement Scenario was calculated using Navigant's energy market modeling tools[1] to simulate hourly generating unit dispatch and hourly energy prices at each PJM node for the period 2018 to 2032 in both the Base Case and in the Early Retirement Scenario. Forecasted energy prices ($/MWh) were multiplied by projected load (MWh) at each PJM node for each hour of the analysis period, and then summed across all hours and PJM nodes to calculate the total energy cost to serve PJM load in both the Base Case and the Early Retirement Scenario. Energy cost as defined here includes fuel, variable operations and maintenance ("O&M"), and emissions credits costs, but does not include fixed costs such as capital, financing, and fixed O&M. The total energy cost in the Base Case was subtracted from the total energy cost in the Early Retirement Scenario to calculate the change in total electric energy cost to serve PJM load.

13. Over the 15-year period from 2018 to 2032, the total increase in electric energy cost to serve PJM load in the Early Retirement Scenario is projected to be approximately $42 billion (in 2016 $). The major inputs and assumptions used in conducting the energy market production simulation modeling are listed below.

Generating Unit Retirements and Additions (Base Case)

14. Navigant conducts a comprehensive review of the North American generation fleet on a periodic basis to arrive at assumptions about generating unit retirements and additions that are then incorporated into production cost simulation models for Navigant's semiannual Reference Case updates. These Reference Cases are used as the starting point for a variety of

[1] Navigant's energy market modeling tools include PROMOD commercial software with proprietary Navigant inputs and other proprietary Navigant models for further analysis. While the results presented here pertain to PJM, the entire Eastern Interconnect was modeled to include impacts of imports into and exports out of PJM.

consulting activities that we undertake for our clients. In assembling our Reference Cases, we consider a variety of publicly available sources as well as subscription-based newswire services to help us formulate an informed view on the status of existing, potentially retiring, and forecasted future supply resources across all three interconnects, namely the Eastern Interconnect, Western Electricity Coordinating Council, and the Electric Reliability Council of Texas.

15. Generating unit retirement assumptions for the Base Case are consistent with the generating unit retirement assumptions used in Navigant's Reference Case. Differences between this Base Case and Navigant's current Reference Case include updates for plant retirements and additions that had been announced in the few months since our last Reference Case research was completed. Coal-fired generating unit retirements in PJM in the Base Case include units that have announced specific retirement dates and units that will reach the end of their assumed useful lifetime during the study period, and nuclear plant retirements include units that have announced specific retirement dates or that they will not be seeking license renewal at the expiration of their current license.[2] The Base Case for this analysis does not include any additional assumed generating unit retirements due to prospective economic performance prior to the end of their useful lives. In other words, the Early Retirement Scenario demonstrates the impacts of forecasted early retirement of merchant nuclear and coal-fired generating units assumed to occur if the GRPR is not put into place.

16. Generating unit additions to the Navigant Reference Case are evaluated based on a variety of factors. These factors include:

- Evidence that units are under construction or reported to be in advanced phases of

[2] In the Base Case, Navigant assumes that unless otherwise announced, nuclear units will seek relicensing and continue operations through at least 2032.

development;

- Progress on securing and receiving air, land use, and zoning permits;
- Regulatory approvals (e.g., Certificate of Public Convenience and Necessity);
- Whether the developers/owners have secured long-term power purchase agreements, operations & maintenance contracts, or fuel contracts, and procured turbines and other major heavy equipment;
- Whether the project has secured financing, federal, and local tax incentives (e.g., production tax credits);
- Whether the project has cleared in Forward Capacity Auctions or has received Public Service Commission regulatory approval for construction costs to be included in a regulated rate base;
- Whether a project has been designated as a full network resource by the RTO/ISO;
- Review of RTO/ISO and utility long-term planning documents and lists of assumed future additions;
- Progress of the unit at various stages in the Generation Interconnection queue (e.g., feasibility study, system impact study, whether an Interconnection Agreement has been signed or not, etc.);
- Assessment of future of environmental policies, existing infrastructure (e.g., regional gas pipeline infrastructure), and local reliability issues; and
- Assessment of regional politics (e.g., involvement of Governor's office in support of or against the project).

Taking into account all of these factors, Navigant forecasts 31 GW of new generation will come on-line in PJM over the 2018 to 2032 period to replace generation that already has announced retirement or is forecasted to retire in the Base Case. Approximately 50% of this replacement generation capacity in PJM is natural gas-fired (simple cycle or combined cycle combustion turbine), with the remainder being hydroelectric, wind, solar, nuclear uprates, and other renewable generation.

17. In sum, Navigant used the best information available—i.e., the data in its Reference Case for its production cost simulation models—in compiling information on generation retirements and additions for use in the Base Case.

Generating Unit Retirements and Additions (Early Retirement Scenario)

18. For the Early Retirement Scenario, we identified 161 nuclear and coal-fired generators across the Eastern Interconnect that are not primarily dependent on regulated utility rate base recovery (i.e., merchant units) and that have not been formally announced for retirement (based on ISO deactivation requests and formal company announcements). Units that are included in a regulated utility's rate base are not dependent on the market for financial performance and thus are largely insulated from the problems plaguing the energy marketplace. We then assumed that these units would retire over a period from 2018 to 2022 if the GRPR was not put into place. Total retirements across the four Northeast RTOs[3] include 44 GW of coal-fired capacity and 39 GW of nuclear capacity. Of this amount, 37.6 GW of coal-fired capacity and 29 GW of nuclear capacity is in PJM.

19. We then assumed that, in addition to the assumed generating unit additions represented in the Base Case (from Navigant's Reference Case model), additional "generic" natural gas-fired generating units would be added to replace the capacity associated with the

[3] For these purposes, the four Northeast RTOs/ISOs are PJM, ISO New England, New York Independent System Operator ("NYISO"), and MISO.

Early Retirement Scenario. All of the replacement generic units were sited at appropriate powerflow buses that are in substations that we identified as being within ten miles of an existing gas pipeline, whether at a brownfield coal/nuclear site or mapped to a bus currently designated as a load bus. Approximately one half of the new units were suitable for siting at brownfield sites.

Other Inputs and Assumptions Used in Energy Market Modeling

20. In addition to the generating unit retirements and additions, the following major inputs and assumptions were used in Navigant's energy market modeling:

- Fuel Prices – Natural gas prices were based on Navigant's Reference Case GPCM forecast. Coal prices were based on a forecast by Boyd in collaboration with Navigant's Reference Case. Nuclear fuel prices were based on data from ABB Ventyx.
- Transmission Expansion – Transmission expansion for both the Base Case and the Early Retirement Case was assumed to be the same as Navigant's Reference Case. Similar to the research we conduct for generating unit additions to our Reference Case, we conduct research on a variety of factors to determine new transmission addition assumptions. These are largely based on transmission expansion plans developed and made publicly available by the ISOs/RTOs. A conservative view of transmission expansion was used for this analysis.
- Load Forecast – Navigant relies on the publicly reported load forecasts of each ISO/RTO or NERC Reliability Entity, hourly zonal weather-normalized load shapes compiled by ABB Ventyx, and nodal powerflows from FERC Form 715 filings to produce a nodal load forecast across the Eastern Interconnect that is used in our Reference Case. This load forecast was used in both the Base Case and the Early Retirement Scenario in this analysis.

- Emissions Regulation – Navigant does not assume any U.S. federal carbon regulation; the continuation of the Regional Greenhouse Gas Initiative market across its nine member states is the only carbon legislation effective in the U.S. portion of the Eastern Interconnect in Navigant's Reference Case. Navigant also assumes the continuation of the Cross-State Air Pollution Rule regulation of NOx and SO_2 emissions. These emissions regulation assumptions were used in both the Base Case and the Early Retirement Scenario in this analysis.

Methodology for Calculating Change in Total Electric Capacity Cost

21. Change in capacity prices was projected using Navigant's proprietary Capacity Price Forecast model to project capacity prices in the Base Case compared to the projected capacity prices in the Early Retirement Scenario. Navigant's Capacity Price Forecast model estimates clearing prices in the PJM, ISO New England, and New York Independent System Operator capacity markets. It has also been adapted to model clearing prices in the proposed Independent Electricity System Operator (of Ontario) capacity market. The model is tailored to the different market rules in each of these ISOs, including resource eligibility, locational prices, and auction structure. It can be used both to forecast revenue from entering the capacity markets as well as for scenario analysis of uncertainties (both market parameters and regulatory) that may impact the revenue forecasts.

22. The model is fully consistent with the assumptions and outputs of Navigant's energy market modeling tools. The basic structure of the model is to determine the intersection of supply and demand for capacity in each locational subzone of the markets subject to import constraints from other subzones. The model estimates the capacity demand curve in each ISO following the ISO's administrative rules combined with a forecast of net cost of new entry

("CONE")[4] that uses PROMOD output to estimate the energy revenue that new capacity would expect that would offset capacity revenue. The total capacity supply curve is estimated by calculating the "missing money" for each unit in the PROMOD database and setting the unit bid to the amount needed to be made whole. Imports from other regions and energy efficiency/demand response resources are also considered.

23. The base PJM capacity market has already cleared through the 2020/2021 auction. However, if there are any coal or nuclear units that retire before then, the generation owners would have to replace their capacity obligations. This is not modeled here but does have the potential to raise costs.

24. In the Base Case, near-term capacity prices are relatively flat because PJM is long capacity and there is little need for new capacity. In the Early Retirement Scenario, the rapid retirement of nuclear and coal-fired units causes a need for rapid increase in NGCC capacity being built in PJM. The capacity market is the primary mechanism for incentivizing this capacity and new capacity cannot generally be built in PJM if it does not clear in the capacity market at a sufficient price.

25. In the Early Retirement Scenario forecast, it is assumed that new NGCC generating capacity must execute anchor shipper agreements for long-term firm transportation for gas supply in order for the necessary pipelines to be constructed.[5] Thus, the capital cost of expansion of gas pipeline infrastructure needed in PJM to meet this gas demand is included as a bid adder in the Capacity Price Forecast model. Incremental pipeline investment is estimated to

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[4] Net CONE is defined as the net revenue that a new generating resource would require from the capacity market in order to be built. It is estimated as the capital and fixed costs of the new resource less the expected profit from the energy market.

[5] Notably, execution of a "firm" transportation contract does not assure firm supply as the pipeline can still implement curtailments.

be $25 billion over the period 2019 to 2031. Navigant estimates the additional pipeline capacity to be approximately 11 bcfd across 33 pipeline segments covering approximately 6,278 pipeline miles over this time period. The bid adder for new PJM combined cycle plants is estimated by levelizing these costs and allocating them to each combined cycle plant in each forecasted year of the capacity market.

26. Market-clearing capacity prices from the model for each year were multiplied by the total amount of capacity cleared in each year to calculate the total electric capacity cost to maintain resource adequacy to serve PJM demand in each year in both the Base Case and the Early Retirement Scenario. The change in total electric capacity cost due to the early retirements caused if the GRPR is not in place was calculated as the difference between the total electric capacity cost in the Early Retirement Scenario and the Base Case.

27. Over the 15-year period from 2018 to 2032, the total increase in electric capacity cost to maintain resource adequacy in PJM is projected to be approximately $48 billion (in 2016 $). In the period before 2027, capacity prices rapidly reach net CONE in the Early Retirement Scenario, including the adder for new gas pipeline capacity. Some of the increase in capacity cost is offset because of higher energy prices as the additional energy revenue for the new combined cycles offsets the required capacity revenue. After 2027, the increase in prices in the Early Retirement Scenario relative to the base case declines as base case capacity prices also approach net CONE, and the difference in capacity market prices also declines.

28. In summary, if the GRPR is not put into place and rapid retirement of merchant nuclear and coal units occurs, the total increase in energy and capacity costs to serve PJM customer load and maintain resource adequacy is forecast at approximately $90 billion (in 2016 $) over the 2018 to 2032 period. In addition to this cost impact, the re-distribution of the PJM

generation portfolio with an over-weighting of fuel-insecure natural gas-fired generation reduces the diversity and resilience of the bulk electric system, and increases the risks from disruptive events or conditions, the costs of which have not been quantified as part of the Early Retirement Scenario.

29. This concludes my affidavit.

VERIFICATION OF MICHAEL RUTKOWSKI

I, Michael Rutkowski, being duly sworn, affirm that the foregoing Affidavit of Michael Rutkowski has been prepared by me and/or subject to my direct supervision, and is true and correct to the best of my knowledge, information, and belief.

Michael Rutkowski

Michael Rutkowski

Subscribed and sworn before me this 6th day of November, 2017.

Mary E C

Notary Public

OFFICIAL SEAL
MARY E CONDON
NOTARY PUBLIC - STATE OF ILLINOIS
MY COMMISSION EXPIRES:08/27/18

NAVIGANT

Michael Rutkowski

Managing Director

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Direct: 312.583.6880
Cell: 708.204.0001

Professional Summary

Michael Rutkowski is a Managing Director in the Energy Practice in Navigant's Chicago, Illinois office. Mr. Rutkowski has over 28 years of experience in the energy industry, with significant expertise in the areas of strategy development, energy market modeling business planning, asset management, and operational performance improvement for the power generation and electric/gas utility sectors.

He has led over 30 consulting engagements with energy and utility companies, power producers, natural gas pipelines, equipment manufacturers, and energy services companies (ESCOs). Also a registered Professional Engineer, Mike has a unique ability to bridge corporate and business unit strategy with energy market and operational considerations to provide sound operational improvement and investment decision-making support to his clients.

Professional Experience

Power Generation

» Conducted forward-looking profitability analysis for company's fleet of PJM coal and nuclear generation units through energy market modeling of each unit's dispatch under several scenarios, including varying natural gas and coal prices, increased unit retirements, alternative bid strategies of all PJM units, seasonal shutdown strategies, and different capacity market auction results. Conducted PROMOD market simulation for each case, and modeled return-on-equity (ROE) for each PJM generating unit to show the relative profitability of each unit in each scenario. Presented results to company senior management and facilitated discussion on future generation investment, operations, and retirement decisions.

NAVIGANT

Michael Rutkowski

Managing Director

» Prepared and submitted expert testimony on behalf of PJM Utilities Coalition (FirstEnergy, AEP, DP&L, Buckeye Power, East Kentucky Power Cooperative) in FERC Case EL15-29-00 on PJM Capacity Performance market design. Analysis included production simulation modeling and PJM supply stack analysis to estimate future profitability (as measured by Return on Equity) of merchant coal and nuclear generating units in PJM under multiple capacity market scenarios.

» Led the benchmarking assessment for a fleet of coal generating units transitioning from a traditionally regulated to a merchant business model as a result of state restructuring. Conducted cost, operational performance, and staffing benchmarking and on-site plant reviews to understand current state and opportunities for improvement. Developed future scenarios for merchant business outlook and gross margin implications on the plants. Conducted forward-looking profitability analysis, considering gross margin projections, capital requirements for new environmental controls, administrative & general (A&G) costs, and improved plant O&M costs. Project enabled senior management to make well-informed decisions regarding future viability of continuing plant operations.

» Led the analysis of projected profitability and reliability of merchant coal and nuclear generating units in the PJM wholesale electricity market to support capacity market reform advocacy efforts of a large merchant generation owner in PJM. Generating unit reliability and maintenance spending trends were analyzed to assess the probability of reliability degradation among PJM coal generating units (and potential for system reliability issues) in the next five years. Unit-level profitability for the next three years was modeled to identify coal and nuclear units at risk for retirement and to assess the system-wide reliability and economic impact of potential unit retirements.

» Developed generation "Playbook" of strategies for North American power generation unit of a major global energy company. Facilitated a team of senior executives to confirm long-term goals and aspirations; Conducted market analysis to characterize markets for Combined Heat & Power (CHP), Large-Scale Renewables, Central Thermal Generation, and Grid Services; Facilitated brainstorming sessions to analyze company strengths/weaknesses/opportunities/threats (SWOT); Prioritized opportunities based on market attractiveness and strategic fit; Defined implementation plan including market entry approach, resource requirements, and schedule. Project enabled client to re-focus generation business to meet corporate growth goals.

» Led analysis to support negotiations for a major industrial electricity customer during the potential merger of its electric utility. Client's potential electricity rates were analyzed under a number of scenarios for the merging utility's future structure, which included possible divestiture or closure of a generation plant serving the industrial customer. Electric supply alternatives of on-site combined heat and power (CHP) development and purchasing from retail energy marketer were also evaluated. Recommended the least cost/lowest risk alternative for client to pursue, and supported negotiations with outside parties involved in that alternative. Project resulted in client's ability to secure long-term electric supply in a manner consistent with its overall business strategy.

Michael Rutkowski
Managing Director

- Conducted market analysis of solar photovoltaic (PV) commercial/industrial and residential offerings to assist investor-owned utility in development of community solar offering. Researched community solar efforts of other utilities in terms of regulatory treatment, scale, market approach, and level/pace of uptake. Assessed likely solar PV offering structures and pricing ranges in client's home state to provide input to structure and pricing of client's community solar offering. Project enabled client to secure senior management and state regulatory approval to move forward with large-scale community solar project.

- Led the assessment of power generation and gas pipeline development opportunities in the Midwest U.S. for a major energy company. Identified state, regional, and national drivers for generation investments, including policy, commodity price outlook, and expected plant retirements and new additions. Project included development of a predictive economic model for projecting coal generation plant retirements, as well as a complete electric production simulation modeling effort to determine new gas-fired generation capacity needed to meet reserve margin requirements. Project resulted in recommendations for new investment in natural gas pipelines and power generation assets needed to address the impact of coal plant retirements in the coming years.

- Led the decision analysis for a coal generation plant owner faced with numerous upcoming EPA air emission and water regulations. Identified possible future scenarios of regulations and energy commodity market prices, developed alternative compliance plans consisting of environmental control investments and allowance purchasing strategies, and conducted financial analysis of each scenario/compliance plan combination under a range of sensitivities. Addressed risk through a real option analysis of potential paths forward incorporating learning and key decision points. Developed recommendation for investment plan based on optimal combination of cost and risk to the plant owner.

- Oversaw development of a long-term generation portfolio strategy for major investor-owned utility, focused on identifying optimal strategic options and resource plans to meet ongoing and forecasted load, provide the least cost to customers, and meet obligations to shareholders. Assessed client's existing assets and resource plan and determined opportunities and gaps related to renewables, regulation/carbon, and energy efficiency. Defined potential future scenarios (current trends, low growth, high growth, escalating costs, green world/increased regulation, etc.), analyzed impacts on dispatch order, marginal supply choice, and investment strategies, and identified preferred portfolios under each scenario utilizing a detailed supply and demand resource optimization model. Incorporated Monte Carlo simulations to examine each portfolio's response to risk. Recommended a risk adjusted flexible portfolio strategy to client's management team.

- Led project team that developed a life-cycle economic model for a major supplier of next generation nuclear power plants. Evaluated new plant design features and their impact on staffing levels, capital investment, and operations and maintenance (O&M) costs, and determined future estimates for this plant design. Developed financial model, including major drivers of financial performance, financial statements, financial comparison ratios, and numerous sensitivity cases for analysis of future profitability and cash flows associated with next generation plant design. Project resulted in client's ability to quickly analyze financial cases associated with prospective plant developments using their technology.

Michael Rutkowski

Managing Director

- Led a fleet-wide operational performance improvement project for a major independent power producer (IPP) with over 7,000 megawatts (MW) of fossil generation. Benchmarked the cost and operational performance of each generating unit versus comparable peer units, identified improvement potential through in-depth plant assessments versus fossil plant O&M best practices, and facilitated the development of long-term performance goals with plant and corporate management. Identified and managed a program of over 15 performance improvement initiatives to achieve long-term targets. Established Continuous Improvement Infrastructure and Methodology to sustain results and improve performance in the future. Project resulted in identification of over $30 million in annual benefits and a transformational plan to achieve these benefits. Assisted with implementation of these initiatives over a three-year period.

- Evaluated the commercial impacts and societal benefits of a large proposed compressed air energy storage (CAES) electric power plant in the PJM marketplace. Project included evaluation of the unique technical and operational capabilities of the CAES plant, modeling of plant dispatch in the PJM electric market, quantification of potential revenues from energy, capacity, and ancillary services, and analysis of the potential societal benefits of the CAES plant, which included support of wind power development and reduced overall electric system costs.

- Benchmarked the costs and staffing for the Administrative and General functions (i.e., Finance, HR, IT, and Legal) for a major North American IPP, and identified differences among this company and a peer group of utility generation business units and other IPPs. Made recommendations to management to reduce costs and improve service levels of these functions.

- Led the establishment of the annual business planning process for a major IPP with fossil and wind generation assets. Conducted benchmarking, long-term target-setting, and identification of strategic initiatives, and linked these activities to the annual budgeting and capital planning cycle. Project resulted in a standardized, repeatable annual process that will tie together strategic planning, budgeting, and operational performance measurement.

- Developed scope and implementation plan of corporate-wide continuous improvement program, and assisted with program launch activities, for a major global independent power producer with over 40,000 MW of generation. Project included conducting a readiness assessment of business units to understand the applicability of various aspects of continuous improvement, facilitating senior management sessions to gain alignment and consensus on the scope and direction of continuous improvement, developing the business case for the program, evaluating and selecting initial methodologies and tools (e.g., Six Sigma, Lean, and PDCA), and assisting with implementation planning and launch activities, including the internal branding of the program.

- Led the development of operational strategies for the generation business unit of a major investor-owned utility. Worked with the generation senior management team to develop a common understanding of the impact of long-term corporate earnings expectations on the generation business unit, translated these into operational and cost performance targets, and facilitated the development and communication of the major operational strategies to achieve the targets.

NAVIGANT

Michael Rutkowski

Managing Director

- Led an operational and cost benchmarking project for an 8,000-MW fossil generation portfolio of an investor-owned utility. Identified the major drivers of performance for each generating unit based on its operational role and physical limitations, gathered operational and cost information on each unit, and compared each to a peer group of comparable units. Identified the improvement potential of each unit to facilitate the development of fleet-wide performance goals and improvement initiatives.

- Supported a Central Texas based utility in its strategic mission to review power plant equipment reliability performance and practices with the goal to transform into a world-class reliability organization. The client's market was changing to a nodal market, and reliability would have a higher value under the new market conditions. Beyond the new market conditions, the client wanted to gain a better understanding of different world-class reliability best practices to its fleet. A further reason for the project was to determine best practices for managing the client's aging assets and a strategy to manage through the impacts of its changing workforce. Navigant's team performed a thorough reliability improvement analysis with the goal to transform the generation assets towards world class reliability. To achieve this goal, the project team assessed the client's current cost effectiveness by benchmarking unit cost and reliability against comparable peer units. The team calculated the value of reliability improvement using an economic value analysis of historical market data. The team also performed an extensive market research to assess and compare industry best practices against the client's capabilities. The project resulted in a comprehensive list of prioritized reliability improvement opportunities that the client will implement over a multi-year period.

- Led a long-term performance improvement project at a major global power generation company. Project implemented a structure for long-term performance improvement at over 100 generation plants in order to achieve a goal of top decile financial and operating performance. The mission, business objectives, performance indicators, performance targets, and improvement initiatives were developed for each plant, along with the process and supporting tools for off-site and on-site reviews of each facility by a newly established corporate performance group. The project identified fleet-wide improvement initiatives (currently being implemented) based on the consolidated improvement plans from the plants and the results of the corporate performance group reviews. In addition, various Continuous Improvement Programs were evaluated and assessed for applicability to the company's culture, environment, and business goals. Over $180 million in performance improvement initiatives was identified.

- Managed a fleet-wide maintenance and reliability improvement program to reduce non-fuel O&M (NFOM) costs and reduce equivalent forced outage rate (EFOR) at over 100 generation plants in a major global power generation company's portfolio. Project included the development and pilot implementation of a global model for the processes critical to maintenance and reliability, including increasing plant awareness of the value of performance improvements, identification of high-priority areas through reliability-centered maintenance (RCM) and other technical approaches, economic evaluation and prioritization of alternative maintenance strategies and solutions, and execution of improvement initiatives through outage planning, scheduling/work management, effective work practices, and equipment documentation and performance monitoring.

NAVIGANT

Michael Rutkowski

Managing Director

- Led reengineering effort of the power generation business of a major Midwest electric and gas utility. Every aspect of the business was examined, including O&M and procurement work processes, organizational design, information and technology requirements, performance management systems, interfaces with the fuel procurement and power marketing groups, and cultural impacts. Conducted financial analysis to identify over $60 million in cost savings, which will result in a reduction of approximately 20% in the company's busbar generation costs. A detailed implementation plan was developed to guide the company through the implementation effort.

- Developed a standardized process for major outage planning and execution across a fleet of coal generation assets. Developed milestone schedule beginning 24 months prior to outage start date, including major activities associated with scope definition, condition assessment, schedule development, project budget tracking, contracting, outage management, and close-out. Developed standard tracking mechanisms to proactively identify outage planning issues prior to outage start. Documented process and associated toolkit in company-standard Major Outage Planning Manual. Project resulted in reduction in outage extensions and better overall quality of executed outages.

- Led a cross-functional team of fossil plant maintenance managers, planners, schedulers, supervisors, and operations liaisons in the optimization of routine maintenance planning processes following the implementation of a new maintenance management system. Defined processes for work initiation notification, work planning, scheduling, execution, and closeout. Defined responsibilities of Operations, Maintenance planners, schedulers, supervisors, and Procurement. Developed standard company procedure for routine maintenance planning based on the improved processes. Developed process metrics for work order backlog management, work order scheduling, maintenance effectiveness, stores/procurement functions, and work order closeout. Rolled out process to seven generating plants, and monitored process results until it was self-sustainable. Project resulted in lower maintenance costs, less expediting of parts/materials, reduced equipment downtime, and improved reliability.

- Led the market assessment of the coal-fired generation mercury control market for the provider of on-site, small-scale activated carbon production plants. Project included an assessment of the market for activated carbon for mercury control, including the expected penetration rate for this new technology, including interviews and focus groups with coal generation plant owners as potential customers. Project also assessed the costs, financing mechanisms, and potential revenue streams from offering the new plant, identified major risks, and evaluated the financial viability of this new business to meet company financial goals.

- Assisted the U.S. Department of Energy (DOE) loan guarantee program in investment due diligence of a mercury removal technology and manufacturing facility. Reviewed applicant's business plan, market sizing and operating assumptions, and financial model. Assessed company's competitive positioning relative to pricing, quality, and product offering. Quantified the likely impacts of regulatory, market, and operating risks on project's financial projections. Documented key findings, summarized risk assessment, and proposed business plan recommendations in a comprehensive report to the DOE

NAVIGANT

Michael Rutkowski

Managing Director

Energy Trading/Fuels/Wholesale Marketing and Sales

- Led an assessment of the natural gas purchasing and hedging function for a major public power entity with nuclear, hydro, coal, and natural gas generation assets. Project evaluated the impacts of changing and volatile fuel supply needs on gas purchasing and hedging organization, processes, policies, transaction strategies (physical and financial), and the role of natural gas storage and pipeline assets. Project developed a detailed gap analysis between company's current state and industry best practices, and developed detailed recommendations and implementation plan to improve performance.

- Led the development of business unit strategy for coal and gas services organization within the fossil generation business unit of a large public power entity. Planned and conducted two facilitated workshops with 12-15 of the organization's senior executives to develop "Strategy Articulation Map", consisting of Strengths/Weaknesses/Opportunities/Threats, Mission/Vision/Values, Strategic Objectives, Key Performance Indicators, Improvement Initiatives, and Critical Processes. Developed detailed executive presentation for the Chief Operating Officer, and assisted with implementation planning and rollout of the strategy across the entire public power entity.

- Led the development of a fuel purchasing and hedging strategy for a major fossil generator and wholesale energy trader. Developed coal purchasing contract position guidelines and purchasing decision approval authorities, and performance indicators and targets for effective fuel purchasing, and established a process for use of financial instruments in hedging fuel purchases.

- Developed analytical model for identifying the sources of, and quantifying, the value of natural gas storage to the fuel purchasing group of a major power generator with nuclear, hydro, coal, natural gas, and renewable generation. Project quantified the value derived from natural gas storage assets in 1) mitigating risks of generation unit outages within the company's generation fleet, 2) responding to unexpected daily changes in generation unit dispatch as a result of commodity price changes and other market drivers, and 3) as a means to capture market opportunities due to volatility in natural gas market prices. Developed process and supporting tools to measure the benefits of natural gas storage throughout the year.

- Assisted major Northwest power marketer in developing asset strategy to support trading activities. Project included evaluating level and type of generation assets required to meet corporate growth objectives, screening various existing asset opportunities, and developing an asset valuation model based on forward electric and gas forward price curves. Project resulted in client's ability to focus on high-priority asset opportunities aimed at meeting growth goals.

- Managed the development of an "Energy Trading Vision" to assist a major national wholesale energy marketer in its marketing planning activities. Vision involved predicting the state of the industry over the next five years, including growth projections, industry structure, emerging products and services, major players, and keys to success. Initiated successful marketing planning cycle for the client.

Michael Rutkowski

Managing Director

- Managed the development of national wholesale sales plan for a major utility. Identified specific customer targets for wholesale energy commodity and value-added products and services. Generation assets in different regions of the country were analyzed for asset optimization service opportunities as well as a means for sourcing commodity sales. Sales force deployment was then conducted in accordance with the high-priority opportunities, which resulted in the company's ability to focus on the most profitable opportunities.

- Managed the development of a national wholesale marketing plan for a major utility, which included complete segmentation and market size estimation of U.S. market for wholesale electric and gas energy commodity and value-added products and services. Researched purchase decisions of wholesale energy commodity and service buyers, determined the optimal positioning of the company, and identified target segments and product offerings. Project resulted in client's ability to integrate its electric, gas, and value-added products into a single wholesale portfolio.

- Performed business process and supporting systems redesign for the wholesale power marketing organization of a major utility. Baselined energy trading and risk management processes and systems through interviews with client team. Developed a future vision for state-of-the-art processes and systems, and an implementation plan for the client team to reach the future vision. Produced a comprehensive plan for management to implement the initiative within an aggressive time frame.

- Developed marketing plan for wholesale power marketing subsidiary of a major utility, which included defining the organization's vision for the next five years, assessing market trends, opportunities, and threats, and performing market analysis on specific products and market segments. Developed detailed strategies, sales goals, and action steps that will enable the organization to meet its vision. Provided the client with a structured approach in meeting its future growth goals.

- Designed work processes, responsibilities, and performance measures for a trading support group in the wholesale power marketing division of a major utility, which included defining processes and procedures necessary for effective risk management. Developed an implementation plan to initiate operations of the new group within an aggressive time frame. Streamlined traders' administrative processes, which allowed them more time to trade.

Michael Rutkowski

Managing Director

Publications and Presentations

Mr. Rutkowski has frequently appeared as a speaker at industry conferences and seminars, and has authored several articles in energy industry publications including the following.

- EEI Continuous Improvement Working Group, Co-founder and lead facilitator, Inaugural meeting April 6-8, 2016.
- Conference Chair and Panel Moderator, "Coal Plant Retirements", FC Gas Intelligence 2nd Annual Natural Gas Power Generation US 2015 Conference, Philadelphia, May 18-19, 2015.
- EEI Strategic Issues Conference, "Continuous Improvement for Energy & Utility Companies", October 2014.
- Electric Power Conference 2014, "Transforming the Coal Generating Fleet for Competitiveness in Tomorrow's Markets", April 2014.
- Power-Gen 2012, "Mega-Panel Session: Coal Plant Retirements", December 2012
- TransCanada Midwest Shipper Conference, "Electric and Gas Interdependency in the Midwest", August, 2012.
- Texas Public Power Association 2012 Annual Meeting, "Trends and Issues in Advanced Metering System Deployments", July, 2012.
- Energy Bar Association 2012 Annual Meeting Keynote Session, "Generation Sector Prospects and the Implications for Transmission Planning, Development and Rates", April 2012.
- "Optimizing Commercial Availability In Coal Plants," Electric Power Conference May 2011.
- "Natural Gas in a Smart Energy Future" (co-authored with Gas Technology Institute), January 2011.
- "What Happened in Texas – Evaluating smart meters and public backlash," *Public Utilities Fortnightly,* December 2010.
- "Goodbye Safe Haven? Risk avoidance drives utility stock performance," *Public Utilities Fortnightly,* March 2009.
- "Greening of IOU Equities," *Public Utilities Fortnightly,* March 2008.
- "Measuring Financial Availability," Electric Power Conference May 2007.
- "Making a Change," *Power Engineering,* October 2005.
- "Gas.Com Inc? A Smokestack Industry Faces the E-future," *Public Utilities Fortnightly,* April 15, 2000.
- "eBusiness: Where to Begin," *Public Utilities Fortnightly*, Supplement Issue, July 2000.
- "Generating Plant Sales and Acquisitions: Who's Doing What, and Why," Public Utilities Fortnightly, February 15, 1999

NAVIGANT

Michael Rutkowski

Managing Director

Work History

Managing Director, Navigant Consulting (2004-present)

Senior Manager, BearingPoint/Andersen Business Consulting (1999-2004)

Principal, CSC Consulting/Planmetrics (1996-1999)

Senior Engineer, Sargent & Lundy, LLC (1991-1996)

Field Engineer, General Electric (GE) Power Generation (1989-1991)

Certifications, Memberships and Awards

Registered Professional Engineer (PE), Illinois (License # 062.048906)

Lean Sigma Program Qualification, Six Sigma Management Institute

Education

Master of Management, Finance and Strategy	Northwestern University, Kellogg Graduate School of Management
Bachelor of Science, Mechanical Engineering	University of Illinois at Urbana-Champaign

<u>Exhibit 3</u>

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	)))	Docket No. RM18-1-000

AFFIDAVIT OF
DR. HENRY CHAO
ON BEHALF OF
FIRSTENERGY SERVICE COMPANY
IN RESPONSE TO INITIAL COMMENTS

I. INTRODUCTION

Q: Please state your name, occupation, and business address.

A: My name is Henry Chao. My business address is 4020 Westchase Boulevard, Suite 300, Raleigh, NC 27607. I am presently Executive Advisor, Vice President, RTO/ISO Markets of Quanta Technology LLC, a consulting firm that helps the electric power industry by providing independent, objective, and practical solutions to the most complex generation, transmission, and distribution challenges.

Q: Did you previously file an affidavit in this proceeding?

A: Yes. I provided an Affidavit that was submitted by FirstEnergy as part of its initial Comments in this proceeding on October 23, 2017.[1] My education and professional background are described in that affidavit as well as in my *curriculum vitae* that was attached to my Initial Affidavit.

[1] *See* Comments of FirstEnergy Service Company *et al*. in Support of the Grid Reliability and Resilience Pricing Notice of Proposed Rulemaking ("FirstEnergy Comments") Ex. 6 ("Initial Affidavit").

Q: What is the purpose of this Affidavit?

A: The purpose of this Affidavit is to address some of the issues raised by various commenters regarding whether existing reliability standards adequately address and provide for the future resiliency of the bulk power system.

Q: Please summarize your affidavit.

A: In this Affidavit I comment on certain aspects of the comments that address reliability and resiliency issues. For instance, I agree with the North American Electric Reliability Corporation ("NERC") that resilient generation is needed to maintain a resilient and reliable electric grid. However, I disagree with those commenters who suggest that such resiliency can be achieved or maintained under the current construct of the NERC Reliability Standards. In addition, I explain that the Reliability Standards generally, and Reliability Standard TPL-001-4 in particular, are inadequate to address the need for resiliency as I see it. Accordingly, the Commission needs to act now to preserve resiliency through the preservation of fuel-secure, resilient generation resources such as nuclear and coal-fired generation and until such time as suitable and cost-effective replacement technologies for nuclear and coal-fired generation are implemented.

II. NERC COMMENTS

Q: Have you reviewed the NERC Comments?

A: Yes, I have.

Q: Do you agree with them?

A: For the most part, I do. More particularly, I agree fully with NERC's recommendation that "the Commission continue to pursue policy reform that recognizes the secure capacity and essential reliability service attributes currently and historically provided by coal and nuclear generation. . . ."[2] I also agree with NERC's statement, among others, that:

> Reliable and resilient operation of the [Bulk Power System] requires a balanced portfolio of diverse generation resources that provide adequate capacity and essential reliability services to meet consumer needs and support the system. The right combination and amount of resources and transmission together maintain adequacy of the system. The changing resource mix is altering this combination, influencing the operational characteristics of the grid and challenging reliable system planning and operation.[3]

As I discussed in my Initial Affidavit, "nuclear and coal-fired generating units with onsite fuel are resilient, provide much-needed grid services, and supply electricity whenever it is needed."[4] In addition, I explained that "[w]ith . . . reliable, resilient, and diversified resources, the U.S. electric system has been providing electrical services to consumers with efficiency, reliability, and price certainty that has not been easily subject to fuel supply interruptions."[5] I cautioned however that, "[u]ntil such a time equally resilient options [to nuclear and coal-fired generation] are available, retiring such assets presents serious risks to bulk electric system reliability and resiliency."[6]

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[2] NERC Comments at 1-2. I also do not disagree with NERC's recommendation that such policy reforms also "incentivize[] development of such reliability attributes in non-synchronous resources, such as wind and solar facilities, and promote[] fuel assurance for natural gas-fired resources." *Id.* at 2. But the focus of my Initial Affidavit and this one is nuclear and coal-fired generation so I do not discuss further these other NERC recommendations.

[3] *Id.* at 2.

[4] Initial Affidavit at 13.

[5] *Id.* at 8.

[6] *Id.* at 20.

Q: Do you agree with NERC that the market should compensate certain generators for reliability purposes?

A: Yes. NERC states in its Comments: "Recognizing the need for sufficient capacity, the Commission has approved market mechanisms compensating certain generators for reliability purposes."[7] NERC cites in particular the ability of the Midcontinent ISO "to designate coal-fired or other facilities planned for retirement as 'System Support Resources'" and states that "it is appropriate for the Commission to consider the reliability attributes provided by coal and nuclear generation to ensure that the generation resource mix continues evolving in a manner that maintains a reliable and resilient [Bulk Power System]."[8]

However, this mechanism for compensating generators at risk of retirement is not enough to preserve resiliency because it is reactive and for the short-term only in response to a retirement notice. It does not address the resiliency issue preventively and proactively. Nor does this mechanism address the root cause of the retirement and, beyond the short-term, will most likely result in a system that is less resilient with less fuel diversity.

Q: Are there other elements of the NERC Comments on which you would like to comment?

A: Yes. Attached to its Comments is an affidavit of NERC's CEO, Gerry Cauley. In it, he states that:

> With appropriate insight, careful planning, and support, the electricity sector can continue to navigate these changes in a manner that results in enhanced reliability and resilience. Even with all the changes underway, the bulk power system

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[7] NERC Comments at 7.

[8] *Id.*

> (BPS) remains highly reliable and resilient, showing improved reliable performance year over year.[9]

Some may argue that this statement indicates Mr. Cauley believes that without a change or enhancement to the current NERC Reliability Standards, reliability assessment practices, or RTO/ISO market rules, the industry can continue ensuring resiliency and reliability of the grid. As I explained in my Initial Affidavit, without a reliability or resilience standard on fuel assurance, there is a disconnect between the generation needed to support resource adequacy and transmission security standards.[10] Nuclear and coal-fired generation—which provide much needed diversity and resiliency qualities to the electric grid—are closing.[11] The lost resilience qualities cannot be replaced by natural gas-fired, wind, or solar generation as they are not fuel-secure. Rather, I believe that it is necessary to retain nuclear and coal-fired generation while the suitable replacement technologies can be cost - effectively implemented.

Q: You discussed in your Initial Affidavit concerns that the NERC Reliability Standards are too narrow in that they only look at electric system components. Can you please elaborate on that point?

A: Certainly. The Reliability Standards focus on planning and operation of the Bulk Power System ("BPS"). More particularly, the Standards focus on the planning and build out of the BPS to meet certain criteria or goals, but they do not mandate planning or build out requirements for generation or fuel supply certainty for generation. Rather, these are largely driven through market rules within RTOs/ISOs that are still evolving. The Reliability Standards do contain performance requirements for generation to a certain

[9] NERC Comments, Ex. A, Summary.

[10] Initial Affidavit at 6.

[11] *Id*. at 21.

extent; but these standards do not fully encompass the need for fuel security and other essential reliability attributes that are necessary for the reliable and resilient operation of the BPS.

The Reliability Standards were developed and determined sufficient based on the portfolio of generation resources in effect at the time the Standards were developed. While some of the Standards have changed over the years, they have not changed as quickly as the generation portfolio in RTOs/ISOs has changed. And as I explained in my Initial Affidavit, they do not fully capture or address the risk to the BPS of high reliance on natural gas as a fuel source for generation supporting the BPS.[12] The Reliability Standards do, of course, set forth reliability criteria and define design conditions and sensitivities to be considered in planning and operations, but these design conditions and sensitivities fail to encompass events—such as fuel unavailability or major natural gas pipeline disruptions—the likelihood and severe consequences of which we are only beginning to appreciate and understand.

Q: Are there any Reliability Standards in particular that you think get close to addressing your concerns but do not go far enough?

A: Yes. Reliability Standard TPL-001-4 is what I would call the "core" standard governing planning of the Bulk Electric System. Its stated purpose is to "Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System

[12] *Id*.

conditions and following a wide range of probable Contingencies."[13] The Rules within this Standard require Transmission Planners and Planning Coordinators to plan their systems in a manner that ensures load can be supplied without interruption and assuming the possibility of various adverse events (i.e., "Contingencies").

The scope of the planning required by TPL-001-4 is limited however because it only looks at the impact of the loss of a generator or transmission component to the electric grid. As I discuss below, neither TPL-001-4 nor any other Reliability Standard enforces any consideration of the loss of other delivery components.

As I discussed in my Initial Affidavit, "[t]he default assumption [in the TPL-001-4 analysis] that the needed generators are always available no matter what fuel are they burning can lead to an unsecure and unreliable transmission system."[14] In addition, "[a] failure of a natural gas pipeline can result in multiple power plants being unable to produce electricity, which in turn results in the inability of the system to supply the load or to maintain transmission system security. This single common-mode failure can affect more than one transmission control area, causing simultaneous resource shortfalls in multiple regions and curtailing reliability assistances under emergency conditions between the regions."[15]

As a result, the planning reviews required by the Standard do not look out far enough in time to identify issues that might arise from premature, economic retirement of nuclear and

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13 NERC, Reliability Standards for the Bulk Electric Systems of North America, Apr. 1, 2016, TPL-001-4 § A.3 (Purpose).

14 Initial Affidavit at 15.

15 *Id.*

coal-fired generation, nor do the reviews consider events such as pipeline outages that may adversely impact dozens of natural gas-fired generating units.

Thus, I think TPL-001-4, while certainly needed to help ensure reliability, is insufficient to maintain resiliency and reliability in view of the current pace of retirement of nuclear and coal-fired generation. In other words, entities can plan their systems in a manner that fully satisfies TPL-001-4 but still be at a considerable risk of outages (i.e., losses of load) due to the standard being too narrow to address the impact of fuel unavailability.

Q: Do you believe that NERC has done an appropriately comprehensive review of whether the existing BPS is resilient?

A: No. In addition to the inadequate TPL-001-4 related practice, I also discussed in my Initial Affidavit the inadequate practice in the assessment of resource adequacy. I stated: "The default assumption in resource adequacy assessment and capacity market clearing is that the primary fuel source is always available. . . . [F]uel supply interruption is considered as 'outside management control' and explicitly excluded from EFORd data reporting and calculations. The EFORd reporting and calculation method is the industry standard for measuring generator performance. Including interruption of fuel supply in the EFORd calculation would worsen a generator's performance as measured by the EFORd."[16]

I do not see in NERC's Comments any indication that, in reaching its assessment that the BPS is resilient, it has conducted a review of the BPS broader than that required under TPL-001-4 and current resource adequacy assessment practices. That is why I believe the Commission needs to act now to prevent the further closure of fuel-secure generation.

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16 *Id*. at 14.

Until such time as the Commission can properly and comprehensively analyze and determine what level of such generation will be needed in the future to maintain resiliency, we must not lose any more fuel-secure generation.

Q: What do you recommend be done at this time?

A: I strongly recommend that the Commission direct NERC and RTOs/ISOs to correct the deficiencies in the Reliability Standards and market rules discussed in this and my Initial Affidavit, and in the meantime as an interim measure, accept the FirstEnergy proposal to stop the premature retirement of these facilities while the issue can be studied thoroughly. I believe it is imperative to analyze the fuel availability issue and its impact on the assumptions and industry practices before the Commission can reasonably conclude that the current or contemplated RTO/ISO rules or mechanisms or the NERC Reliability Standards are sufficient to address the resiliency requirement. Since it may take a long time for the industry to perform such studies and reach consensus, it is appropriate for the Commission to first act to preserve the resilient units as contemplated in the Proposed Rule. Once fuel-secure, resilient nuclear and coal-fired generation retires, it is gone for good. Until such a time equally resilient options are available, retiring such assets presents serious risks to bulk electric system reliability and resiliency.

Q: Does this conclude your affidavit?

A: Yes, it does.

VERIFICATION OF HENRY CHAO

I, Henry Chao, being duly sworn, affirm that the foregoing Reply Affidavit of Henry Chao has been prepared by me and/or subject to my direct supervision, and is true and correct to the best of my knowledge, information, and belief.

Henry Chao

Subscribed and sworn before me this 7 day of November, 2017.

Notary Public

LISA HECKER
Notary Public, State of New York
Qualified in Schoharie County
Reg. No. 01HE6341522
My Commission Expires 05/09/2020

Exhibit 4

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

State of Reliability 2017

June 2017

RELIABILITY | ACCOUNTABILITY




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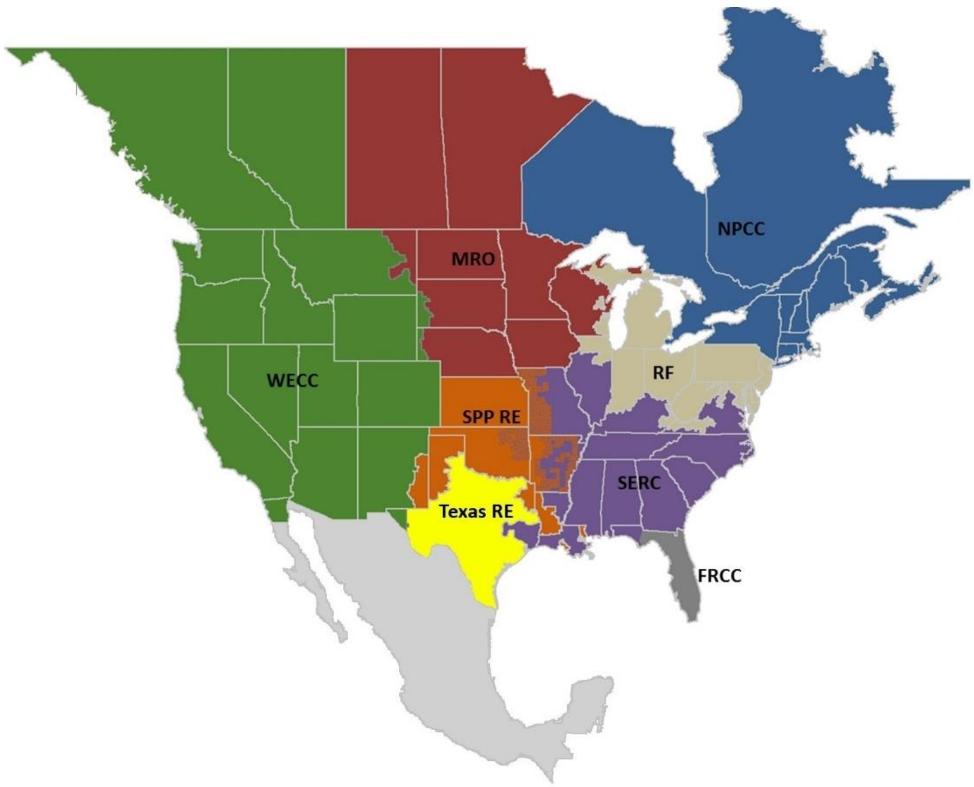
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

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 eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

NERC, as the ERO of North America, is tasked with the mission of assuring the reliability of the North American BPS. This is accomplished in a variety of ways, including through independent assessments of BPS reliability and the documentation of results in a periodic report. The *State of Reliability 2017* focuses on the performance of the BPS during 2016 as measured by an established set of reliability indicators (metrics) for comparison to previous years to identify trends.

Based on this report, the BPS provided an adequate level of reliability (ALR)[1] during 2016. In addition, risks to reliability, key areas for improvement, and highlights of ongoing work by industry to improve system reliability and resiliency were identified. This report summarizes the results from ongoing activities to promote reliability across multiple fronts, including reliability assessments and system performance analyses. Analysis of system performance enables NERC to examine trends and identify potential risks to reliability, establish priorities, and develop effective mitigation strategies to control reliability risks. Analysis of system performance data and trends are translated into the key findings below. The corresponding recommendations in Chapter 1 promote further risk assessment and mitigation efforts and help to focus the work and resources of the ERO and the industry.

2016 Key Findings:

1. No Category 4 or 5 events[2] in 2016
2. Protection system misoperation rate continues to decline, but remains a priority
3. Frequency response shows improvement, but requires continued focus
4. Cyber and physical security risk increases despite no loss of load events
5. Transmission outages caused by human error show a slight increase
6. BPS resiliency to severe weather continues to improve

The *State of Reliability 2017* is an independent report developed by NERC with support from industry. The report builds upon several existing NERC activities and deliverables, including those developed by task forces or working groups under the direction of NERC's Planning, Operating, and Critical Infrastructure Protection Committees. These industry groups support NERC in developing recommendations and mitigation strategies for reliability issues, often prompted by specific findings in this and other NERC reports. Specific BPS incidents in 2016 also served as leading indicators or "faint signals"[3] of reliability risks. For example, the California drought-like conditions contributed to the Blue Cut fire transmission line outages, resulting in the cessation of power injection by inverters for a number of solar facilities. Early and ongoing investigation by the ERO contributed to mitigation efforts. These efforts are further detailed in Chapter 2.

Topics in this report are centered on the ERO's Reliability Risk Priorities[4] that were identified by NERC's Reliability Issues Steering Committee (RISC) and accepted by NERC's Board of Trustees in November 2016. Specifically, Cybersecurity Vulnerabilities and Changing Resource Mix were identified as two high-risk profiles that are evolving and maintaining a high likelihood of impact to the reliability of the BPS with mitigation strategies that are often

[1] Definition of "Adequate Level of Reliability," http://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf

[2] Events on the Bulk Electric System (BES) are categorized sequentially from 1 to 5 with 5 being the highest in severity, as detailed in http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx .

[3] Seeing the Invisible: National Security Intelligence in an Uncertain Age. Thomas Quiggin, World Scientific, 2007

[4] http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

less certain than lower risk profiles. These risks are further explained in Chapter 1: Key Findings, Chapter 2: 2016 Reliability Highlights, and Chapter 7: BES Security Metrics. In addition, Chapter 4: Reliability Indicator Trends presents a list of the original 16 reliability metrics with trending results that show changes to BPS reliability observed in 2016 when compared to previous years. Supporting information for the complete set of metrics is included in Appendix E, while Appendix F explains the relevance of the term "statistically significant," which is used widely throughout this report.

There were no reportable cyber security incidents in 2016 and, therefore, no events that caused loss of load. While this indicates NERC's efforts with industry have been successful in isolating and protecting operational systems from various adversaries, this does not suggest that cyber security risk is low. Recognizing that risk management and determining appropriate and meaningful security metrics is difficult, the NERC Critical Infrastructure Protection Committee (CIPC) and NERC's Electricity Information Sharing and Analysis Center (E-ISAC) have developed a roadmap for future metrics development, including refining the initial set of metrics that are based on operational experience. The roadmap addresses consideration of the challenges associated with collecting security-related data:

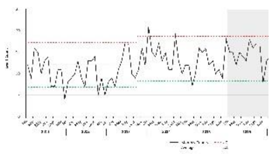
- Historically, NERC and the E-ISAC have limited data related to cyber and physical security incidents as these incidents have been relatively rare and have had little or no impact on BPS reliability.
- The magnitude or number of constantly changing security threats and vulnerabilities is not known with any degree of certainty, particularly as they relate to BPS reliability.
- The number and type of cyber systems and equipment used by the industry is vast, making it difficult to develop metrics that are meaningful to individual entities across the industry.
- Data that details security threats, vulnerabilities, and real incidents is highly sensitive. Handled inappropriately, vulnerabilities could be exposed and new and more sophisticated exploits developed.

The CIPC has researched security metrics developed by leading experts outside the electricity industry and examined more than 150 of these to assess their applicability from a BPS reliability perspective. The CIPC concluded that about 30 of the 150 would be relevant. This assessment underscores the challenges associated with developing relevant and useful security metrics that rely on data willingly and ably provided by individual entities. The NERC E-ISAC and CIPC continue to investigate potential new physical and cyber security metrics.

While the key findings, data, and information in this report are presented independently, they are cross-cutting and demonstrate interdependencies between many of the issues that present unique challenges to the electricity industry. These risks must be strategically monitored and mitigated in order to preserve the reliability of the BPS. NERC's *State of Reliability 2017* report provides a basis for understanding and prioritizing these risks and, more importantly, how these interdependent challenges require ERO-wide coordination to effectively mitigate these risks.

Chapter 1: Key Findings and Recommendations

This chapter presents key findings extracted from the analyses and insights in the body of this report. The key findings and recommendations also include suggestions for additional data collection or analyses for future State of Reliability reports.



Key Finding 1: No Category 4 or 5 Events in 2016

While the number of lower category events did not significantly decline, there were no Category 4 or 5 events and only two Category 3 events for the second consecutive year. Events on the Bulk Electric System (BES) are categorized sequentially from 1 to 5 with 5 being the highest in severity.

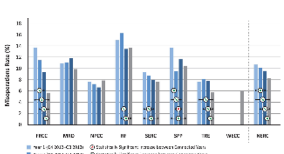
Reviews of these events and those of lower severity resulted in the publishing of 13 lessons learned that shared actionable information with the industry to mitigate risks to BES reliability. For example, the Blue Cut wildfire in California caused transmission faults that cleared as designed, but a number of dispersed solar generation facilities were lost due to erroneous calculations of system frequency. The NERC Event Analysis (EA) Process scans beyond just qualified events to identify and analyze "faint signal" events that are not at mandatory reporting thresholds.

Recommendations

1-1: Emphasize participation in the NERC EA Process:[5] NERC should continue to review events and occurrences to identify reliability risks, measure the success of mitigation efforts, and share valuable lessons learned with the continued support and input from industry.

1-2: Expand lessons learned:[6] Expand the use of outreach beyond published lessons learned and webinars by using interventions, such as multimedia products and better event data analysis sharing. Continue collaborative efforts with the North American Generator and Transmission Forums and others to share reliability information and seek new venues for increased sharing.

1-3: Include vendors and manufacturers in analyses when possible: As the grid continues to rapidly transform, NERC must continue to track and trend occurrences and events to identify, analyze, and provide recommendations for risk mitigation. Augment collaboration with industry thorough the NERC technical committees by including vendors and manufacturers in the technical analysis of equipment performance and specifications.



Key Finding 2: Protection System Misoperation Rate Continues to Decline, but Remains a Priority

The overall NERC misoperation rate is lower in 2016 than last year (8.7 percent, down from 9.5 percent), continuing a four-year trend of declining rates across North America. The three largest causes of misoperations in 2016 remained the same as in 2015: Incorrect Settings/Logic/Design Errors, Relay Failure/Malfunctions, and Communication Failures.

[5] http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

[6] http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx

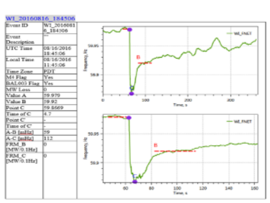
While the misoperation rates for some Regions increased in 2016, the overall NERC 2016 misoperation rate is lower than last year (from 9.5 percent[7] to 8.7 percent), continuing a four-year declining trend across North America. For the first time, the WECC Region's overall operation count was collected, enabling the WECC misoperation rate to be developed for the last two quarters of 2016 (calculated to be 6.0 percent). Using this newly acquired WECC data results in the collective NERC misoperation rate's reduction to 8.3 percent for the measured 2016 year.

Recommendations

2-1: Identify protection system misoperations as a primary focus for industry: Protection system misoperations should remain an area of focus as it continues to be one of the largest contributors to the severity of transmission outages.

2-2: Expand seminars on protection misoperations topic: Continue with and expand upon Regional efforts on education, outreach, and training with industry and stakeholders to reduce protection system misoperations and continue the downward trend.

2-3: Form partnerships to broaden message on misoperations: Continue collaboration with the North American Transmission Forum, vendors, manufacturers, and others to understand, mitigate, and reduce the protection system misoperation rate and impact on the BES. Seek new venues for understanding the challenges associated with the top causes of misoperations and broaden data sharing and information outreach where possible.



Key Finding 3: Frequency Response Shows Improvement, but Requires Continued Focus

Three of the four interconnections showed overall improvement while the Québec Interconnection frequency trend moved from "declining" to "stable." No interconnection experienced frequency response performance below its interconnection frequency response obligation (IFRO).

Frequency response for all four interconnections improved during the 2012–2016 time frame. Adequate frequency response arrests and stabilizes frequency during system disturbances. The addition of a large number of variable energy resources (VERs) onto the BPS has resulted in the need for operational flexibility to accommodate demand while also effectively managing the resource portfolio. This metric should continue to be monitored as the rapidly changing resource mix presents a potential challenge to frequency response,[8] one of the essential reliability services (ERSs). ERSs are comprised of primary frequency response (PFR), voltage support, and ramping capability, all needed for the continued reliable operation of the BPS. As VERs are becoming more significant, NERC is developing sufficiency guidelines in order to establish requisite levels of ERSs, frequency response being most notable in this case.

Additionally, increasing installations of distributed energy resources (DERs) modify how distribution and transmission systems interact with each other. Many system operators currently lack sufficient visibility and operational control of these resources, increasing the risk to BPS reliability. This visibility is a crucial aspect of

[7] The 2016 *State of Reliability* stated the 2015 rate as 9.4 percent. Further analysis resulted in corrections to data which increased the 2015 rate by 0.1 percent, not significantly impacting the conclusions on protection system performance.
[8] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

power system planning, forecasting, and modeling that requires adequate data and information exchanges across the transmission and distribution interface. The most significant growth in DER penetration is occurring in NPCC and WECC. NERC's Distributed Energy Resources Task Force (DERTF) released their initial report in February of 2017.[9]

Recommendations

3-1: Enhance measurement of frequency response and voltage to quantify the effects from the changing resource mix: NERC should continue to measure the effects of the changing resource mix on frequency response and voltage support, including any effects related to DERs. Many system operators currently lack sufficient visibility and operational control of these resources, which is a crucial aspect of power system planning, forecasting, and modeling that requires adequate data and information exchanges across the transmission and distribution interface.

3-2: Continue modifications to generator interconnection agreements: Regulators and markets should continue to support modifications and improvements to generator interconnection agreements to ensure frequency response capabilities for new generation resources.

3-3: Increase awareness of frequency response challenges: Continued collaboration with the North American Generator Forum and others to increase frequency response awareness and capabilities is required. Continued and expanded efforts on education, outreach, and training to improve awareness of the challenges associated with frequency response are needed to inform all levels of both industry and policy makers.

Key Finding 4: Cyber and Physical Security Risk Increases, Despite No Loss-Of-Load Events

In 2016, there were no reported cyber or physical security incidents that resulted in a loss of load. Nonetheless, grid security, particularly cyber security, is an area where past performance does not predict future risk. Threats continue to increase and are becoming more serious.

Responsible entities report cyber security incidents to the E-ISAC as required by the NERC Reliability Standard CIP-008-5 Incident Reporting and Response Planning. The above finding reports the total number of reportable cyber security incidents[10] that occurred in 2016 and identifies how many of these incidents have resulted in a loss of load. While there were no reportable cyber security incidents during 2016 and therefore none that caused a loss of load, this does not necessarily suggest that the risk of a cyber security incident is low. In fact, the number of cyber security vulnerabilities continues to increase as does the number of threat groups.[11] There were a few nonmandatory reports of cyber incidents in 2016, such as phishing and malicious software, found on enterprise (noncontrol) computers. While none of these incidents resulted in load loss, they are a reminder that cyber security risks are ever present.

[9] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

[10] Ref. NERC Glossary of Terms: "A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity."

[11] Security Metric 7, Appendix G

Responsible entities also report physical security events to the Electricity Information Sharing and Analysis Center (E-ISAC) as required by the NERC EOP-004-2 Event Reporting Reliability Standard. The above finding is a result of the total number of physical security reportable events[12] that occur in 2016 and identifies how many of these events have resulted in a loss of load. This finding does not include physical security events that affect equipment at the distribution level (i.e., non-BES equipment). Both mandatory and voluntary reporting indicate that distribution-level events are more frequent than those affecting BES equipment.

The mandatory reporting process does not create an accurate picture of cyber security risk since most of the cyber threats detected by the electricity industry manifest themselves in the enterprise environment (email, websites, smart phone applications, etc.), rather than the control system environment where impacts could cause loss of load and result in a mandatory report. Occasionally, the E-ISAC receives voluntary notifications from entities that malicious code was found on an employee's workstation or that an attack was detected against the entity's public-facing website.

NERC, in collaboration with the Department of Energy and its national laboratories, is exploring ways control system traffic could be directly captured in a passive and nondisruptive manner in addition to the large data sets of information flowing from the corporate or business systems. Once the Cyber Automated Information Sharing System (CAISS)—which is currently a pilot program—becomes more widespread, the system will allow indicators of compromise (IOC) that may be seen on enterprise information technology systems via the Cybersecurity Risk Information Sharing Program (CRISP) to be compared to any potential intrusions or malicious data collected from control systems, further refining risk metrics to grid operations. These initiatives will assist in developing a better picture of the BPS' security state.

Recommendations

NERC and industry should be guided by the following recommendations in maturing existing metrics and developing new metrics to enhance industry's view of evolving security risks.

4-1: Redefine incidents in more granular form: Redefine reportable incidents to be more granular and include zero-consequence incidents that might be precursors to something more serious.

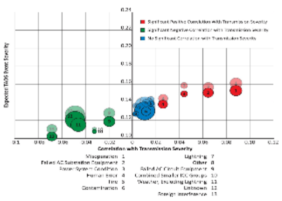
4-2: Run malware signature comparisons to create benchmarks: Use CRISP data to run malware signature comparisons to see how many hits occur on a benchmark set of entities and if any have serious implications for the grid. This metric could be used to provide a percent change from a benchmark year-over-year.

4-3: Characterize type and frequency of cyber threats reported through CAISS data: Use data obtained from CAISS and other similar capabilities to characterize the type and frequency of various cyber threats reported through the year.

4-4: Expand outreach to public and private sector data resources: Include other data sources such as the FBI, SANS Institute, Verizon, etc., as input for understanding the broader security landscape surrounding critical infrastructures.

4-5: Strengthen situational awareness for cyber and physical security: NERC should actively maintain, create, and support collaborative efforts to strengthen situational awareness for cyber and physical security while providing timely and coordinated information to industry. In addition, industry should continue to review its planning and operational practices to mitigate potential vulnerabilities to the BPS.

[12] Reportable events are defined in Reliability Standard EOP-004-2 Event Reporting, Attachment 1.



Key Finding 5: Transmission Outage Rates Caused by Human Error Show a Slight Increase, but no Increase in Outage Severity

The number of automatic (momentary and sustained) transmission outages from Human Error significantly reduced from 2014 to 2015. Year-end 2016 data demonstrates a return to 2014 levels. While no increase in outage severity was discovered, Human Error remains a major contributor to transmission outage severity and will remain an area of focus.

Industry's increased efforts to lower the number of outages defined as "unknown in cause" has resulted in a marked improvement of causal identification, thus less use of the "unknown" descriptor in Transmission Availability Data System (TADS) reporting. It is not clear whether some portion of the increase in Human Error for 2016 may be a result of more deliberate cause coding, thereby reducing outages with an unknown cause, but increasing the rate of outages caused by Human Error. It is important to note that the while the outage rate has increased, the overall correlation with transmission line outage severity has not markedly increased from past years.

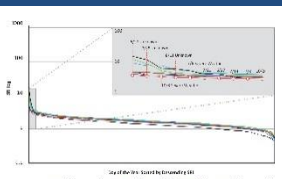
Additionally, outages from Failed Alternating Current Circuit Equipment (insulators, conductors, etc.) have increased from past trends, potentially for the same reason as mentioned previously. Transmission line outages caused by Failed AC Substation Equipment (breakers, transformers, etc.) have remained flat as a trend with neither an increase nor a decrease in the rate of occurrence.

Recommendations

5-1: Increase human performance training and education: NERC should continue to provide focus on human performance training and education through conferences and workshops that increase knowledge and mitigation from possible risk scenarios.

5-2: Increase awareness of human performance issues with industry and policymakers: Explore increased collaboration with the NAGF, NATF, and other groups. Continue to expand efforts on education, outreach, and training to improve awareness of the challenges associated with human performance to inform all levels of both industry and policy makers.

5-3: Initiate focused data collection and assessment: Industry should investigate the possible value of increased granularity of data collection for transmission outages collected in the Transmission Availability Data System caused by Failed AC Circuit Equipment, Failed AC Substation Equipment, and Human Performance.



Key Finding 6: BPS Resiliency to Severe Weather Continues to Improve

In 2016 for the second consecutive year, there were no days that the daily severity risk index (SRI) was part of the top-10 most severe list of days between 2008 and 2015, despite days with extreme weather conditions across North America.

Performance outcomes were determined using the SRI, which is a measure of stress to the BPS in any day resulting from the combination of generation, transmission, and load loss components. In 2016, there were no days that made the daily SRI top-10 most severe list of days between 2008 and 2015; this is despite days with extreme weather conditions across North America. Improvements in the 2016 SRI demonstrate that industry preparedness continues to have a positive influence on BPS resiliency.

Recommendations

6-1: Update the severe weather collaboration process with industry: NERC should continue to expand outreach with industry to improve grid resilience before, during, and after extreme weather events.

6-2: Develop the SRI on interconnection or regional basis: The ERO Enterprise should continue to explore the possibility of developing the SRI on an interconnection or regional basis to provide greater insight into targeted weather mitigation.

6-3: Update the winter weather reliability guideline: In coordination with the NAGF, the NERC Operating Committee (OC) should review and update the Generator Unit Winter Weather Readiness Reliability Guideline[13] to capture lessons learned from previous winters.

[13] http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Generating_Unit_Winter_Weather_Readiness_final.pdf

Chapter 2: 2016 Reliability Highlights

This chapter describes actions taken to mitigate strategic reliability risks and events that occurred to offer further insight into the risks. This insight provided context for the analytical conclusions drawn from the metric data found in Chapter 4 and Appendix E and produced richer conclusions from and key findings for the *State of Reliability 2017* than would have otherwise been possible. In some cases, topics covered in the previous *State of Reliability* reports are re-examined as NERC's understanding has deepened and mitigation efforts have refined. In these cases, some background information will be reintroduced that is accompanied with new insights.

The topics examined in this chapter are closely related to the following high-risk reliability profiles that were identified in the RISC's ERO Reliability Risk Priorities:[14]

- Changing Resource Mix
- Bulk Power System Planning
- Resource Adequacy Performance
- Cyber Security Vulnerabilities

The RISC profile Changing Resource Mix is closely related to BPS Planning and Resource Adequacy Performance. NERC has collaborated with industry to address all three with a focus on ERSs, which are foundational for understanding and mitigating the risks' potential negative impacts on the system. Single points of disruption have also become a greater risk as the resource mix continues to rapidly change. Specifically, increased dependence on natural-gas-fired capacity can lead to greater reliability risks due to the loss of natural gas or other fuel contingencies. Grid security issues and related cyber security vulnerabilities are also examined in this chapter.

Essential Reliability Services

Attention to the changing resource mix in 2016 primarily targeted establishing approaches for measuring ERSs, especially as the penetration of inverter-based generation continues to increase (e.g., solar and wind turbine technologies). NERC's Essential Reliability Services Working Group (ERSWG) is a group of industry subject matter experts that have supported NERC in its effort to inform policy makers on the importance of ERSs.

The ERSWG's support includes the release of multiple deliverables. Among these deliverables are an ERS concept paper,[15] a framework report,[16] and several videos[17] that explain frequency support, ramping, and voltage support. Regulators and industry have since taken additional actions in 2016 to address frequency response and voltage support.

Primary Frequency Response

Increased industry focus on frequency response in recent years (Appendix E: Metric M-4) has paralleled improved system performance. The United States interconnections all demonstrated improved trends 2012–2016 as seen in Table 4.1 and the detailed analysis in Appendix E. Previous frequency response performance in 2012–2015 was inconclusive in the Eastern and Western Interconnections since inconsistent data did not allow for accurate trending. The Québec Interconnection showed similar improvement from declining performance over 2012–2015 to a stable trend 2012–2016.

14 http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

15 http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF Concept Paper.pdf

16 http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

17 https://vimeopro.com/nerclearning/erstf-1

NERC has collaborated with the NAGF to conduct the NAGF Primary Frequency Workshop in 2016, which was attended by NERC, NAGF, and FERC staff in addition to vendors. The NERC Resources Subcommittee (RS) conducted interconnection-level, web-based training sessions on implementation of Reliability Standard BAL-003-1 (R1),[18] and on frequency response and frequency bias setting for industry Balancing Authorities (BAs). The RS also conducted a web-based instruction, Frequency Response Initiative – Generator Event Survey, for Generator Owners (GOs) and Generator Operators (GOPs). Additionally, the RS worked on enhanced frequency response measures as assigned by the ERSWG in its framework report. FERC issued a notice of proposed rulemaking (NOPR) to require new generators connecting to the BES to have the capability to provide frequency response. FERC also modified the *pro forma* Small Generator Interconnection Agreement to require newly interconnecting small generating facilities to ride through abnormal frequency events. These distinct, yet coordinated actions demonstrate a need for these efforts to continue in order to have an effective impact on improvements to interconnection frequency response.

Voltage Support

PAS and System Analysis and Modeling Subcommittee (SAMS) groups, at the direction of NERC's Planning Committee (PC), have worked in 2016 to advance Measure 7–Reactive Capability on the System–from the ERSWG's framework document. PAS completed the related tasks of determining a methodology for data collection to support Measure 7 and used it to solicit a voluntary industry data submission from the identified BAs. PAS submitted the data to the SAMS for further evaluation that is expected in 2017. Similar to its frequency requirement, FERC modified the *pro forma* Small Generator Interconnection Agreement[19] to require newly interconnecting small generating facilities to ride through abnormal voltage events.

Single Point of Disruption

NERC continues to assess the increasing risk of fuel disruption impacts on generator availability from the dependency of electric generation and natural gas infrastructure as a single point of disruption (SPOD). In the past, NERC conducted two special assessments on gas-electric interdependencies; a primer highlighting key considerations in 2011[20] and a detailed framework for incorporating risks into reliability assessments in 2013.[21] As highlighted in previously released NERC *Long-Term Reliability Assessments* (LTRAs), substantial progress has been made in the last five years to improve coordination between natural gas pipelines, gas distribution companies, and electric industries. Even so, there are remaining concerns and opportunities to address on this subject.[22] NERC published its *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*[23] in May 2016. In the document, NERC recommended incorporating fuel availability into national and regional assessments.

Until recently, natural gas interdependency challenges were most experienced during extreme winter conditions and focused almost exclusively on gas delivery through pipelines. However, the recent outage of an operationally-critical natural gas storage facility in Southern California—Aliso Canyon—demonstrates the potential risks to BPS reliability of increased reliance on natural gas without increased coordination between the two industries. In October 2015, a gas leak was detected in a well at Aliso Canyon. The facility is owned by Southern California Gas Company (SoCalGas) and is one of the largest natural gas storage facilities in the United States. It is a critical component of the natural gas system in the Los Angeles Basin, which serves 11 million core natural gas customers and provides gas to 18 power plants with approximately 9,800 MW of capacity in the L.A. basin. Through November and December 2015 as SoCalGas worked to stop the leak, it reduced the amount of working gas stored

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18 BAL-003-1(R1) compliance was effective in December, 2016.

19 https://www.ferc.gov/industries/electric/indus-act/gi/SGIA.pdf

20 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Gas_Electric_Interdependencies_Phase_I.pdf

21 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf

22 http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

23 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf

in Aliso Canyon from 86 Bcf to 15 Bcf. The leak was sealed in February 2016; however, additional injection of gas into the facility was prohibited pending a comprehensive inspection of the 114 storage wells at the facility. The BPS reliability risk of potentially controlled load shedding persisted through the 2016 summer season.

While the situation at Aliso Canyon did not meet the criteria/threshold of an EA Process qualified event, NERC Bulk Power System Awareness (BPSA) began closely monitoring the situation at its onset. NERC BPSA has coordinated with WECC SA to remain informed of the activities surrounding the issue and will continue to collaborate with WECC SA as they determine what, if any, ongoing reliability concerns there may be.

Renewable Penetration and Distributed Energy Resources

California provides a leading indicator of BES performance given the high penetration of renewable and distributed energy resources in the state. It has established a renewables portfolio standard (RPS) of 33 percent by 2020 and 50 percent by 2030. CAISO 2020 (33 percent) studies indicate that, in times of low load and high renewable generation, as much as 60 percent of its energy production would come from renewable generators that displace conventional generation and frequency response capability.[24] Net load is the difference between forecast load and expected production from variable generation resources (renewable generation). The difference is an imbalance between peak demand and renewable generation that strains the grid. Net load is illustrated using what is commonly known as the "duck curve" since the load shape across a day resembles the profile of a duck (see **Figure 2.1**). California's duck curve is already meeting projections for the year 2020. ERO SA and EA have worked to ensure that they are able to detect and mitigate "faint signals" of potential future reliability threats.

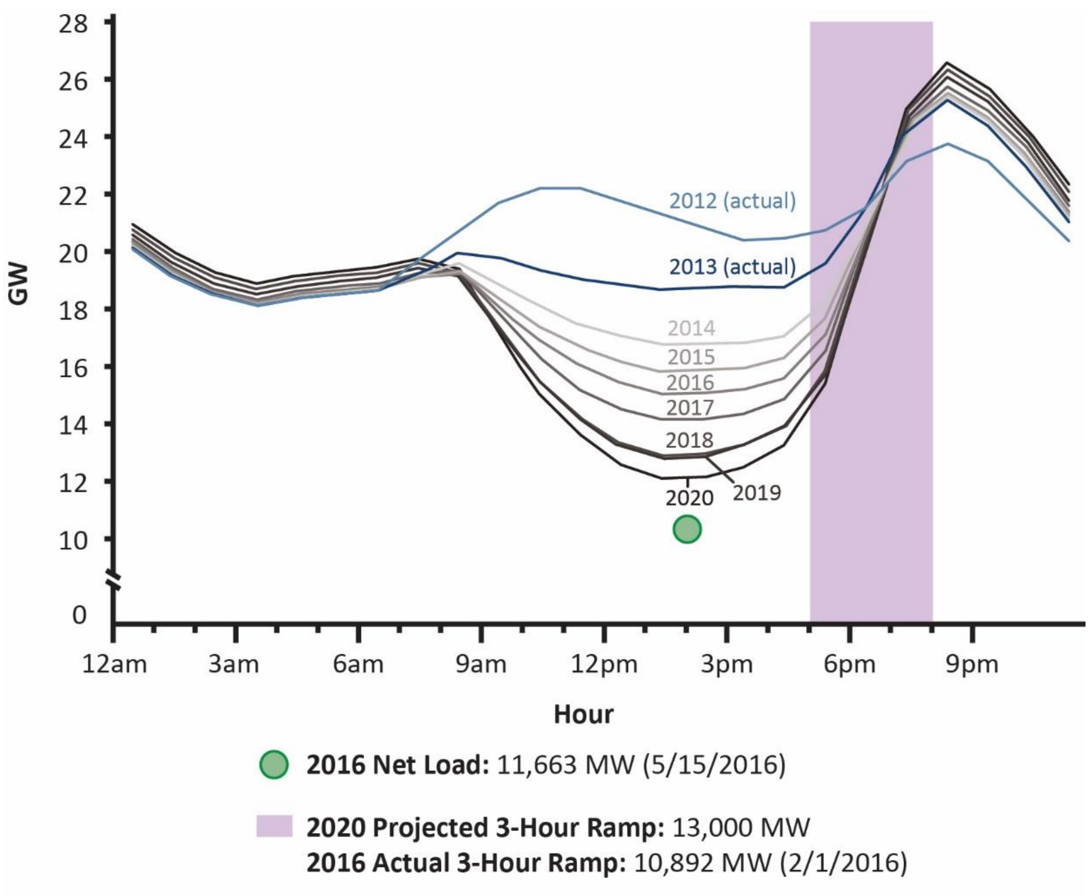


Figure 2.1: CAISO Duck Curve

[24] http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

Unplanned Loss of Renewable Generation

On August 16, 2016, smoke from the Blue Cut wildfire in San Luis Obispo County, CA, resulted in the tripping of two 500 kV lines in the active fire area. There was a noticeable frequency excursion with Peak RC reporting the loss of more than 1,000 MW across multiple renewable resources in the CAISO BA following these line outages. CAISO, SCE, and Peak confirmed that no conventional generators tripped and that all the resources that were lost practically instantaneously were utility-scale renewables, primarily solar.

While not a qualifying event in the ERO EA Process, the occurrence was significant and unusual enough that the ERO requested an event report and worked with the engineers and planners at CAISO and Southern California Edison to better understand this first known major loss of renewable resources due to a transmission system disturbance.

The tripping of the first 500 kV line was due to smoke from the fire creating a fault and the line clearing as designed. The second 500 kV line tripped as a result of a smoke induced fault, again by design, and cleared within three cycles. Before that fault cleared, the transient caused by the fault was experienced at the 26 nearby solar farms (thus the aggregate over 1,000 MWs of generation) and subsequently caused the inverters to quit injecting ac current (within two cycles).

- Many of the inverters stopped outputting power before the fault cleared, indicating that the faulted condition alone created the condition that caused the response as opposed to post-fault system response (transient stability).
- Many inverters calculated frequencies at the inverter terminals which are well outside of the values that would be expected for a normally cleared fault. Many inverters calculated a system frequency in the range of 57 Hz during the fault.
- A thorough analysis of the event and the operating characteristics of the related equipment is underway.

There were also multiple instances of unplanned loss of wind generation observed in 2015–2016 in Electric Reliability Council of Texas (ERCOT), the most severe resulting in the temporary loss of 475 MW. The generation loss events occurred as a result of BES voltage disturbances. These were typically also not qualifying events under the ERO EA Process criteria. Texas RE, in conjunction with ERCOT, gathered information from each event to determine the cause of individual wind turbine loss based on wind turbine type and manufacturer. These analyses were hampered by the lack of high-speed data recording capability that is necessary to determine the magnitude of voltage disturbances at the individual wind plant locations. Preliminary data analytics indicate possible issues with voltage ride-through capability as well as other turbine control system parameters. These events provide insight to challenges discussed in the Essential Reliability Services Task Force Measures Framework Report.[25]

Grid Security

Cyber Security Vulnerabilities remains a high-risk profile relative to BPS reliability. Chapter 7 and Appendix G of this report detail the evolving nature of the risk and progress in the endeavor to measure it. Specifically, the data NERC received in 2016 from OE-417s and EOP-004s show low numbers of cyber penetrations of grid operating systems in North America and few reports of physical intrusions.[26] These low numbers indicate that NERC's efforts with industry have been successful in isolating and protecting operational systems from various adversaries. The numbers are also an indication that the electricity industry's record of breaches is much lower than many other sectors and government agencies that have been victims of numerous data breaches.[27]

[25] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

[26] See Appendix G for the BESSMWG metrics.

[27] http://www.nydailynews.com/news/national/hacker-dumps-info-thousands-homeland-security-workers-article-1.2524440; https://www.scmagazine.com/anonsec-claims-credit-for-nasa-drone-hack/article/528448/; http://www.cbsnews.com/news/irs-identity-theft-online-hackers-social-security-number-get-transcript/.

Electricity Information Sharing and Analysis Center

The E-ISAC's mission is to be a leading, trusted source that analyzes and shares electricity industry security information. The E-ISAC gathers security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity industry across interdependent sectors and with government partners.

Most of the E-ISAC's communications with electricity industry members are via a secure internet portal that was significantly upgraded at the end of 2015. In 2016, the E-ISAC added 1,512 new users to the portal, a growth of 19.5 percent over 2015. As the E-ISAC continues to collect portal activity data, the information will assist the E-ISAC in recruiting new members to the portal and determining how the E-ISAC can best serve members' interests and needs.

Increased physical security and cyber security information sharing will enable the E-ISAC to conduct more complete analysis. Robust data collection over time helps identify important trends and patterns. By providing unique insight and analysis on physical and cyber security risks, the E-ISAC's aim is to add value for its members and assist with overall risk reduction across the ERO Enterprise.

NERC and the electricity industry have taken actions to address cyber and physical security risks to the reliable operation of the BPS as a result of potential and real threats, vulnerabilities, and events. The E-ISAC has started hosting unclassified threat workshops biannually. These threat workshops bring together security experts from government and industry to discuss threats facing the electricity industry. The discussions include a focus on past threats, incidents and lessons learned, current threats that may impact industry, or views on emerging threats. The E-ISAC held its first threat workshop on December 6, 2016, in Washington, D.C. and has future workshops planned.

CRISP

CRISP is a public-private partnership cofounded by the Department of Energy (DOE) and NERC and managed by the E-ISAC that facilitates the exchange of detailed cyber security information among industry, the E-ISAC, DOE, and Pacific Northwest National Laboratory. The program facilitates information sharing and enables owners and operators to better protect their networks from sophisticated cyber threats.

Participation in the program is voluntary and enables owners and operators to better protect their networks from sophisticated cyber threats. The purpose of CRISP is to collaborate with industry partners to facilitate the timely bidirectional sharing of unclassified and classified threat information. CRISP information helps support development of situational awareness tools to enhance the industry's ability to identify, prioritize, and coordinate the protection of its critical infrastructure and key resources.

Chapter 3: Severity Risk Assessment and Availability Data Systems

The severity risk index (SRI) metric quantifies the performance of the BPS on a daily basis. It was designed to provide comparative context for evaluating current and historical performance of the system. Interchangeable use of terms, such as high-risk, high-stress, and high-impact for BPS days, is allowed since the terms are only descriptive of measured SRI within this context. This chapter gives an overview of the metric, its calculation, and the BPS performance in 2016 relative to previous years. It further details the role of the metric's component parts in the determination of the 2016 performance. The three component parts are daily generation loss, transmission element loss, and load loss.

Overview of Severity Risk Analysis

Observations

The 2016 daily SRI has shown solid performance from prior years as expressed by the mean and standard deviation detailed in Appendix A. For each component of the SRI, the following observations can be made:

- **Generation Component:** The generation loss component of the SRI indicates 2011 was the benchmark year for the generation fleet; however, this time period predates the mandatory generation reporting requirements, so it is inconclusive whether that year should be the measure against which subsequent years should be compared.
- **Transmission Component:** With regard to the transmission component of the SRI, 2016 compared to 2015[28] had a higher median and maximum transmission day, but overall less volatility as measured by a lower standard deviation.
- **Load Loss Component:** The load loss component of the SRI in 2016 exhibits the best year of performance demonstrated by smaller values of the descriptive statistics such as mean, maximum, standard deviation, etc. (outlined in Appendix A Table A.5) when compared to prior years.

Calculation for the SRI Metric

Since the inception of the *State of Reliability Report*, the industry has developed the SRI metric, which serves to daily measure the effect of BPS performance. The metric is made of the following weighted components:

- Transmission system automatic outages for voltages 200 kV+
- Generation system unplanned outages
- Distribution load lost as a result of events upstream of the distribution system

Each of the components of the calculation for the SRI metric are weighted at a level recommended by the OC and Planning Committee (PC) as follows:[29]

- Generation capacity lost is divided by the total generation fleet for the year being evaluated and factored at 10 percent of the SRI score.
- Transmission line outages are weighted with an assumed average capacity based upon their voltage level and the daily outages divided by the total inventory's average capacity and factored at 30 percent of the SRI score.

[28] The scope of TADS data collection prior to 2015 applied to momentary and sustained outages of BES elements rated 200kV+. In 2015 it expanded to include sustained outages for elements below 200 kV. This change significantly affected the SRI transmission component. Therefore, comparisons of SRI transmission components are limited to years 2010–2014 for the former collection scope and years 2015-present for the current collection scope.

[29] http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf

- Load lost due to performance upstream of the distribution system is calculated based upon outage frequency for the day, which is divided by system peak loading and is factored at 60 percent of the SRI score.

With these weighted components, the SRI becomes an indicator of the stress on the BPS from capacity loss, transmission outages, and load loss. This daily data is then presented in several different ways to demonstrate performance throughout the year, performance of the best and poorest days within the year, and the contributions of each of the components of the SRI throughout the year.

Interpreting the Yearly Descending SRI Curve

The SRI descending curve shown in **Figure 3.1** demonstrates several components that are valuable for analysis:

- First, the left side of the graph, where the system has been substantially stressed, should be compared to the high-stress days of prior years. This section of the graph is highlighted in a call out box in **Figure 3.1**.
- Second, the slope of the central part of the graph reveals year-to-year changes in fundamental resilience of the system to routine operating conditions.
- Finally, the right section of the curve provides information about how many days with lower SRI scores occurred during any year compared to other years.

2016 Year in Review

The chart shown in **Figure 3.1** outlines that the year's highest impacting days did not significantly stress the BPS as would have been expected. The thumbnail inset further illustrates that the moderate impacts measured during 2016's highest SRI days represented less stress to the BPS than were caused by the highest SRI days in any prior year on record. For example, the maximum SRI value for 2016 was 3.6; the next lowest maximum value of 4.06 occurred in 2013. Additional information on the descriptive statistics (mean, standard deviation, minimum, maximum, and median) of the daily SRI can be found in Appendix A. Based on prior years' analyses of the SRI, a high-stress day[30] has been determined to be a day where the day's SRI score exceeded 5.0. During 2016, no days exceeded this benchmark value; thus, even the more challenging days in the year demonstrated better resilience than in prior years.

[30] High-stress days are days during which BPS performance has experienced noteworthy impacts to any or all of its generation, transmission, or load SRI components. Based on past analyses, days that exceed an SRI rating of 5.0 (on a scale of 0 to 1000) are often memorable and may provide lessons learned opportunities. If no days exceed five, the highest 10 days for the year are generally reviewed for their initiating causes.

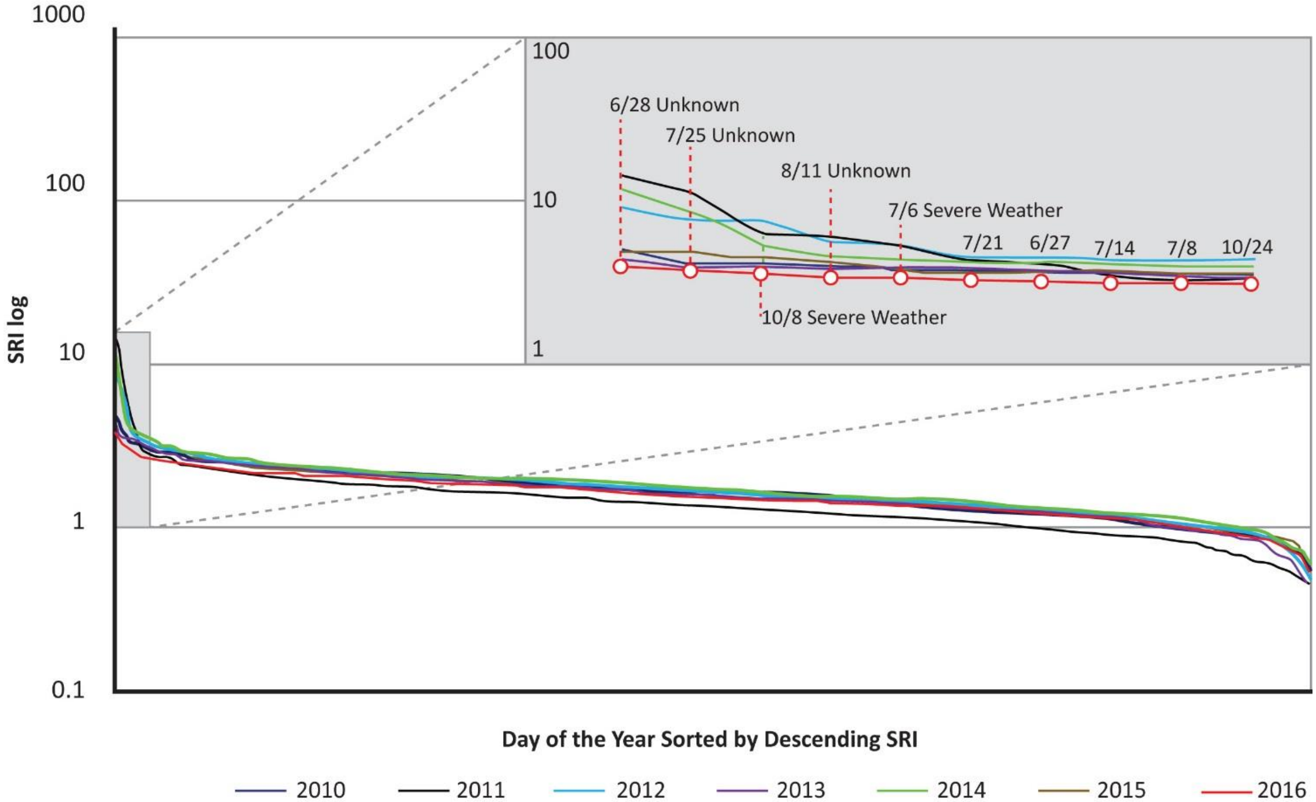


Figure 3.1: NERC Annual Daily Severity Risk Index Sorted Descending

Table 3.1 identifies the top 10 SRI days during 2016 and denotes the weighted generation, transmission, and load loss components for each of these days. It further identifies the significance of each component's contribution to the total SRI calculation, the type of event that occurred, and its general location. General observations include that many of the days were dominated by generation loss and were minimally driven by cold weather with more than half of the days occurring in June, July, and August. PAS separately reviewed DOE OE-417[31] reports to determine any reported event correlations to weather influenced events. In past years, most top SRI days had an associated report indicating that the performance was influenced by weather; however, analysis suggests that the top SRI days are not driven by large reaching weather events in 2016. Instead, the 2016 top SRI days were a combination of many smaller local events, indicating that BPS resilience to the events during the year was high.

[31] https://www.oe.netl.doe.gov/oe417.aspx

Table 3.1: 2016 Top 10 SRI Days									
Date	NERC SRI and Weighted Components 2016				G/T/L	Weather Influenced (Verified by OE-417)?	Rank	Event Type	Region
	SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss					
6/28/2016	3.57	2.64	0.88	0.09			1		
7/25/2016	3.38	2.61	0.64	0.07			2		
10/8/2016	3.14	0.77	2.33	0.13		√	3	Severe Weather	SERC
8/11/2016	3.06	2.39	0.53	0.08		√	4	Severe Weather	RFC
7/6/2016	2.99	2.33	0.59	0.01			5		
7/21/2016	2.90	1.92	0.89	0.29			6		
6/27/2016	2.82	1.84	0.82	0.08			7		
7/14/2016	2.79	1.49	0.83	0.06		√	8	Severe Weather	SERC
7/08/2016	2.73	1.64	0.89	0.14			9		
10/24/2016	2.71	2.18	0.37	0.23			10		

Figure 3.2 reflects a new way of providing insight into the SRI and its evaluation of the BPS performance. It is a daily plot of the SRI score for 2016 (shown in blue) against control limits that were calculated using 2010–2016 seasonal daily performance. On a daily basis, a general normal range of performance exists. This is visible in the gray colored band or within the daily seasonal 90 percent control limits. Days of stress rise above the seasonal daily control limits. **Figure 3.2** indicates that the BPS performance in 2016, as measured by the SRI, was stable with only five days having an SRI value above the seasonal control limits.

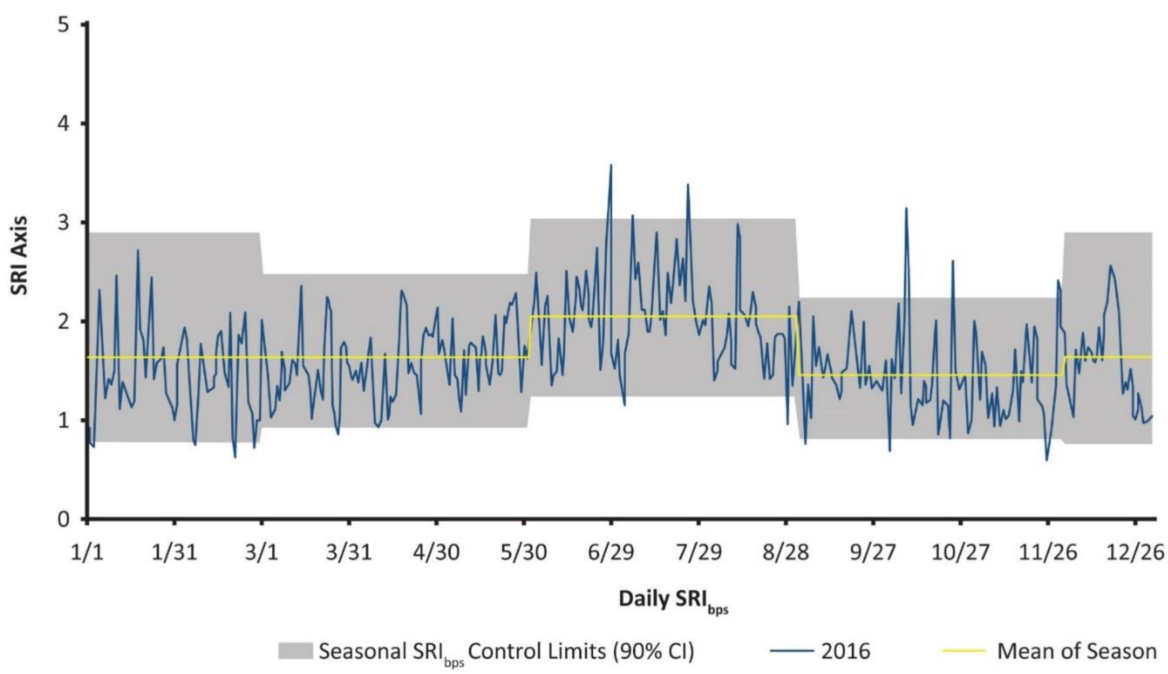


Figure 3.2: NERC 2016 Daily SRI with Top 10 Days Labeled

Table 3.2 identifies the top 10 SRI days for years 2008–2016. These are distinctly different than the 2016 days in **Table 3.1**, in that they are dominated by extreme weather events, and the weighted load loss contributes significantly to the SRI for most of the days.

Table 3.2: Top 10 SRI Days (2008–2016)

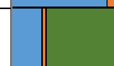
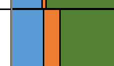
Date	NERC SRI and Weighted Components				G/T/L	Weather Influenced (Verified by OE-417)?	Rank	Event Type	Region
	SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss					
9/8/2011	14.0	1.2	0.8	12.0		**No**	1	Southwest Blackout	WECC
1/7/2014	11.1	9.8	0.9	0.4		Yes	2	Polar Vortex	RF, Texas RE, SERC
2/2/2011	10.8	3.0	0.5	7.3		Yes	3	Cold Weather Event	Texas RE
6/29/2012	8.9	2.6	1.4	4.9		Yes	4	Thunderstorm Derecho	RF, NPCC, MRO
1/6/2014	8.0	6.7	1.2	0.2		Yes	5	Polar Vortex	RF, Texas RE,SERC
10/30/2012	7.2	2.9	3.4	0.9		Yes	6	Hurricane Sandy	NPCC, SERC
10/29/2012	7.0	2.0	1.8	3.2		Yes	7	Hurricane Sandy	NPCC, SERC
4/27/2011	5.8	1.9	3.5	0.4		Yes	8	Tornadoes Severe Storm	SERC
8/28/2011	5.6	0.8	1.6	3.2		Yes	9	Hurricane Irene	NPCC, RF
1/4/2008	5.3	1.2	0.8	3.2		Yes	10	Pacific Coast Storm	WECC

Figure 3.3 shows the annual cumulative performance of the BPS. If a step change or inflection point occurs on the graph, it represents where a higher stress day (as measured by the SRI) occurred. The smoother the slope of the cumulative curve, the less volatile the day-to-day performance of the system through the evaluation period. The year 2016 began with relatively low SRI days and continued this best performance through June. After June, slight escalation occurred, and this moved the cumulative SRI to just slightly poorer than 2011, which stands as the best year on record when comparing annual cumulative SRI_{bps}. There were a few step changes on the curve for the remainder of the year, but a slight increase in the slope occurs at year-end reflecting the minor impact of the beginning of winter weather.

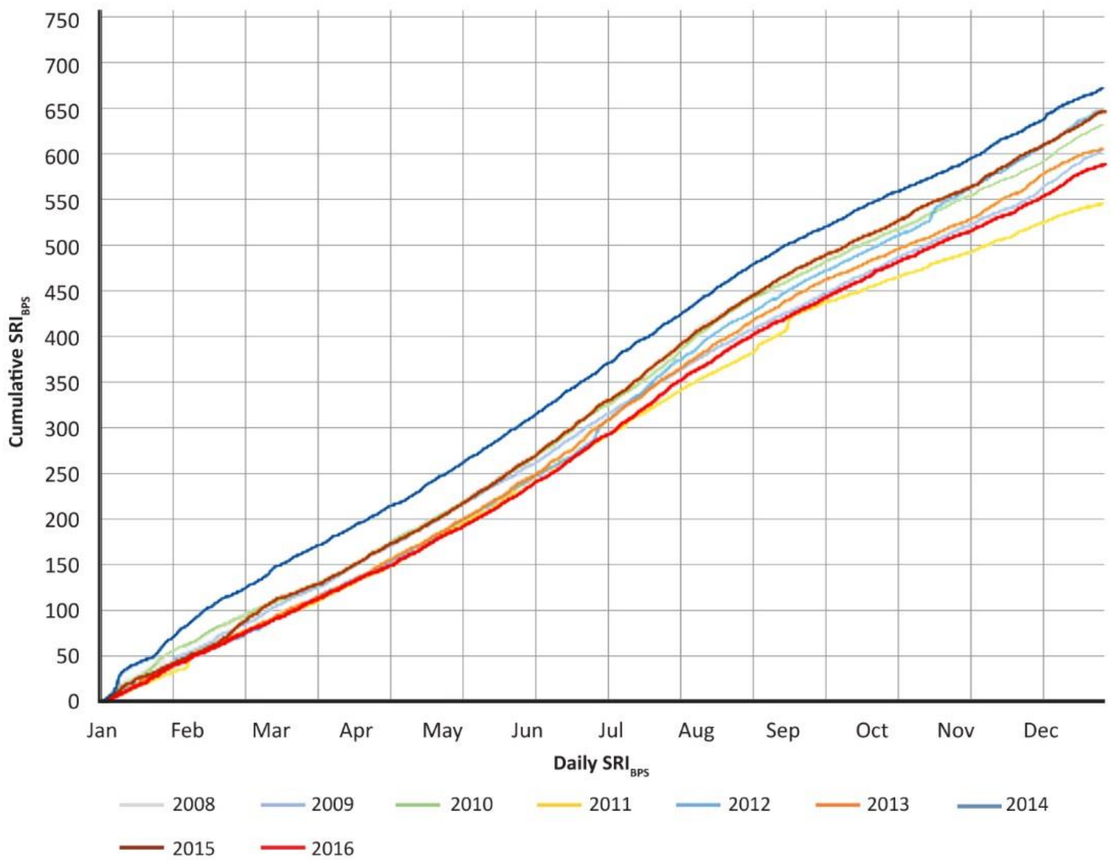


Figure 3.3: BPS Cumulative SRI (2008–2016)

Figure 3.4 breaks down the 2015 cumulative performance by BPS segment. The components are generation, transmission, and load loss in that order. During the year, no single component shows a significant step change for any given day, rather the performance within each segment proves to be very stable. Through the winter and spring, the slopes of each segment are fairly constant, and the generation component does not appear to have any visible deviation to the slope. In the transmission segment, it appears that a slight elevation in its contribution occurs through the summer. The load loss component also reflects a slight increase through the summer season, but also reflects no unusual increase from an individual day. The unplanned generation unavailability component is typically the largest contributor to cumulative SRI.

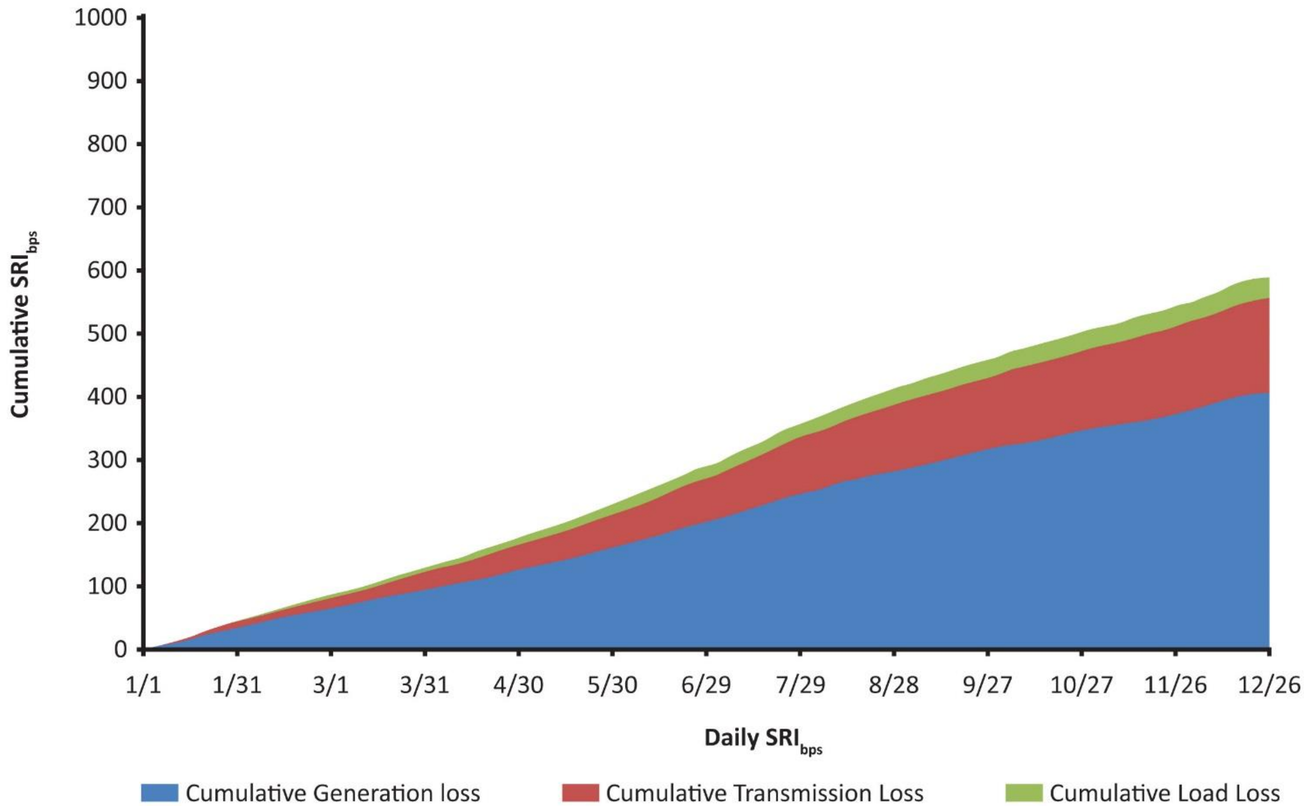


Figure 3.4: NERC Cumulative SRI by Component for 2016

Figure 3.5 provides the history of 365-days of rolling SRI accumulated performance such that each data point represents the value compared to a single year's BPS performance. For example, the point at 12/31/2008 represents the accumulated SRI values of 1/1/2008 through 12/31/2008. The next point on the graph 1/1/2009 would shift the values forward such that it would represent the accumulated SRI values of 1/2/2008 through 1/1/2009.

The trend for performance demonstrates that the best performance has occurred toward the end of 2011 and the beginning of 2012. Since then, SRI performance elevated slightly and generally stayed at that level until the end of 2014, followed by the SRI falling to a fairly stable level in 2015 with improvements reflected through 2016.

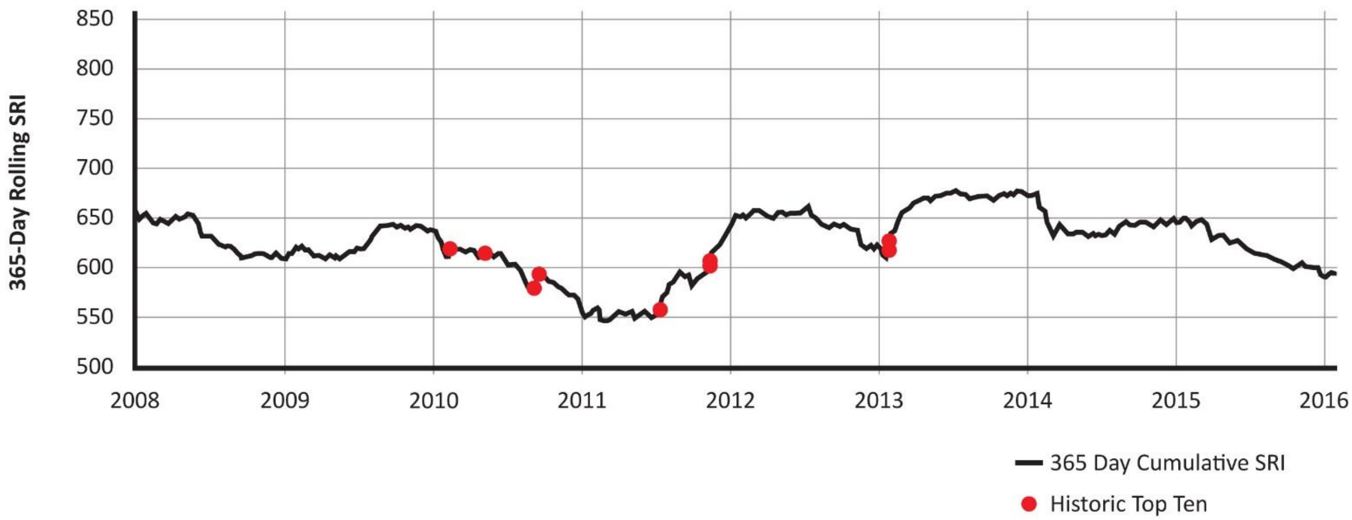


Figure 3.5: 365-day Cumulative SRI 2009-2016

Figure 3.6 further demonstrates the 365-day rolling history that segments the performance by each component. The top chart, in **Figure 3.6**, shows generation loss, which elevated after 2011 and topped out during late 2014. Some improvement occurred during 2015 and appeared to persist through 2016, and this carried through into the composite performance shown in **Figure 3.5**. The transmission component indicates consistent performance through 2009, elevated SRI through 2010, and slight deterioration through 2015 with subsequent slight improvements in the latter half of 2106. The load loss component indicates improvement through 2009 with 2011 and 2012 having several individual step-change days (large load loss events) followed by gradual but continual improvement.

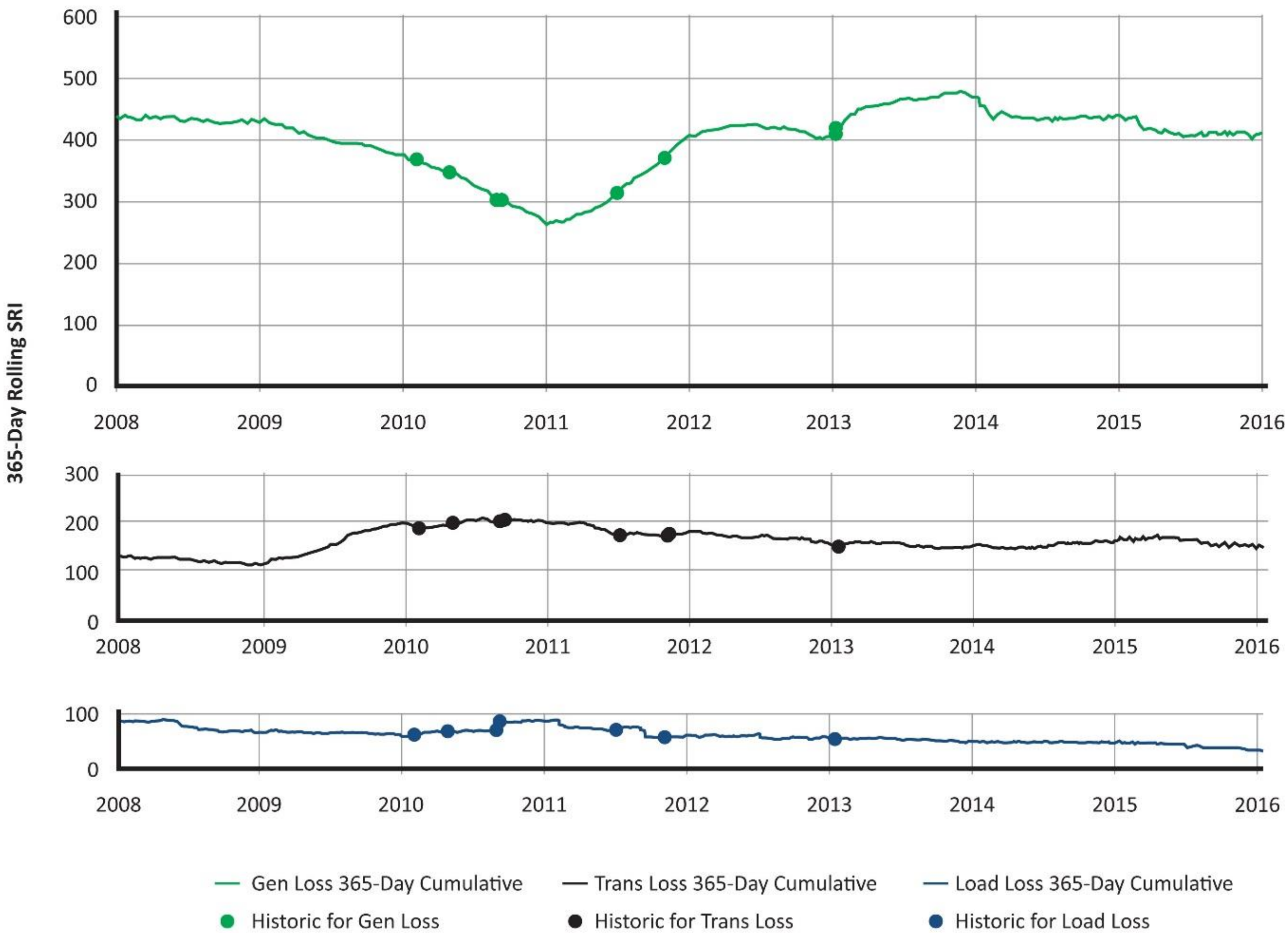


Figure 3.6: 365-day Cumulative SRI 2009–2016 by Component

Overview of TADS Analysis

TADS outage data is used to populate the transmission outage impact component of the SRI. Since transmission outages are a significant contributor to the SRI, the study of their initiating cause codes (ICCs) and sustained cause codes (SCCs) can shed light on prominent and underlying causes affecting the overall performance of the BPS. A complete analysis of TADS data is presented in Appendix B.

NERC performed six focused analytical studies of TADS data from the period 2012–2016 as follows:

1. An ICC analysis of 2012–2016 TADS outage events (momentary and sustained) for ac circuits 200 kV+
2. An ICC analysis of a subset of outage events from Study 1 that included only common/dependent mode (CDM) events with multiple transmission element outages
3. An ICC analysis of 2012–2016 TADS outage events (momentary and sustained) for ac circuits 200 kV+ by Region
4. An ICC analysis of 100 kV+ ac circuit outage events that lasted for more than a minute (defined as a sustained outage event) from 2015–2016
5. For the first time NERC analyzed by ICC 100 kV+ ac circuit and transformer sustained outage events that occurred in 2016
6. The 2015–2016 sustained ac circuit outages were analyzed by SCC

The results of these studies can be summarized with the following observations:

- The ICC Weather (excluding lightning) was a top contributor to transmission outage severity (TOS) of the 2016 sustained events for ac circuits and transformers (Study 5). From 2015 to 2016, the number of the weather-initiated momentary and sustained events of 200 kV+ ac circuits increased by 28 percent (Study 1), and the number of weather-initiated sustained events of 100 kV+ ac circuits increased by 15 percent (Study 4) while the respective TADS inventory increases were below 0.6 percent. Additionally, Weather (excluding lightning) ranks 3rd among sustained causes of ac circuit outages (Study 6).
- The ICC Unknown initiated fewer TADS events in 2016 compared with 2015: the number of Unknown momentary and sustained events of 200 kV+ ac circuits and the number of Unknown sustained events of 100 kV+ ac circuits both reduced. Moreover, from 2015 to 2016, the average transmission severity of sustained events with ICC Unknown statistically significantly reduced while the relative transmission outage risk of this ICC decreased from 16.5 percent to 12.2 percent.
- The number of combined momentary and sustained events of 200 kV+ ac circuits and sustained events of 100 kV+ circuits initiated by Misoperation increased in 2016 (Study 1 and Study 4, respectively). Relative risk of the ICC Misoperation also increased for these two datasets (Studies 1 and 4). For 2012–2016 CDM events), Misoperation is the biggest group and the top contributor to the TOS (Study 2).
- The number of TADS events initiated by Failed AC Circuit Equipment increased significantly in 2016. This was by 43 percent for combined momentary and sustained events of 200 kV+ ac circuits (Study 1) and by 23 percent for sustained events of 100 kV+ ac circuits (Study 4). Events with this ICC, on average, have a smaller TOS, but because of their high frequency of occurrence, they rank as the 3rd contributor of the TOS of sustained events of ac circuits (Study 4). Sustained outages with sustained cause code Failed AC Circuit Equipment are the largest group of ac circuit sustained outages; moreover, they have the longest duration among all sustained outages on average (Study 6).
- The number of combined momentary and sustained events of 200 kV+ ac circuits and of sustained events of 100 kV+ ac circuits both increased from 2015 to 2016, but the average TOS of an event statistically significantly decreased for both datasets (Studies 1 and 4).
- The addition of TADS transformer outages and inventory to the data for sustained events of 100 kV+ ac circuits did not significantly increase the number of events and did not lead to big changes in the ranking of ICCs by size and by relative risk, or other results of the analyses (Studies 4 and 5).

Figures 3.7 and **Figure 3.8** provide a graphic summary of Studies 1 and 4, respectively.

Figure 3.7 represents an analysis of the TOS risk of the 2012–2016 TADS events for the 200 kV+ ac circuits. The x-axis is the magnitude of the correlation of a given ICC with TOS. The y-axis represents the expected TOS of an event when it occurs. The color of the marker indicates if there is a correlation of TOS with the given ICC (positive correlation: red, negative correlation: green, or no significant correlation: blue). The size/area of the marker indicates the probability of an event initiating in any hour with a given ICC and is proportional to the number of events initiated by a given cause. For example, location and size of the Misoperation bubble in **Figure 3.7** indicates that TADS events with an ICC of Misoperation have a significant correlation between how often they will occur and their severity.

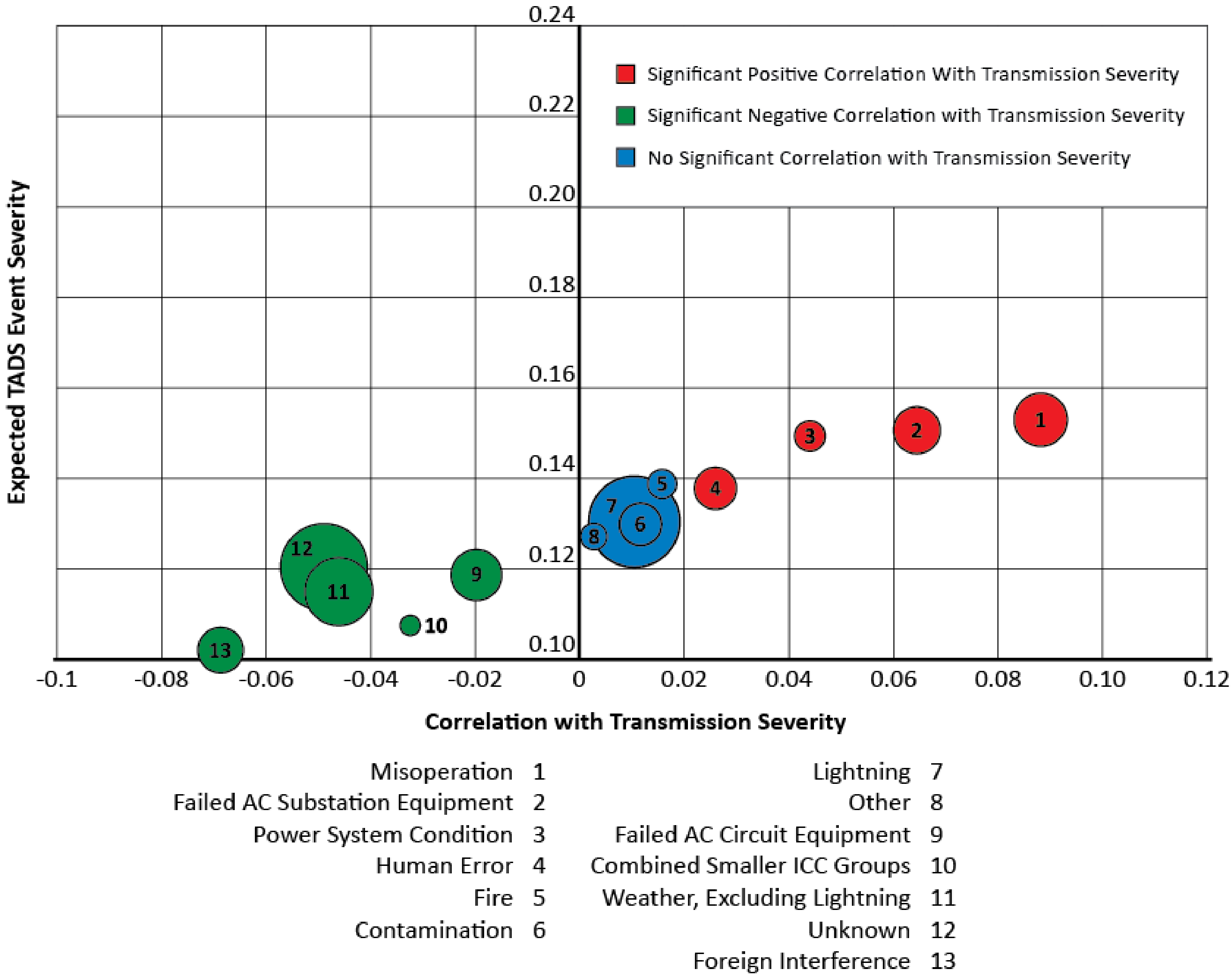


Figure 3.7: Risk Profile of 2012–2016 TADS 200 kV+ AC Circuit Events by ICC

The Misoperation ICC (which represents the TADS ICCs of Failed Protection System Equipment and Human Error associated with Misoperation) and Failed AC Substation Equipment ICC both show a statistically significant positive correlation with TOS and a higher relative transmission risk. Power System Condition, while showing a positive correlation with TOS, has a lower relative transmission risk based on the frequency of these TADS events and their expected TOS. The biggest marker (Lightning) corresponds to the biggest ICC group, which has no significant correlation with TOS but shows a high relative transmission risk because of the high probability of events initiated by lightning. The next two biggest ICC groups, Unknown, and Weather (excluding lightning), have a statistically significant negative correlation with the TOS.

Figure 3.8 represents an analysis of the TOS risk of the 2015—2016 ICC study of sustained events of 100 kV+ ac circuits in the same format. When comparing **Figure 3.7** to **Figure 3.8** (e.g., 2012–2016 TADS 200 kV+ ac circuit momentary and sustained events vs 2015–2016 100 kV+ ac circuits sustained events), 100 kV+ ac circuit sustained events with an ICC of Misoperation have decreased (while still positively correlated) in both occurrence and severity while events with an ICC of unknown have shifted from a negatively correlation between occurrence and severity to positive correlation. Misoperation, Failed AC Substation Equipment, Human Error, and Unknown show a statistically significant positive correlation with TOS and a higher relative transmission risk. Power System Condition, Contamination, and Combined Smaller ICC groups (while showing a positive correlation with TOS) have a lower relative transmission risk based on the small frequency of these events. In contrast, the biggest marker for Weather (excluding lightning) indicates the highest frequency of weather-initiated events. This leads to the highest relative risk of this group despite a lower TOS of its events.

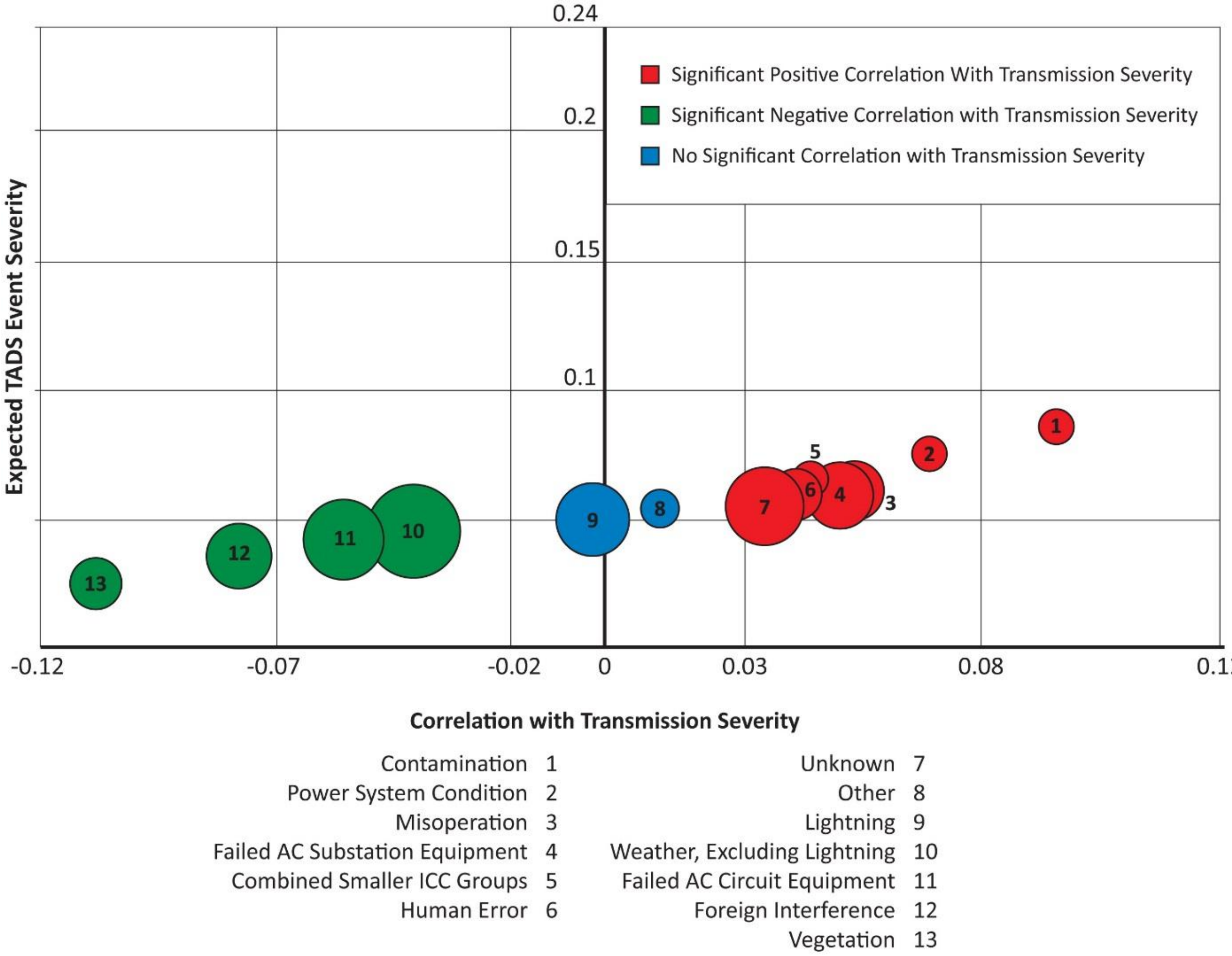


Figure 3.8: Risk Profile of the 2015–2016 Sustained Events of 100 kV+ AC Circuits by ICC

Overview of Generation Availability Data System (GADS) Data Analysis

An analysis of GADS data for calendar years 2012–2016 is presented in Appendix C. GADS outage data is used to populate the generation outage impact component of the SRI. Generation outages are a significant contributor to the 2016 SRI despite the low weighting factor assigned to the generation component. The study of their initiating causes can shed light on prominent and underlying causes affecting the overall performance of the BPS.

An analysis of the age of the existing fleet shows the following:

- An age bubble exists around 37–46 years by a population, consisting of coal and some gas units.
- A significant age bubble around 12–20 years is comprised almost exclusively of gas units.

The data set shows a clear shift toward gas-fired unit additions with the overall age of that fleet across North America being almost 10 years younger than the age of the coal-fired base-load plants that have been the backbone of power supply for many years. This trend is projected to continue given current forecasts around price and availability of natural gas as a power generation fuel as well as regulatory impetus.

GADS contains information used to compute several reliability measures, such as the weighted equivalent forced outage rate (WEFOR). WEFOR is a metric that measures the probability a unit will not be available to deliver its full capacity at any given time while taking into consideration forced outages and derates. The mean equivalent forced outage rate (EFOR) over the analysis period is 7.1 percent. EFOR has been consistent with a near-exact standard distribution.

To understand generator performance, NERC reviewed the top 10 causes of unit forced outages for the summer and winter seasons[32] as well as the annual causes for the 2012–2015 period. The analysis focused on the top causes of forced outages measured in terms of Net MWh of potential production lost. Thus, both the amount of capacity affected and the duration of the forced outages are captured.

Based on the five years of available data since GADS reporting became mandatory, the following observations can be made (as seen in **Table 3.3**):

- Severe storms in the last quarter of 2012, such as Hurricane Sandy, caused an increase in the forced outage Net MWh reported for Winter 2013.[33]
- The shoulder months of spring/fall in 2014 and 2016 have higher Net MWh attributed to forced outages than the corresponding summer or winter periods.

Table 3.3: Total Net MWh of Potential Production Lost Due to Forced Outages, by Calendar Year 2012–2016

NERC	Total Annual MWh	Summer MWh	Winter MWh	Spring/Fall MWh
2012	293,475,653	75,914,722	112,989,119	104,571,812
2013	309,011,065	83,422,362	131,422,688	94,166,015
2014	278,987,876	73,610,732	97,782,322	107,594,822
2015	251,795,168	76,955,351	88,651,639	86,188,178
2016	253,530,864	86,112,430	74,256,269	93,162,171

Overview of Demand Response Availability Data System (DADS) Analysis

In 2016, the DADS Working Group (DADSWG) continued efforts to improve data collection and reporting through outreach and development of training materials. Future DADSWG efforts are focused on improving data collection, updating existing materials and developing additional guidance documents, maintaining data quality, and providing observations of possible demand response contributions to reliability.

An analysis of DADS data from 2013 through 2016 provides the following observations:

- Over the 2013–2016 period, the total registered capacity of demand response increased slightly year-over-year in the summer reporting period (2 percent to 10 percent as reflected in Figure D.1).
- Increases in demand response enrollment in the winter reporting periods continue with a 12.7 percent increase between 2015 and 2016 (Figure D.1). This increase is due to changes in program rules and the implementation of new wholesale market demand response programs in a single Region.[34] The DADS Working Group will continue to monitor and report on trends in enrollment.

[32] Winter includes the months of December, January, and February. When analysis is performed on a calendar year basis, as for this report, these three months are included from the same calendar year. Summer includes May through September; all other months are categorized as Spring/Fall.

[33] For this analysis, the season of a forced outage is associated with the season in which the start date of the event was reported in that year; when an event continues into the next year, a new event record is created in January. This results in the event being categorized as occurring in the winter for the continuation event.

[34] This conclusion was reached through analysis of data at a nonpublic level that cannot be included in the report. The Region is not identified in the interest of assuring the protection of any reporting entity's confidentiality.

- With the exception of the summer of 2013, DADS Metric 4 reflects that the realized demand reduction rate continues to be well above 90 percent during both summer and winter periods (see Figure D.12 and Figure D.13).
- In 2016, the DADSWG did not identify any additional metrics for the data available in DADS.
- The variability at which demand response is deployed may be a function of the demand response programs' designs rather than an indication of extensive reliability issues within a Region as the SERC Region illustrates.

In **Figure 3.9**, which shows demand response events reported into DADS from January 2013 through September 2016 (grouped by month for the four years of event data), the black diamond in each column indicates the number of calendar days in a month when demand response was deployed for a reliability event. The stacked bars show the number of days that demand response events occurred in each NERC Region.[35] Note that in the SERC Region, demand response was deployed nearly every month during the analysis period, which was a function of a demand response program's design.

A complete analysis of the DADS data is presented in Appendix D.

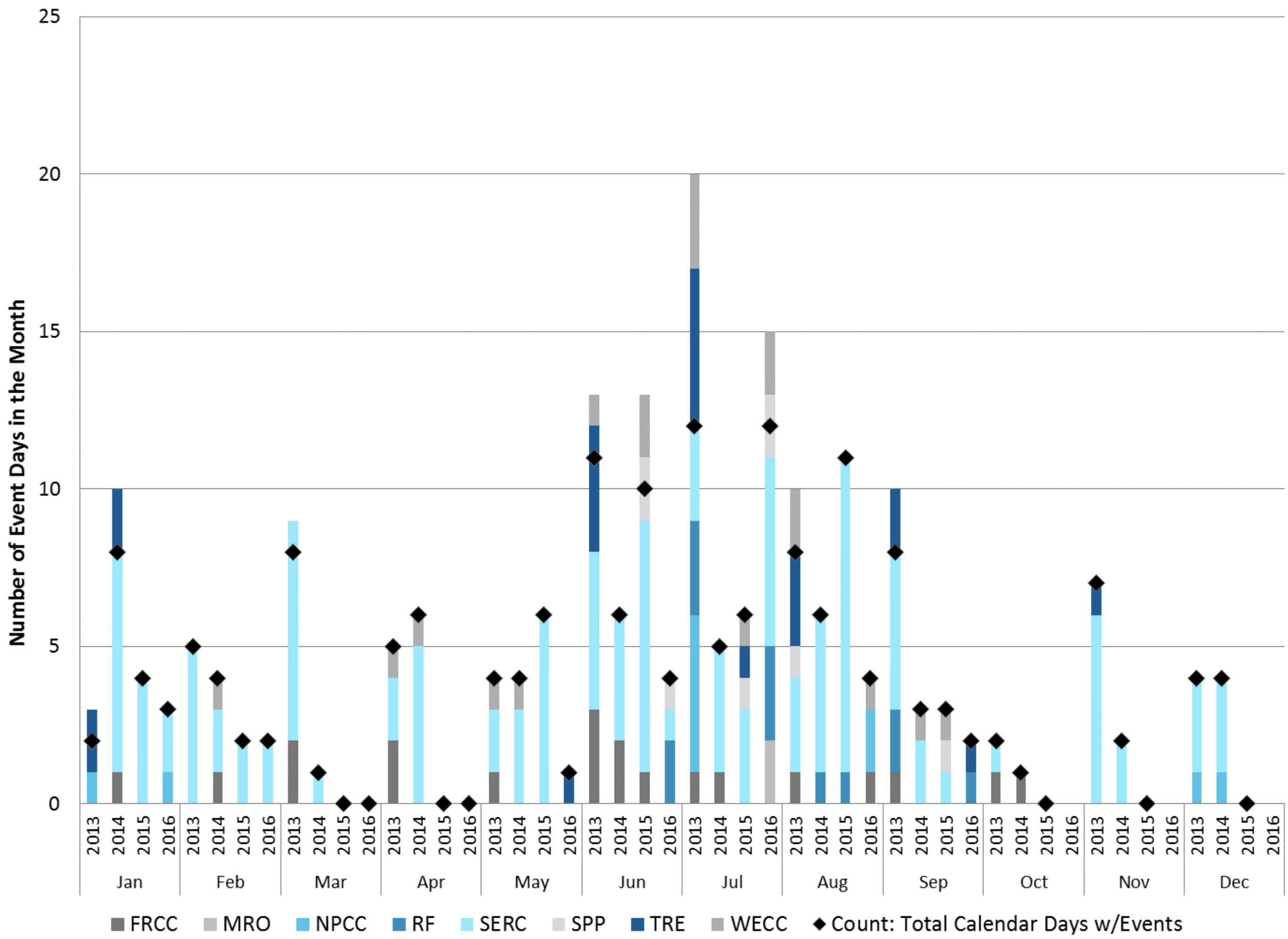


Figure 3.9: Demand Response Events by Month and Region, 2013–2016

[35] Event data for October 2016 through December 2016 is not reported until after the publication of this report.

Chapter 4: Reliability Indicator Trends

This chapter provides a summary of the reliability indicators (**Table 4.1**) and follows with a section on select metrics determined to best communicate the state of reliability in 2016, including its most challenging and improving trends and those supporting the key findings detailed in Chapter 1. Other metrics and any supporting material can be found in Appendix E. One particular metric (metric M-4, Interconnection Frequency Response) is discussed in Chapter 2 while details are explored in Appendix E.

NERC reliability indicators tie the performance of the BPS to a set of reliability performance objectives included in the approved 2012 Adequate Level of Reliability (ALR) definition.[36] This set of seven NERC reliability performance objectives are mapped to the current reliability indicators,[37] denoted as M-X, and are then evaluated to determine whether the BPS meets the ALR definition and whether overall reliability is improving or worsening. **Table 4.1** provides a summary of the trends over the past five years by providing a performance rating of improving, declining, stable, or inconclusive based on analysis of available data. “Inconclusive” is the term used when mixed results prevent determination of a trend over the analysis period.

Summary

When reviewing the reliability indicators it is important to note the following:

- **Table 4.1** lists each reliability indicator with its metric trend rating(s). Additional information for each metric can be found later in this chapter and in Appendix E.
- PAS annually reviews the reliability indicators to identify gaps in performance or data collection. Over time, PAS has implemented changes, added new indicators, and retired some indicators to keep the others relevant. An example of a recent change would be the alignment of M-12 through M-16 to the BES definition. Future developments may include the adoption of ERSWG measures[38] with near-term focus on Measure 7: Reactive Capability on the System. PAS has solicited voluntary industry data submission to support the measure, and SAMS is using this data to evaluate the measure’s value.
- Metrics are evaluated over different periods of time. This can be attributed to the period established with the approved metric definition, the duration for what data is available, or other data limitations. For example, M-4 Interconnection Frequency Response has a period defined as “1999 or when data is first available,” and M-12 has a time frame defined as “a rolling five-year average.”
- Metrics may be defined to be NERC-wide, for a specific Region, or on interconnection-level basis.
- The ALR defines the state of the BES to meet performance objectives. Reliability performance and trends of individual metrics should be evaluated within the context of the entire set of metrics.
- It is important to retain the anonymity of individual reporting entities when compiling the data necessary to evaluate metric performance. Details presented in this report are aggregated to maintain the anonymity of individual reporting organizations.

[36] Definition of “Adequate Level of Reliability”: http://www.nerc.com/comm/Other/Adequate%20Level%20of%20Reliability%20Task%20Force%20%20ALRTF%20DL/Final%20Documents%20Posted%20for%20Stakeholders%20and%20Board%20of%20Trustee%20Review/2013_03_26_ALR_Definition_clean.pdf

[37] http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2014_SOR_Final.pdf

[38] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

Table 4.1: Metric Trends		
Metric	**Description**	**Trend Rating**
M-1	Planning Reserve Margin	Stable—Appendix E
M-2	BPS Transmission-Related Events Resulting in Loss of Load (modified in early 2014)	Improving
M-3	System Voltage Performance (discontinued in 2014)	Retired—Appendix E
M-4	Interconnection Frequency Response	Eastern—Improving—Appendix E
		ERCOT—Improving—Appendix E
		Western—Improving—Appendix E
		Québec—Stable—Appendix E
M-5	Activation of Underfrequency Load Shedding (discontinued in 2014)	Retired
M-6	Average Percent Nonrecovery Disturbance Control Standard Events	Stable
M-7	Disturbance Control Events Greater than Most Severe Single Contingency	Stable
M-8	Interconnected Reliability Operating Limit/System Operating Limit (IROL/SOL) Exceedances (modified in 2013)	Eastern—Inconclusive—Appendix E
		ERCOT—Stable—Appendix E
		Western—Stable—Appendix E
		Québec—Retired—Appendix E
M-9	Correct Protection System Operations	Improving
M-10	Transmission Constraint Mitigation (discontinued in 2016)	Retired
M-11	Energy Emergency Alerts (modified in 2013)	Inconclusive
M-12	Automatic AC Transmission Outages Initiated by Failed Protection System Equipment (modified in late 2014)	Circuits—Improving
		Transformers—Improving
M-13	Automatic AC Transmission Outages Initiated by Human Error (modified in late 2014)	Circuits—Inconclusive
		Transformers—Improving
M-14	Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment (modified in late 2014)	Circuits—Stable
		Transformer—Improving
M-15	Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment (modified in late 2014; normalized by line length)	Declining
M-16	Element Availability Percentage (APC) and Unavailability Percentage (modified in 2013)	Circuits—Inconclusive
		Transformers—Improving

M-2 BPS Transmission-Related Events Resulting in Loss of Load

Background

This metric measures BPS transmission-related events that result in the loss of load, excluding weather-related outages. The underlying data that is used for this metric is important for operators and planners in assessing how effective their design and operating criteria are.

Consistent with the revised metric approved by the OC and PC in March 2014, an "event" is an unplanned disturbance that produces an abnormal system condition due to equipment failures/system operational actions (either intentional or unintentional) that result in the loss of firm system demands. This is identified by using the subset of data provided in accordance with Reliability Standard EOP-004-2.[39] The reporting criteria for such events, beginning with data for events occurring in 2013, are as follows:[40]

1. The loss of firm load for 15 minutes or more:
   - 300 MW or more for entities with previous year's demand of 3,000 MW or more
   - 200 MW or more for all other entities
2. A BES emergency that requires manual firm load shedding of 100 MW or more
3. A BES emergency that resulted in automatic firm load shedding of 100 MW or more (via automatic undervoltage or underfrequency load shedding schemes, or special protection systems (SPSs)/remedial action schemes (RASs)
4. A transmission loss event with an unexpected loss within an entity's area, contrary to design, of three or more BES elements caused by a common disturbance (excluding successful automatic reclosing) resulting in a firm load loss of 50 MW or more

PAS reviewed this M-2 metric in 2013 and made changes to its criteria to increase consistency with EOP-004-2 criteria for reporting transmission-related events that result in loss of load. The criteria presented above were approved for implementation in the first quarter of 2014. Changes in the annual measurement between 2012 and 2013 therefore reflect the addition of Criteria 4, which has been applied to the data since 2013. For the first part of the analysis below, shown in **Figure 4.1** and **Figure 4.2**, historical data back to 2002 was used and the new Criteria 4 was not included to allow trending of the other aspects of the metric over time. **Figure 4.3** includes all of the criteria, so it was only evaluated for 2013–2016: the time period for which data collection associated with the new criteria was available. The performance trend is continuing to improve.

Assessment

Figure 4.1 shows the number of BPS transmission-related events that resulted in the loss of firm load from 2002–2016. On average, just under eight events were experienced per year. The BPS experienced four transmission load loss events in 2016. This continues a mixed but improved trend since 2012 in the number of events.

Figure 4.2 indicates that the top three years in terms of load loss remain 2003, 2008, and 2011 due to the major loss-of-load events that occurred. In 2003 and 2011, one event accounted for over two-thirds of the total load loss, while in 2008, a single event accounted for over one-third of the total load loss.

Load loss excluding Criteria 4 is less for 2016 than for any year since 2002 inclusive. Load loss over the last four years remains below the median value. This also continues a mixed, but improved, trend since 2011 in the total annual load loss from these events.

[39] http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-2.pdf

[40] http://www.nerc.com/comm/PC/Performance%20Analysis%20Subcommittee%20PAS%202013/ALR1-4_Revised.pdf

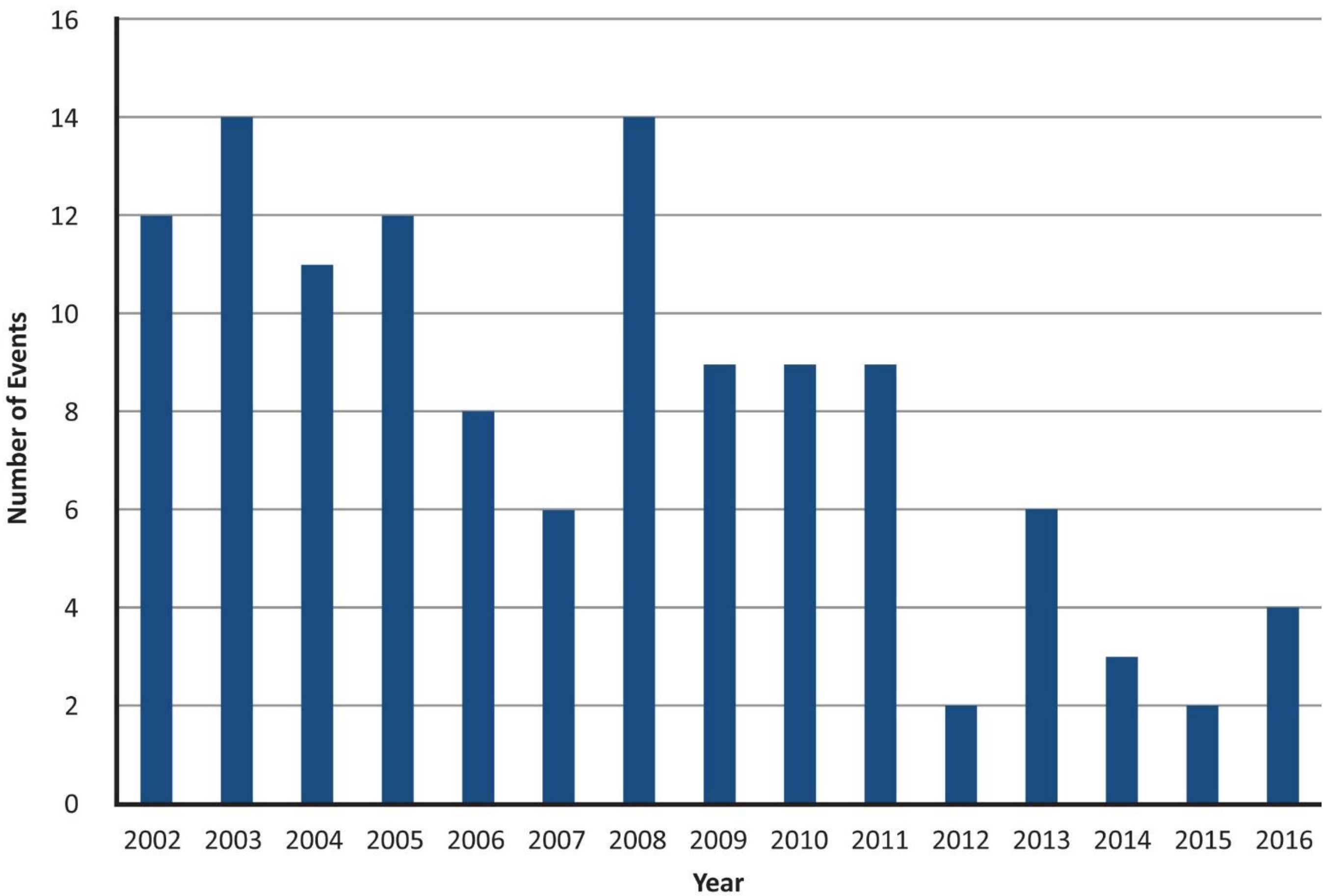


Figure 4.1: M-2 BPS Transmission Related Events Resulting in Load Loss (Excluding Criteria 4)

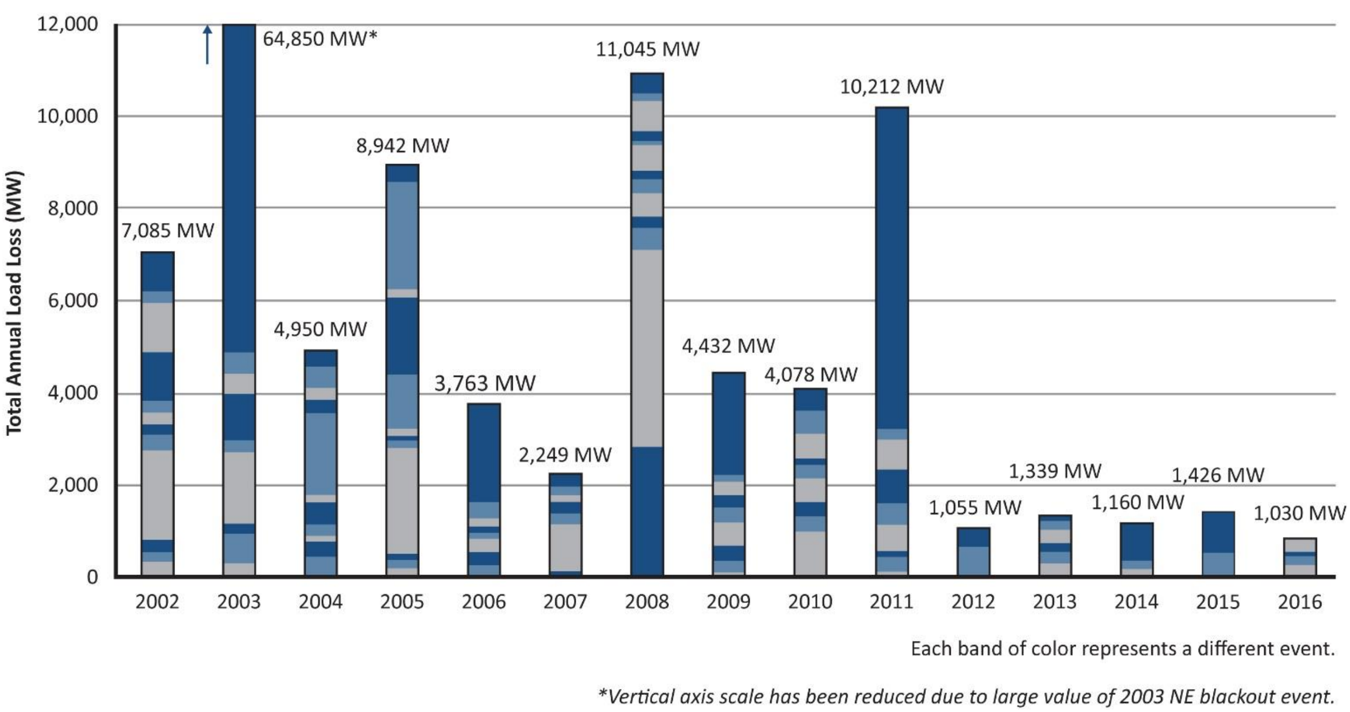


Figure 4.2: M-2 BPS Transmission-Related Events Resulting in Load Loss (Excluding Criteria 4)

Figure 4.3 shows the number of events resulting in firm load loss of 50 MW or greater from 2013–2016 and their durations. The metric was modified in 2013 to include Criteria 4 events. There were 14 events during 2016 (10 under Criteria 4. See **Figure 4.2**) with load loss of ≥ 50MW. For 2016 the largest number of load loss events was once again in the category of less than one hour in duration.

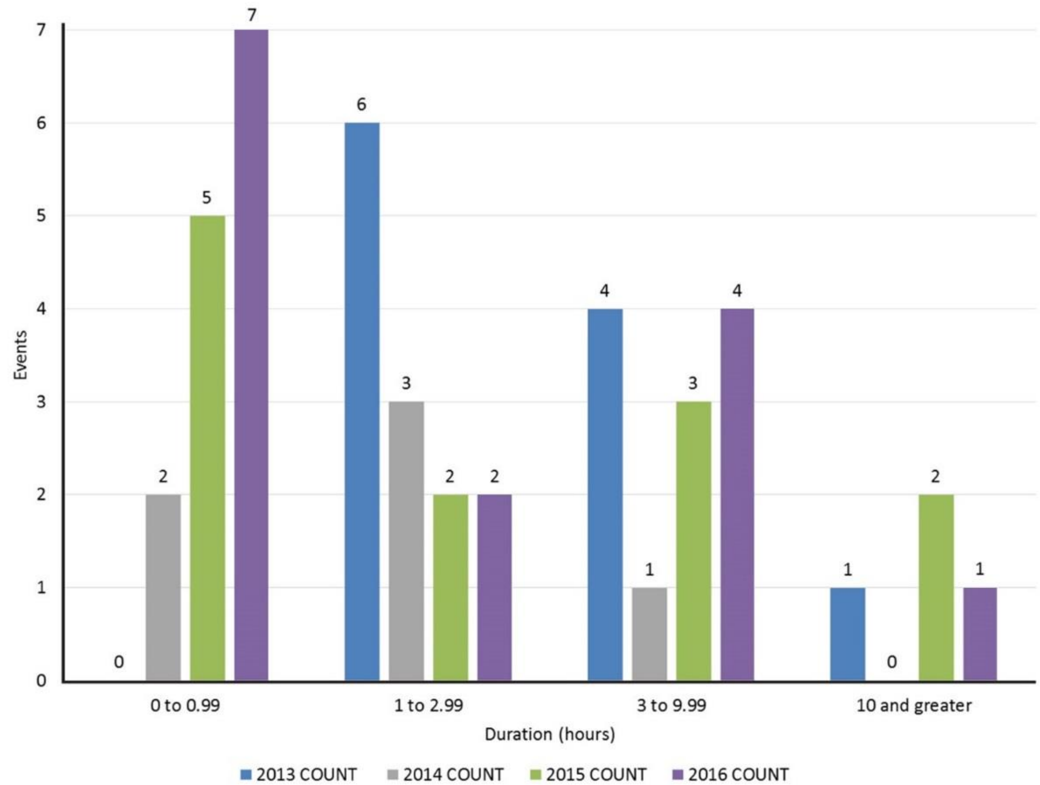


Figure 4.3: Outage Duration vs. Events

The major significance of this metric is found in the detailed data that supports the Criteria 4 events captured in **Figure 4.3** that cannot be shared in this report in an attributable form due to confidentiality requirements. The initiating cause and, where applicable, the contributing factor(s) of these 10 events support the message of the other metrics in this chapter and validate the approaches in use by NERC and the entire ERO Enterprise. These are listed in **Table 4.2**.

Table 4.2: 2016 Criteria 4 Initiating Cause and Contributing Cause(s)		
Event Number	**Initiating Cause**	**Contributing Factor(s)**
1	Circuit Equipment Failure	
2	Protection System Misoperation	
3	Circuit Equipment Failure	
4	Protection system Misoperation	
5	Human Error	Misoperation

Table 4.2: 2016 Criteria 4 Initiating Cause and Contributing Cause(s)		
Event Number	**Initiating Cause**	**Contributing Factor(s)**
6	Circuit Equipment Failure	
7	Circuit Equipment Failure	Misoperation
8	Protection System Misoperation	Circuit Equipment Failure
9	Circuit Equipment Failure	Protection System Misoperation
10	Circuit Equipment Failure	Protection System Misoperation

Of the 10 events, six have the initiating cause of Circuit Equipment Failure, three with the contributing factor of Misoperation; three have the initiating cause of Protection System Misoperation, one of these with the contributing factor of Circuit Equipment Failure; and one of these has the initiating cause of Human Error with the contributing factor of Misoperation.

M-9 Correct Protection System Operations

Background

The correct protection system operations metric demonstrates the performance of protection systems (both generator and transmission) on the BPS. The metric is the ratio of correct protection system operations to total system protection system operations.

Protection system misoperations have been identified as a major area of concern as stated in previous *State of Reliability* reports. Improvements to data collection that the System Protection Control Subcommittee (SPCS) proposed were implemented as a result.[41] NERC coordinates with each Region as well as these groups to continue the focus on improvements. Both correct operations and misoperations are including in the reporting below.

Assessment

Figure 4.4 shows the total correct operations rate for NERC through the first three reporting quarters of 2016.

[41]http://www.nerc.com/comm/PC/Protection%20System%20Misoperations%20Task%20Force%20PSMTF%202/PSMTF_Report.pdf

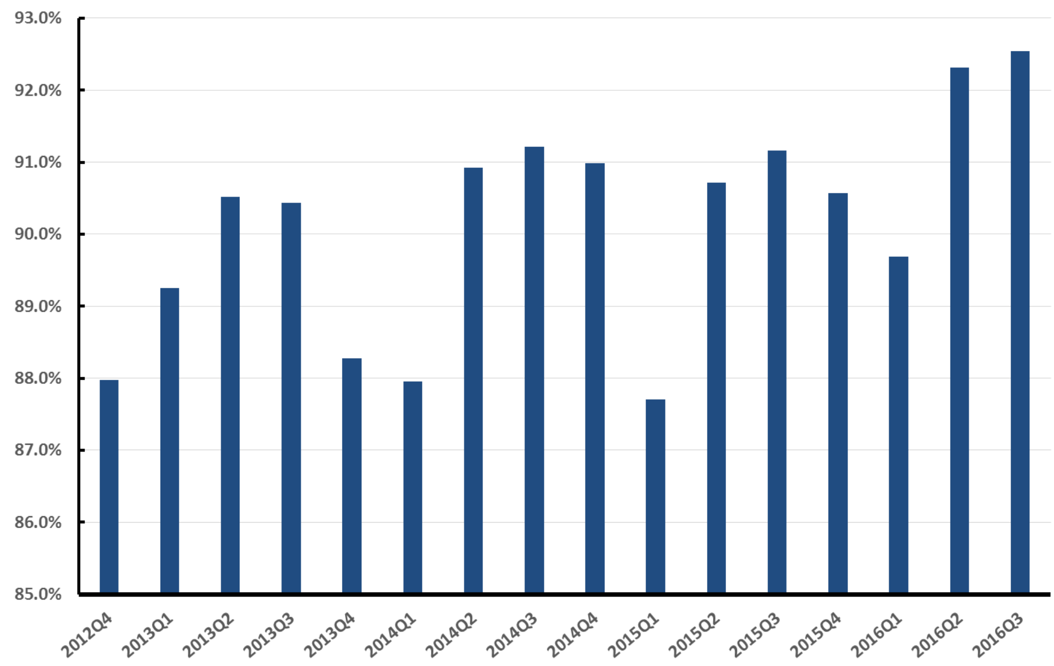


Figure 4.4: Correct Protection System Operations Rate

Figure 4.5 shows the regional misoperation rates and summarizes results of the statistical tests[42] on misoperation rate comparisons. The dark blue bars show the rates that are statistically significantly higher than NERC's rate of 9.5 percent, as shown in Table E.24, and the light blue bars correspond to the rates significantly lower than NERC's rate. NPCC's rate was calculated based on the Q1 2013–Q3 2016 data. WECC's rate was calculated based on Q2 and Q3 2016 data when they became available.

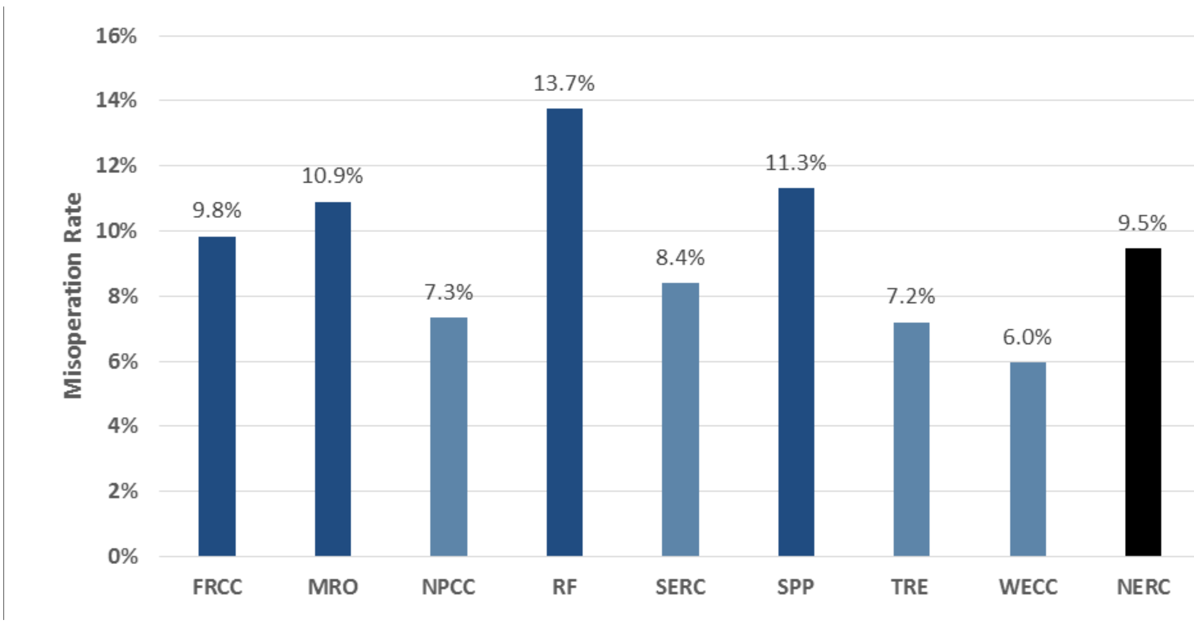


Figure 4.5: Four-Year Misoperation Rate by Region (Q4 2012–Q3 2016)

[42] Large sample test on population proportions at the 0.05 significance level

Year-Over-Year Changes by Region

Changes from the first four quarters (Q4 2012–Q3 2013, Year 1) to the second four quarters (Q4 2013–Q3 2014, Year 2) to the third four quarters (Q4 2014–Q3 2015, Year 3) to the fourth four quarters (Q4 2015–Q3 2016, Year 4) were studied to compare time periods with similar composition of seasons.[43] For Year 4, the misoperation rate is calculated in two ways: 1) with all Regions (excluding WECC) and 2) with WECC misoperation and operation counts included for Q2 and Q3 2016. The changes are shown in **Figure 4.6**.

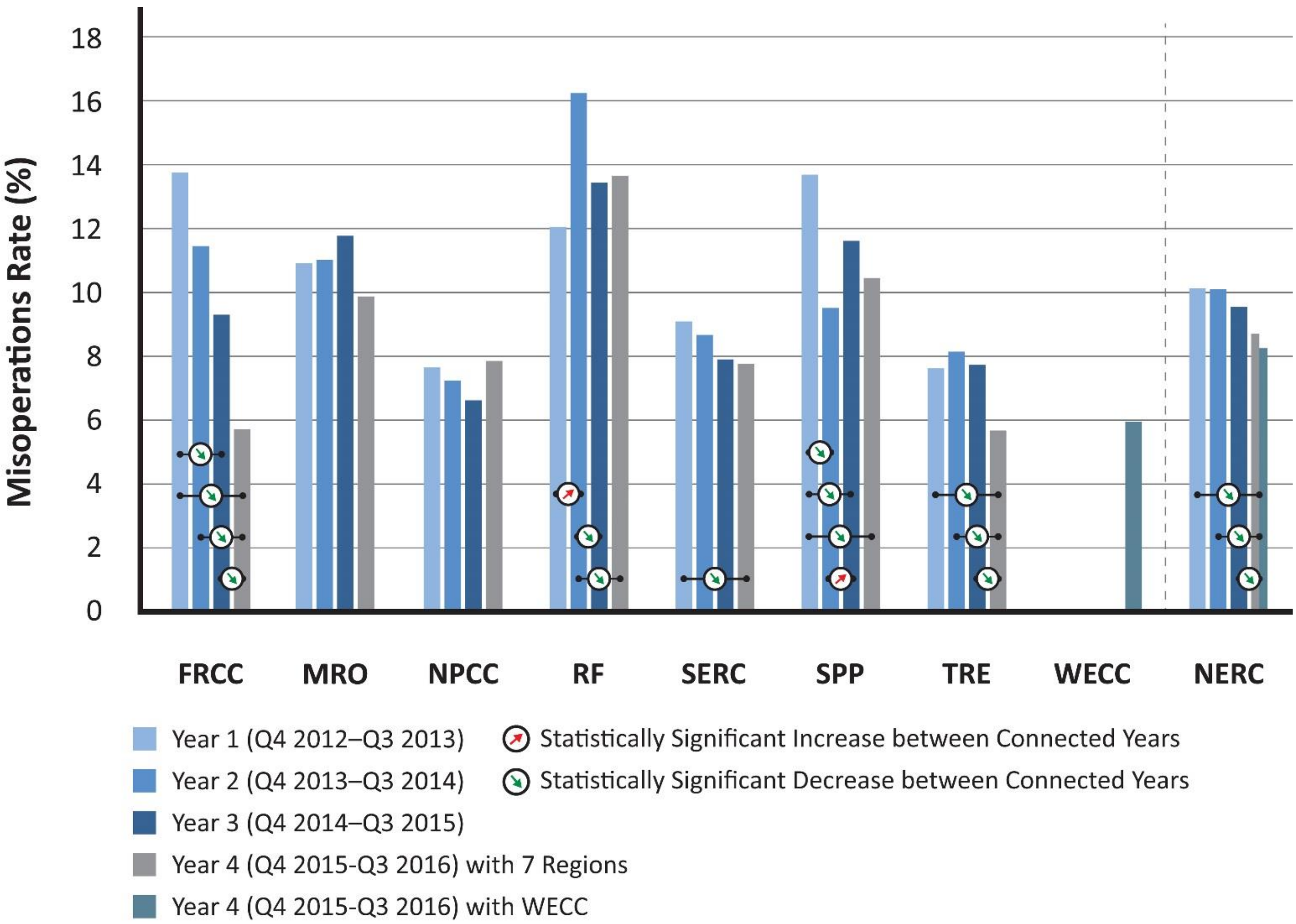


Figure 4.6 Year-Over-Year Changes in Misoperation Rate by Region and NERC

In **Figure 4.6**, Regions are listed alphabetically from left to right with the total misoperation rate for NERC on the far right. Tests[44] on misoperation rates found the statistically significant year-to-year changes shown in **Figure 4.6** by arrows. Red arrows signify increased rates and green arrows signify decreased rates.

Table 4.3 lists the Regional misoperation rates that are shown graphically in **Figure 4.6**.

[43] Year-over-year changes in historical rates shown in this report reflect improvements in data quality resulting from the standardization and automation of the collection of protection system operations and misoperations data in 2016.

[44] Large sample test on population proportions at the 0.05 significance level

Table 4.3: Misoperation Rate by Region and NERC—by Year					
Region	**Year 1 (Q4 2012-Q3 2013)**	**Year 2 (Q4 2013-Q3 2014)**	**Year 3 (Q4 2014-Q3 2015)**	**Year 4 (Q4 2015-Q3 2016, 7 Regions)**	**Year 4 (Q4 2015-Q3 2016, Last 2 Quarters with WECC)**
FRCC	13.7%	11.4%	9.3%	5.7%	5.7%
MRO	10.9%	11.0%	11.8%	9.9%	9.9%
NPCC (Q1 2013 to Q3 2016)	7.7%	7.2%	6.6%	7.9%	7.9%
RF	12.1%	16.2%	13.4%	13.6%	13.6%
SERC	9.1%	8.7%	7.9%	7.8%	7.8%
SPP	13.7%	9.5%	11.6%	10.4%	10.4%
TRE	7.6%	8.2%	7.7%	5.7%	5.7%
WECC (Q2 and Q3 2016 only)					6.0%
NERC	**10.2%**	**10.1%**	**9.5%**	**8.7%**	**8.3%**

In **Figure 4.7**, Regions are listed alphabetically from left to right with the total NERC rate on the far right of the combined misoperation rate of the top three causes of misoperations (Incorrect Settings/Logic/Design Errors, Relay Failures/Malfunctions, and Communication Failures) for the four years.

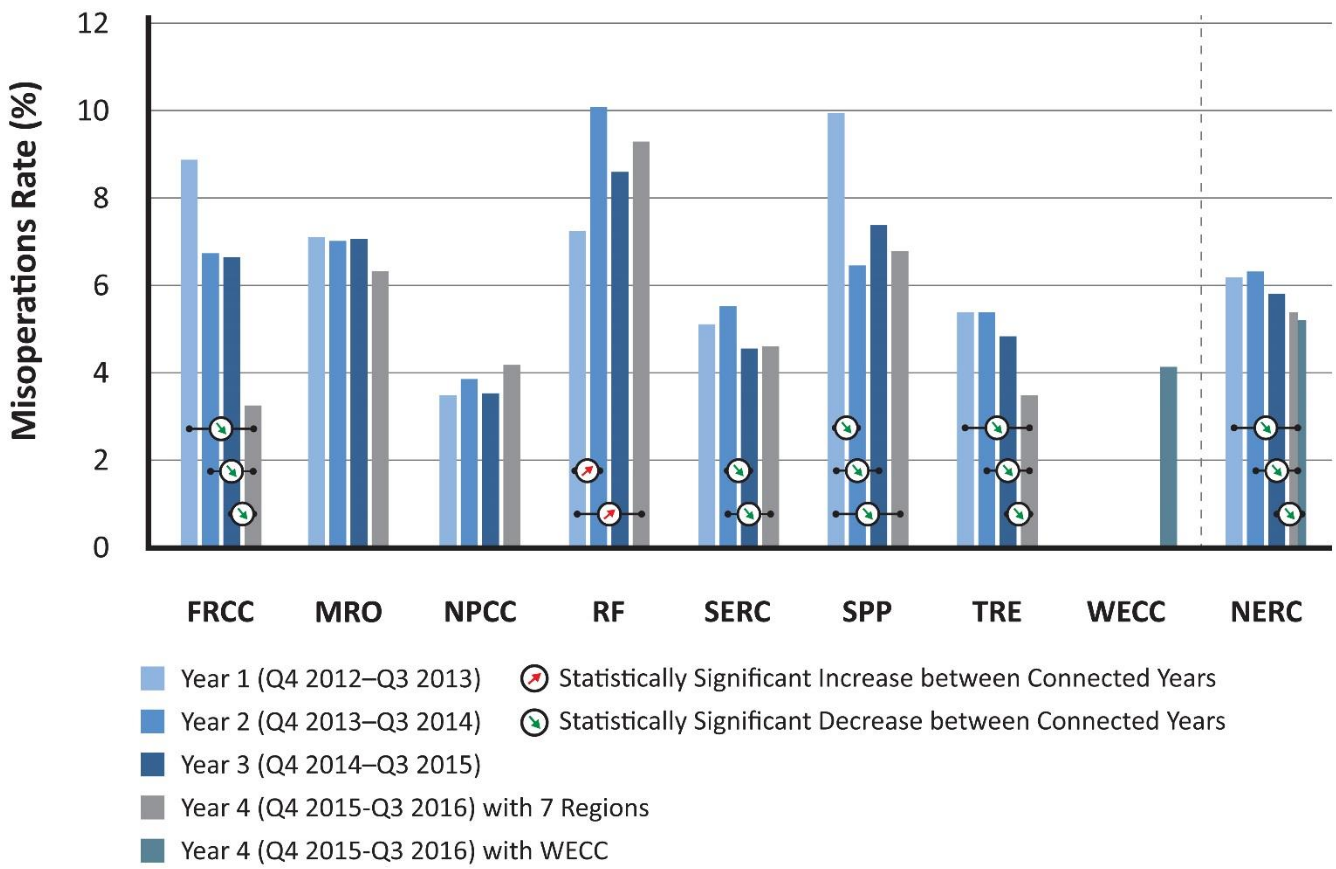


Figure 4.7: Year-Over-Year Changes in Misoperation Rate for Top Three Causes by Region and NERC

Tests[45] on misoperation rates for the top three causes combined found the statistically significant year-to-year changes shown in **Figure 4.7** by arrows. Red arrows signify increased rates and green arrows signify decreased rates. These observations confirm an improving performance of M-9.

Actions to Address Misoperations

NERC is revising a number of Reliability Standards that involve protection systems.[46] To increase awareness and transparency, NERC will continue to conduct industry webinars[47] on protection systems and document success stories on how entities achieve higher levels of protection system performance. The quarterly protection system misoperation trends of NERC and the REs can be viewed on NERC's website.[48]

In addition, NERC and Regional staff have again analyzed the top three protection system misoperation cause codes reported by the Regions and NERC through compliance with Reliability Standard PRC-004-2.1a to identify RE trends and provide guidance to protection system owners that experience a high number of misoperations.[49] Incorrect Setting/Logic/Design Errors was found to still be the largest source of misoperations in almost every Region. This supports the focus on setting/logic/design controls, and REs are also pursuing targets specific to each Region's own results. NERC and Regional staff also updated the reporting template to separate the "Incorrect Setting/Logic/Design Errors" into "Incorrect Settings," "Logic Errors," and "Design Errors" to provide more granular information for their mitigation. NERC and industry actions identified in the report are expected to result in a statistically significant reduction in the rate of misoperations due to these causes by the end of 2017.

The ERO Enterprise determined from EA data and from industry expertise that a sustained focus on education regarding the instantaneous ground overcurrent protection function and on improving relay system commissioning tests were actionable and could have a significant effect. The relay ground function accounted for 11 misoperations in 2014, causing events that were analyzed due to voluntary entity reporting and cooperation. That was reduced to six event-related misoperations in 2015, and further reduced to one event-related operation in 2016. Similarly, one Region experienced a statistical improvement in relay misoperations from 2013–2014 and maintained this performance through 2016. This performance followed Regional efforts that targeted a reduction of communication failures.

Based on the statistically significant increase in the total correct operation rate and the reduction in NERC's misoperation rate from 9.5 percent in 2015 to 8.7 percent in 2016, the performance trend for this metric is considered to be improving. Further statistical analysis can be found in Appendix E.

M-12 through M-14 Automatic AC Transmission Outages

Background

These metrics measure the impacts of Failed Protection System, Human Error, and Failed AC Substation Equipment respectively as factors in the performance of the ac transmission system. The metrics use the TADS data and definitions. The metrics were enhanced in 2014 and 2015 to be consistent with the collection of BES data in TADS and to align with the definition of the BES and include some equipment to 100 kV.[50] With the revisions, the metrics include any BES ac transmission element outages that were initiated by the following:

- M-12: TADS Initiating Cause Code (ICC) of Failed Protection System Equipment
- M-13: TADS Initiating Cause Code (ICC) of Human Error

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[45] Large sample test on population proportions at the 0.05 significance level
[46] http://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx
[47] http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf
[48] http://www.nerc.com/pa/RAPA/ri/Pages/ProtectionSystemMisoperations.aspx
[49] http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/NERC Staff Analysis of Reported Misoperations - Final.pdf
[50] http://www.nerc.com/pa/RAPA/Pages/BES.aspx

- M-14: TADS Initiating Cause Code (ICC) of Failed AC Substation Equipment

Each metric is calculated for ac circuits and transformers separately in sub-metrics as follows:

- The continued normalized count (on a per circuit basis) of 200 kV+ AC transmission element outages (i.e., TADS momentary and sustained automatic outages) that were initiated by Failed Protection System Equipment, Human Error, or Failed AC Substation Equipment.
- Beginning January 1, 2015, the normalized count (on a per circuit basis) of 100 kV+ AC transmission element outages (i.e., TADS sustained automatic outages) that were initiated by Failed Protection System Equipment, Human Error, or Failed AC Substation Equipment.

Assessment M-12 through M-14 AC Circuit Outages

Changes of the metrics by year are shown in **Figures 4.8** through **Figure 4.10** which present the ac circuit outages two sub-metrics: 1) the annual frequency of automatic outages per 200 kV+ ac circuit, for the time period 2012–2016, and 2) the annual frequency of sustained automatic outages per 100 kV+ ac circuit, for the time period 2015–2016.

Overall, the performance of M-12 through M-14 ac circuit outages is inconsistent. There is improved performance of M-12 in ac circuits Failed Protection System Equipment; however, M-12 had no significant change from 2015–2016. Performance of M-13 for ac circuits Human Errors was inconsistent. M-13 had a significant increase from 2015–2016. M-14 for ac circuits Failed Protection System Equipment had stable performance, yet M-14 had no significant change from 2015–2016.

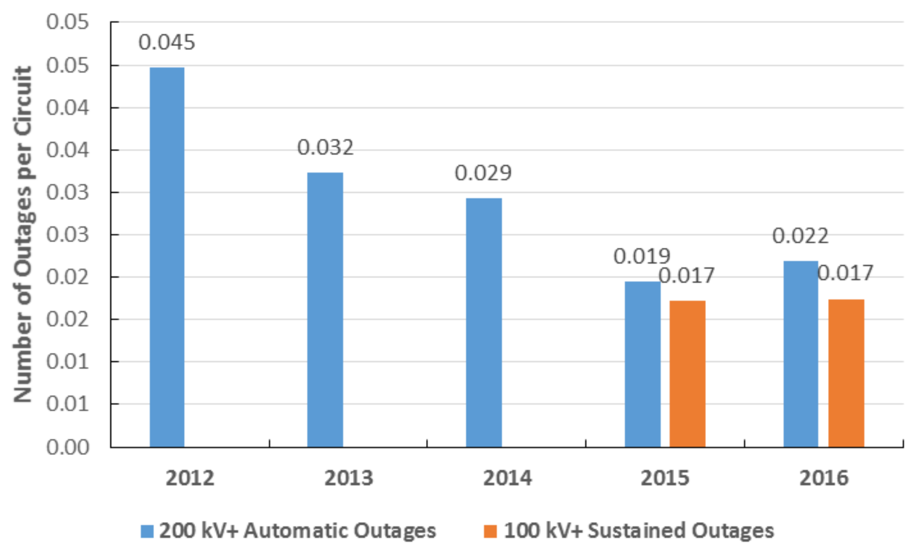

Figure 4.8: AC Circuit Outages Initiated by Failed Protection System Equipment (M-12)

The calculated annual outage frequencies, per ac circuit, were tested to identify significant year-to-year changes of the reliability metric. Below is a summary of M-12 performance for the five years:

- Statistically significant decrease from 2012–2013 and from 2014–2015
- No significant changes from 2013–2014 and from 2015–2016
- The 2016 outage frequency is significantly lower than in each year from 2012–2014

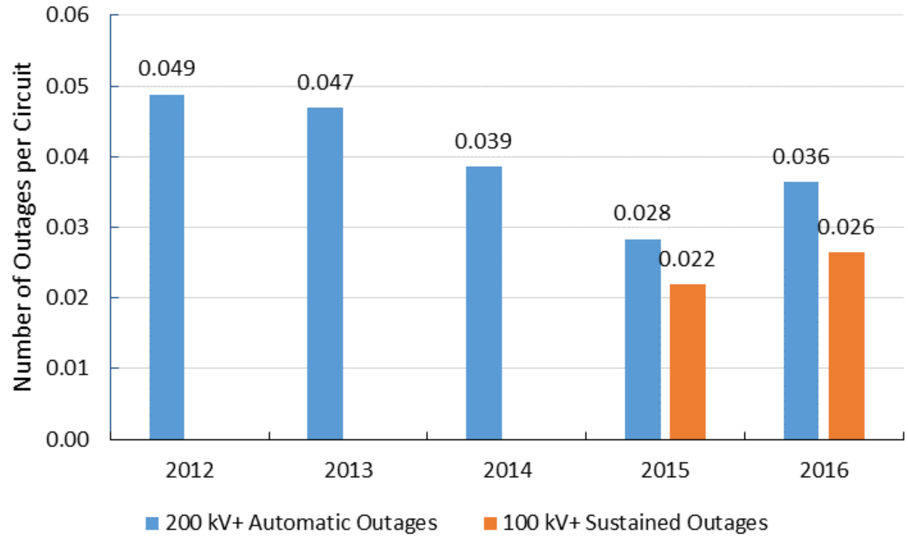

Figure 4.9: AC Circuit Outages Initiated by Human Error (M-13)

The calculated annual outage frequencies per ac circuit were tested to identify significant year-to-year changes of the reliability metric. Below is a summary of M-13 performance for the five years:

- Year-to-year decreases from 2012–2014 with no statistically significant changes from 2012–2013 and from 2013–2014
- Statistically significant decrease from 2014–2015
- Statistically significant increase from 2015–2016
- The 2016 outage frequency is statistically significantly lower than in each year from 2012–2013

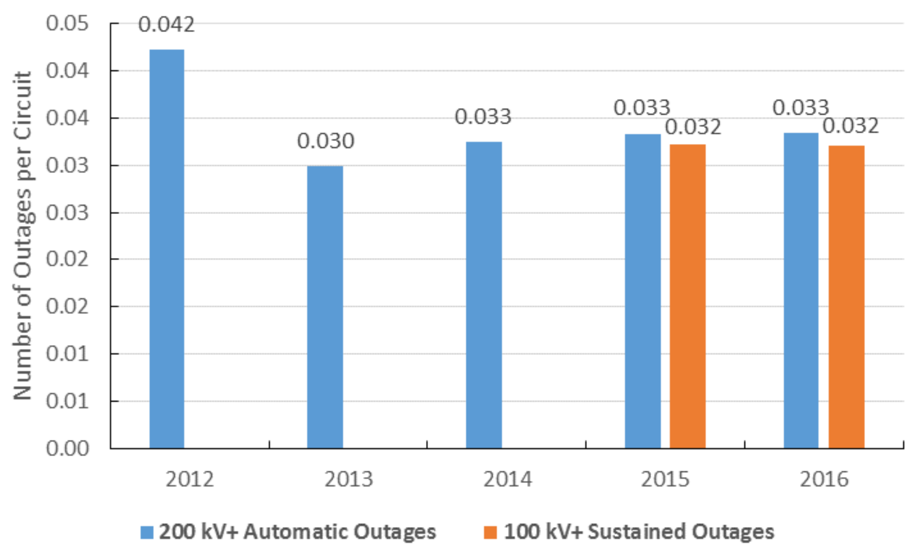

Figure 4.10: AC Circuit Outages Initiated by Failed AC Substation Equipment (M-14)

The calculated annual outage frequencies per ac circuit were tested to identify statistically significant year-to-year changes of the reliability metric. Below is a summary of M-14 performance for the five years:

- Statistically significant decrease from 2012–2013

- No statistically significant changes from 2013–2014, from 2014–2015, and from 2015–2016
- The 2016 outage frequency is significantly lower than in 2012

Assessment M-12 through M-14 Transformer Outages

Changes of the metrics by year are shown in **Figures 4.11** through **Figure 4.13** which present the transformer outages sub-metrics as follows: 1) the annual frequency of automatic outages per 200 kV+ transformer for the time period 2012–2016, and 2) the annual frequency of sustained automatic outages per 100 kV+ transformer for the time period 2015–2016.

Overall, the performance of M-12 through M-14 transformer outages is improving. Performance of M-12 for Transformers Failed Protection Equipment is improving while M-12 had no significant change from 2015–2016. Observations confirm a stable performance for the five years and an improved performance since 2013 of M-13 for Transformer Human Error, and M-13 had no significant change from 2015–2016. Performance of M-14 for Transformer Failed AC Substation Equipment has improved, and M-14 had no significant change from 2015–2016.

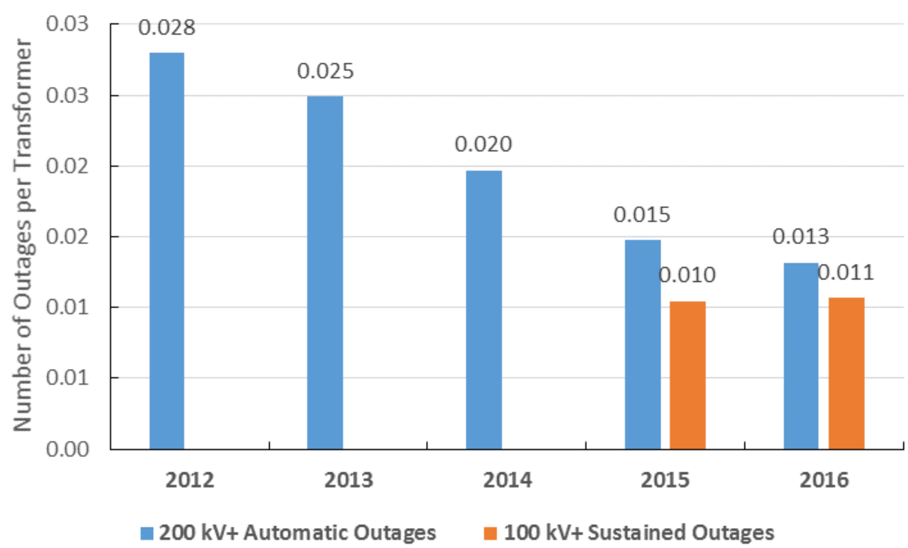

Figure 4.11: Transformer Outages Initiated by Failed Protection System Equipment (M-12)

The calculated annual outage frequencies per transformer were tested to identify significant year-to-year changes of the reliability metric. Below is a summary of M-12 performance for the five years:

- Year-to-year decreases from 2012–2015 with no statistically significant changes for any pair of consecutive years
- The 2016 outage frequency is lower than in each year from 2012–2015 and statistically significantly lower than in 2012–2013

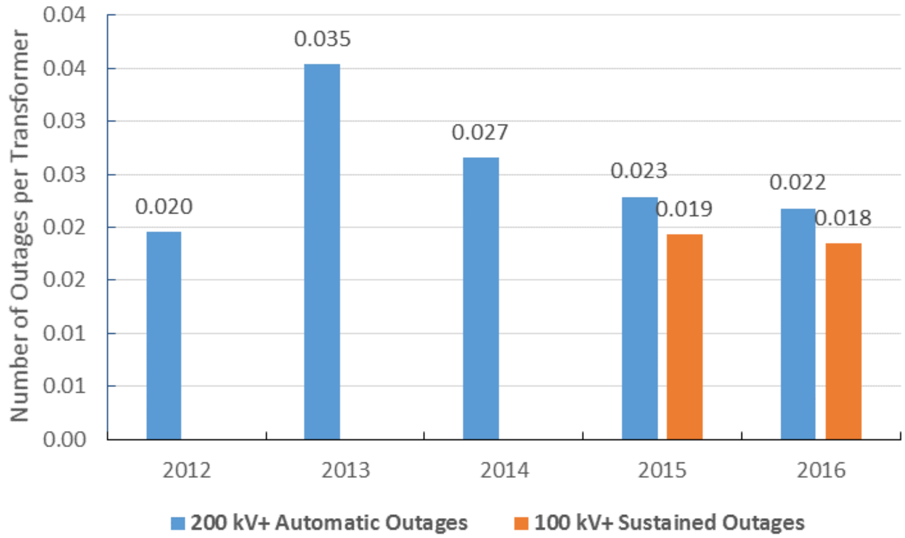

Figure 4.12: Transformer Outages Initiated by Human Error (M-13)

The calculated annual outage frequencies per transformer were tested to identify statistically significant year-to-year changes of the reliability metric. Below is a summary of M-13 performance for the five years:

- Annual decreases from 2013–2016
- Statistically significant decrease from 2013–2015
- The 2016 outage frequency is lower than in 2013, 2014, and 2015 and statistically significantly lower than in 2013

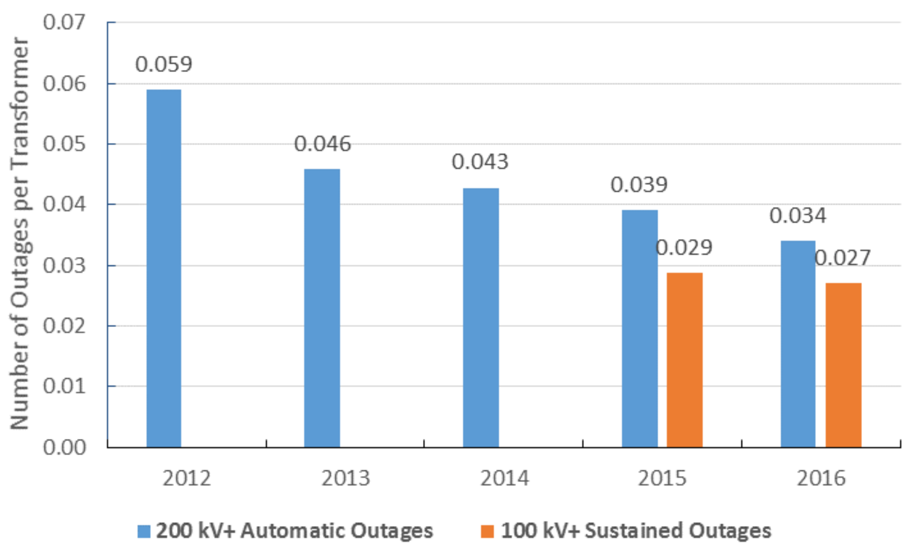

Figure 4.13: Transformer Outages Initiated by Failed AC Substation Equipment (M-14)

The calculated annual outage frequencies per transformer were tested to identify significant year-to-year changes of the reliability metric. Below is a summary of M-14 performance for the five years:

- Year-to-year decreases from 2012–2016 with no significant changes between any two consecutive years
- The 2016 outage frequency is lower than in any other year and statistically significantly lower than in 2012

M-15 Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment

Background

This metric measures the impact of Failed AC Circuit Equipment as one of many factors in the performance of ac transmission systems. Metric M-15 follows the same methodology described for M-12 through M-14 except that it uses a normalization based on a line length and is defined for ac circuits only. As with M-12 through M-14 the sub-metrics are calculated as follows:

- The continued normalized count (on a per 100 circuit-mile basis) of 200 kV+ ac transmission circuit outages (i.e., TADS momentary and sustained automatic outages) initiated by Failed AC Circuit Equipment
- Beginning January 1, 2015, the normalized count (on a 100 per circuit-mile basis) of 100 kV+ ac transmission circuit outages (i.e., TADS sustained automatic outages) initiated by Failed AC Circuit Equipment

Assessment

Changes of M-15 by year are shown in **Figure 4.14**. **Figure 4.14** presents M-15 (blue), the annual frequency of automatic outages per hundred miles for ac circuits of 200 kV+, for the time period 2012–2016 and M-15 (orange), the annual frequency of sustained automatic outages per hundred miles for ac circuits of 100 kV+, for the time period 2015–2016.

For the years 2012–2016, M-15 performance was declining, demonstrated by an increase in outage frequency. This is also seen in M-15 from 2015–2016.

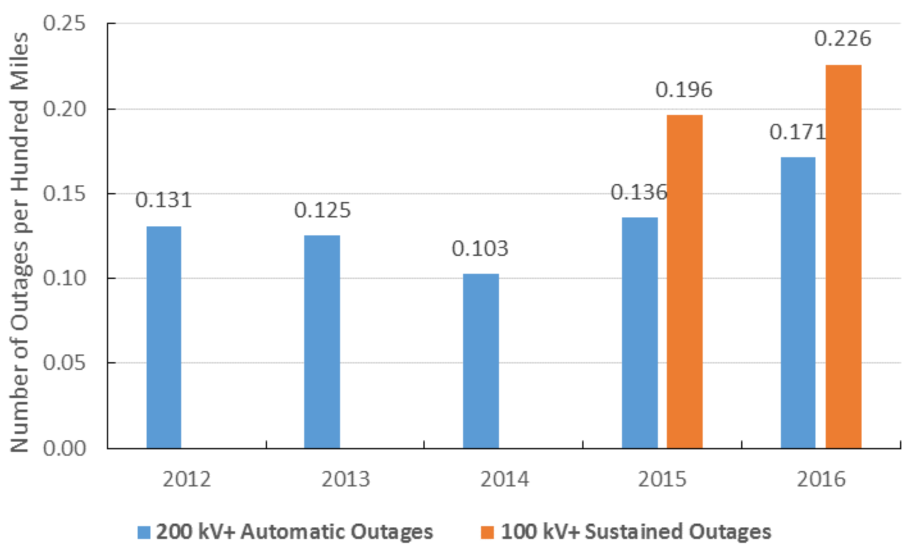

Figure 4.14: AC Circuit Outages Initiated by Failed AC Circuit Equipment

The observed changes in the calculated frequencies cannot be statistically analyzed due to a mile-based normalization (these numbers do not represent observations in a statistical sample) and can be only compared numerically. The annual outage frequencies per hundred-mile ac circuit decreased every year from 2012–2014 and then increased in 2015 and again in 2016. The 2016 frequency was the largest after 2011.

M-16 Element Availability Percentage and Unavailability Percentage

Background

The element availability percentage (APC) and unavailability percentage metric determines the percentage of BES ac transmission elements that are available or unavailable when outages due to automatic and nonautomatic events are considered.

Originally, there were two metrics: one to calculate availability and one to calculate unavailability, but these were combined into one metric in 2013. This metric continues to focus on availability of elements at 200 kV+ because the components of the calculation included planned outages (these are no longer collected in TADS since 2015), unplanned outages (these are collected in TADS for all BES elements), and operational outages (these are only collected in TADS for 200 kV+). Therefore, the reporting voltage levels for this metric did not change.

Assessment

For both transmission element types, ac circuits, and transformers, only charts for unavailability are shown because annual unavailability can be broken down by outage type (unlike availability). This is important since a part of unavailability due to planned outages is shown for 2012–2014 and removed for 2015–2016 due to changes in TADS data collection.

Figure 4.15 presents 200 kV+ ac circuit unavailability as a percentage for the time period 2012–2016. Note that in 2015–2016 unavailability due to planned outages is removed from the definition and calculation. In 2012–2013, this portion of unavailability was the largest of the three.

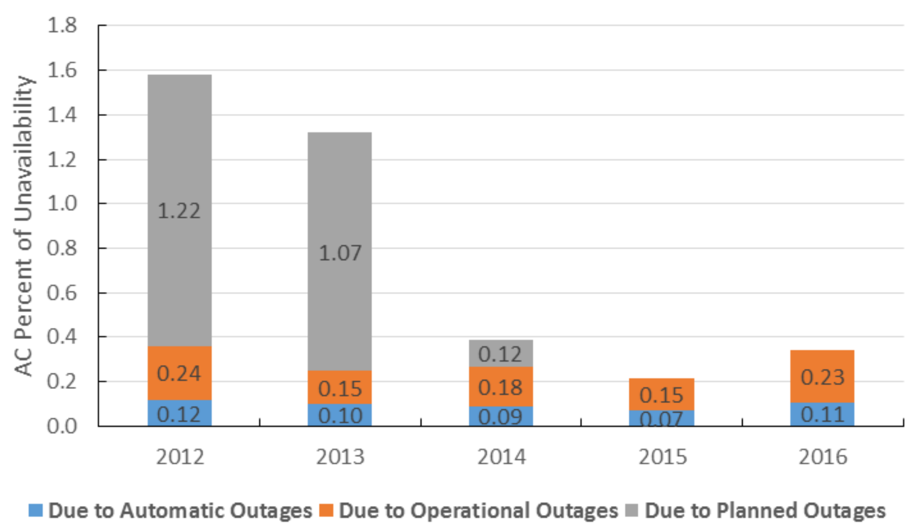

Figure 4.15: AC Circuit Unavailability by Year and Outage Type

The ac circuit combined unavailability, due to operational and automatic outages in 2016, was the second largest from 2012–2016.

Figure 4.16 presents 200 kV+ TADS transformer unavailability as a percentage for the time period 2012–2016. Since 2015, unavailability due to planned outages has been removed from the definition and calculation. In 2012–2014, this portion of unavailability was the largest of the three.

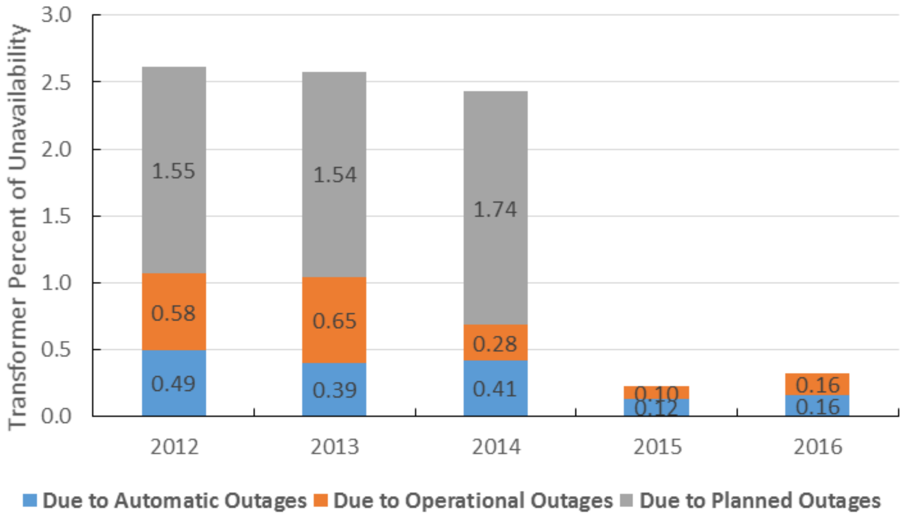

Figure 4.16: Transformer Unavailability by Year and Outage Type

Transformer unavailability due to operational and automatic outages in 2016 was the second lowest from 2012 to 2016.

The performance trend of M-16 for ac circuits is inconclusive and for transformers is considered to be improving. It is worth noting that a sizable change in transformer inventory occurred in 2015 due to changes in TADS reporting and that additional year-over-year data will be needed before drawing definite conclusions.

Chapter 5: Enforcement Metrics for Risk and Reliability Impact

The Compliance and Certification Committee (CCC) and PAS developed two compliance-based metrics with a focus on compliance violation's risk to and impact upon the BPS. When reviewing the enforcement metrics, it is important to keep the following considerations in mind:

- A violation that could create a potentially serious risk to reliability may not have an actual impact on reliability.
- A violation that results in some adverse impact to the BPS may not have created a serious risk to reliability.
- Not all incidents on the BPS are the results of violations of a Reliability Standard.

The ERO Enterprise assesses and handles violations as the noncompliance is identified by registered entities and RE compliance monitoring activities. With the RE's implementation of risk-based compliance monitoring and enforcement, the REs can focus their review on serious-risk violations. Some serious-risk violations occurring prior to 2016 are yet to be fully investigated and filed with FERC. As the REs conclude the investigation and mitigation of those serious-risk violations and NERC files notices of penalty (NOPs) with FERC, the counts of serious-risk violations reported in this chapter may increase.

CP-1: Risk Metric

Compliance Process-1 (CP-1) is a quarterly count of violations[51] determined to have posed a serious risk to the reliability of the BPS.[52] This metric tracks serious-risk violations based on the quarter when the violations occurred.

Figure 5.1 depicts the number of and the trend in serious-risk violations that have completed the enforcement process since the start of mandatory compliance with Reliability Standards in 2007. The rolling average provides an indicator of whether the rate of serious-risk violations is increasing, decreasing, or remaining steady.

[51] NERC provides this information on a quarterly basis at: http://www.nerc.com/pa/comp/CE/Pages/Compliance-Violation-Statistics.aspx
[52] Information on risk assessment of noncompliance is available at: http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/ERO%20Self-Report%20User%20Guide%20(April%202014).pdf

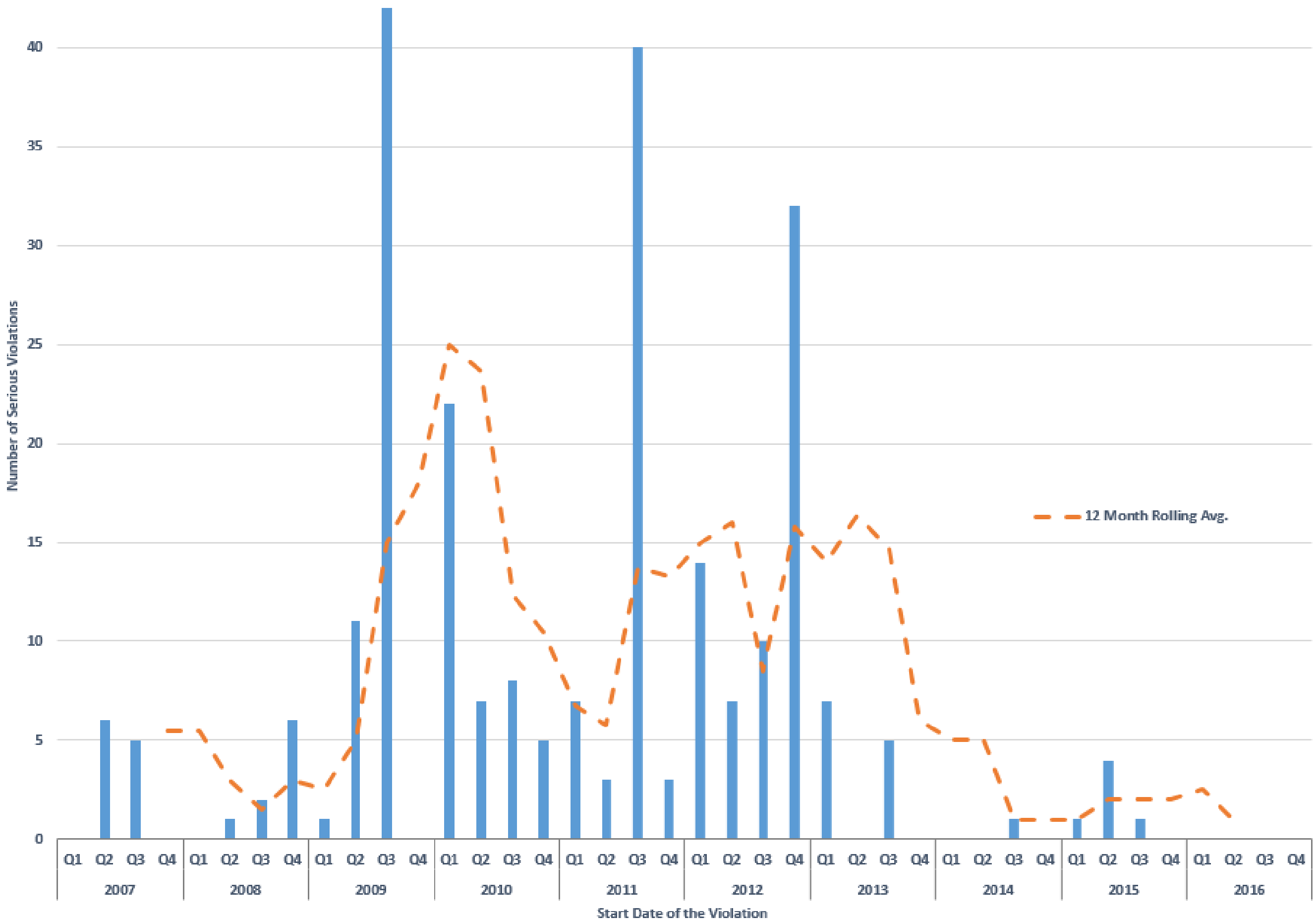

Figure 5.1: Serious-Risk Violations (CP-1)

Serious-risk-based violations have remained below the rolling average except in four instances as follows: The spikes in the third quarter of 2009 and the first quarter of 2010 are largely attributable to the implementation of the Critical Infrastructure Protection (CIP) Reliability Standards as they became applicable to additional registered entities. The spike in the third quarter of 2011 is largely attributable to the September 8, 2011, Southwest Outage and the resulting violations resolved through FERC/NERC investigations. The last spike in the fourth quarter of 2012 is related to a large number of serious CIP violations.

While it appears that there is a decreasing trend in the 12 month rolling average of serious risk violations, it is important to remember that there is time required to fully understand serious risk violations and reach disposition, which may include the filing of a full NOP. NERC and RE representatives have analyzed serious risk violations from 2012 through the end of 2015. In the future, there may be additional serious risk violation added to the count of this metric as reported violations are fully analyzed and reach disposition.

Figure 5.2 depicts the top 10 standards and requirements that were filed at FERC as serious-risk violations since 2012.[53] NERC posts all NOP on its website to provide information to industry about how to reduce the frequency of noncompliance and its associated risk.[54]

[53] With CIP Version 5 and revisions to the IRO/TOP Standards, the requirement numbers have changed, but most of the substantive requirements remain.

[54] The Enforcement page is here: http://www.nerc.com/pa/comp/CE/Pages/Enforcement-and-Mitigation.aspx The Searchable Notice of Penalty Spreadsheet available on that page indicates the risk assessments for all violations included in Notices of Penalty.

The serious risk issues addressed in NOPs in 2016 included the following:

- A lack of commitment to NERC compliance regarding CIP Reliability Standards
- Vegetation contacts
- Repeat conduct
- Ineffective change management including employee turnover
- Lack of preparedness for the interconnection of new facilities and the enforceability of new requirements and
- Inadequate training of personnel on tools and processes

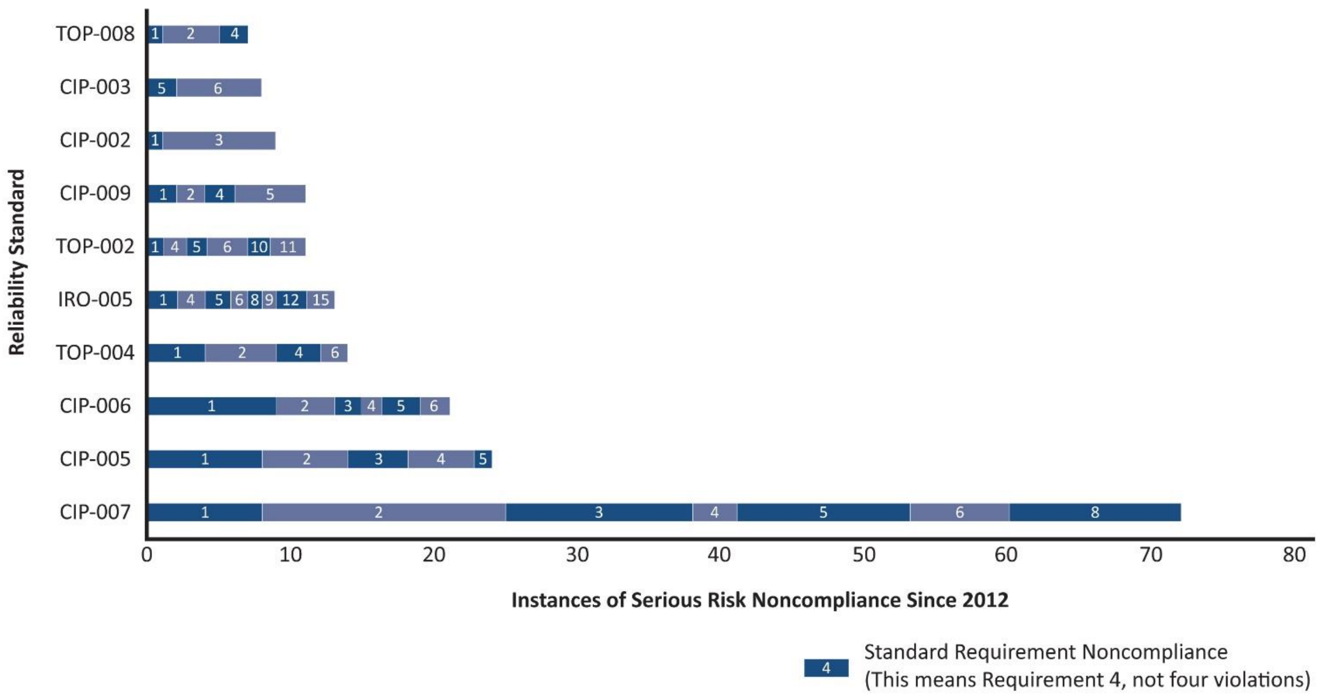

Figure 5.2: Standards and Requirements with Most Occurrences of Serious-Risk Violations

Figure 5.3 shows the risk breakdown of violations processed from 2013 to 2016. A small percentage of violations were deemed to have the potential to create a serious risk. Risk assessments result from evaluation of the possible impact of a noncompliance and the likelihood of occurrence of that impact. CP-1 is a measure of potential risk and not of actual impact. CP-2 considers the impact of an occurrence of noncompliance.

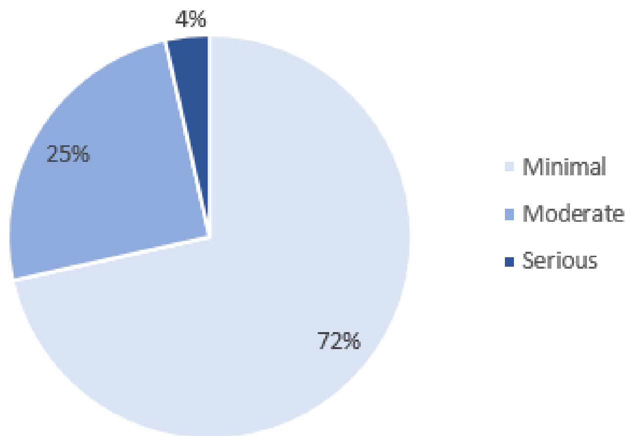

Figure 5.3: Final Risk Assessments (2013–2016)

CP-2: Impact Metric

In addition to analysis of noncompliance occurrences that have a potential for serious risk to the BPS, NERC also evaluates whether these instance have an actual impact on reliability as a result and looks for trends in what requirements are being violated that produce negative reliability impacts. Compliance Process-2 (CP-2) is a quarterly count of the number of noncompliance incidents with observed reliability impact regardless of the risk assessment. This metric is based on what happened because of a specific instance of noncompliance. **Figure 5.4** maps the four data tiers that define the impacts used for CP-2 with Tier 3 being the most serious.

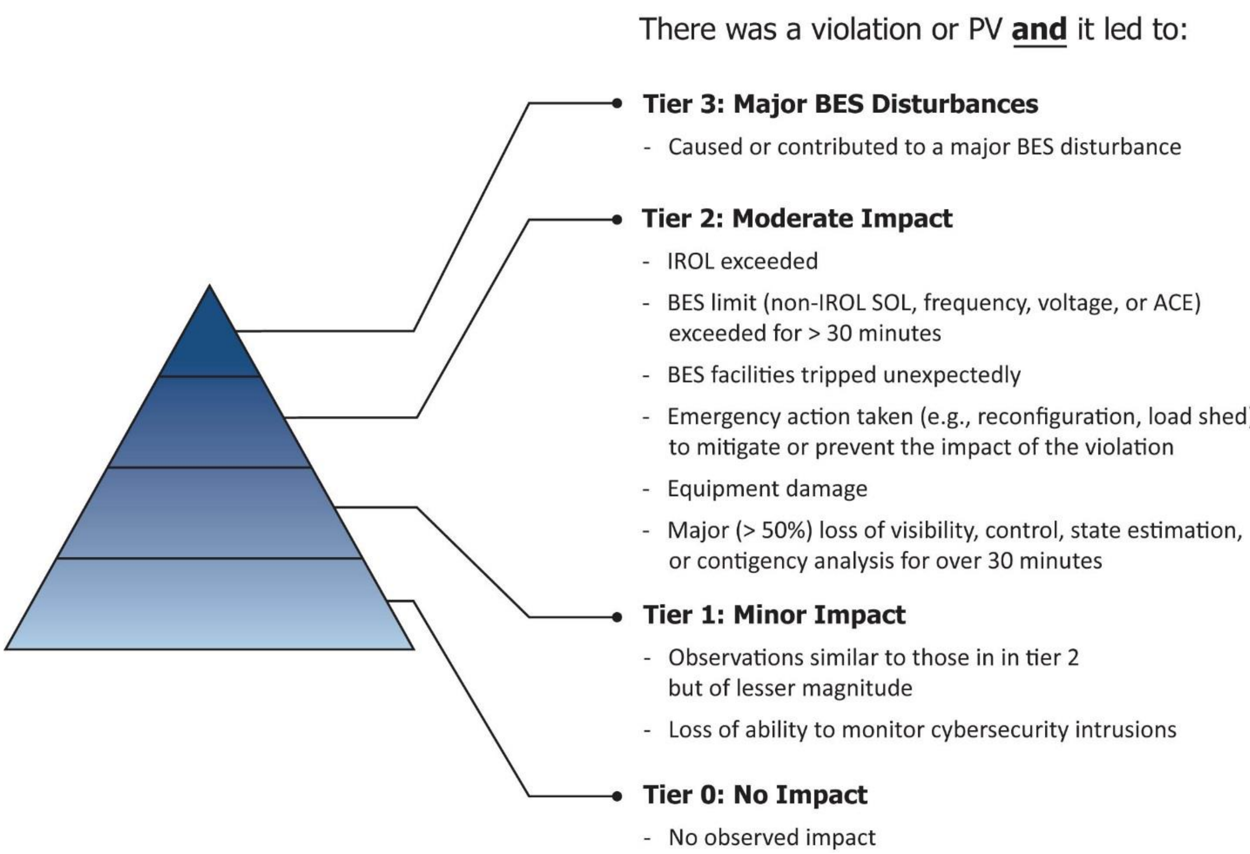

Figure 5.4: Impact Observations Mapped to the Impact Pyramid Tiers

Tier 0 observations represent the largest number of violations with no observable impact to BPS reliability.

Figure 5.5 represents the occurrence dates of the violations filed since 2014 that had some observed impact on reliability.[55] Tier 0 observations (no observed impact) are not depicted. The moving averages provide an indicator of whether the rate of impactful violations is increasing, decreasing, or remaining steady.

As in the CP-1 graph, **Figure 5.5** displays a spike in violations with impact in the third quarter of 2011 because of the Southwest Outage that occurred on September 8, 2011. The spike in the third quarter of 2012 is attributable to violations by WECC RC, now Peak Reliability, that are described in a March 31, 2014, NOP filing with FERC.[56] As with the trend in CP-1, the number of violations with impact remains constant at a relatively low level. However, as not all reported noncompliances have reached final disposition, this metric is also subject to change.

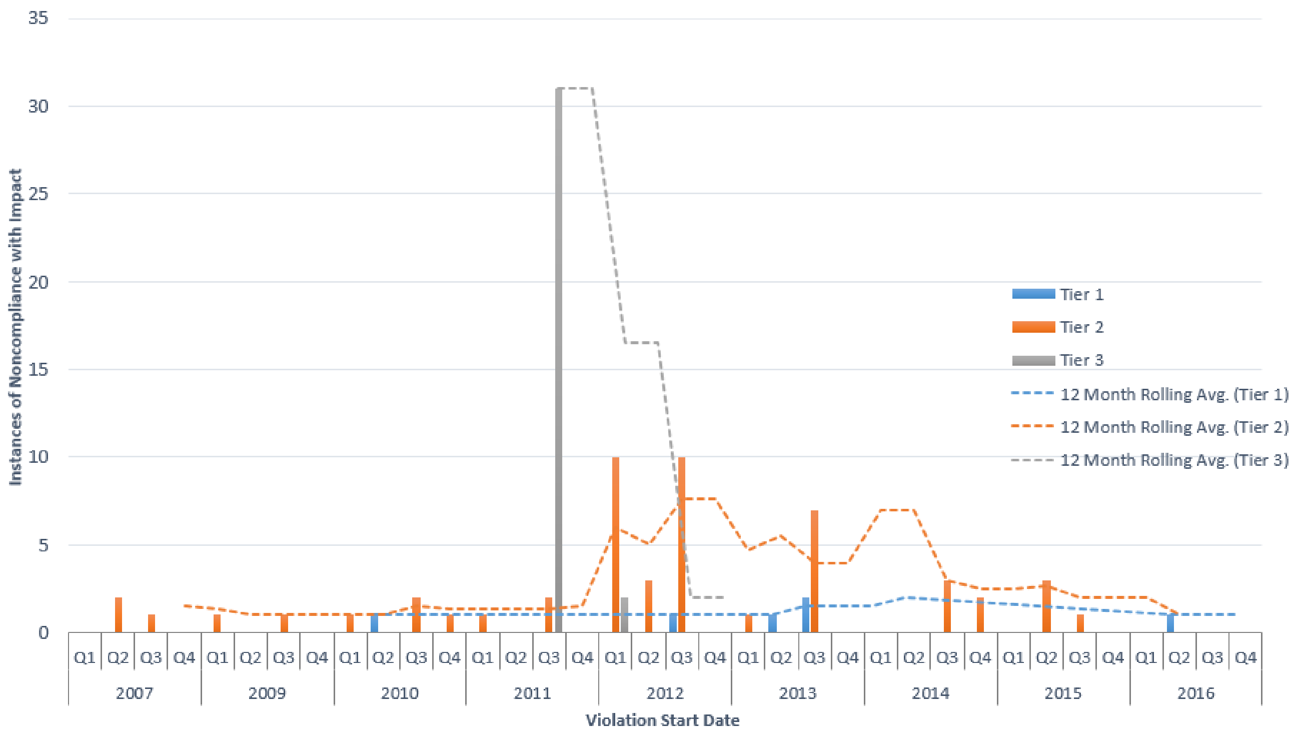

Figure 5.5: CP-2 Occurrences (2014–2016 Data)

Figure 5.6 shows the breakdown by requirement of the most frequently impactful noncompliance filed in 2014 through 2016.

The IRO and Transmission Operator (TOP) requirements represented in **Figure 5.6** correspond to the serious-risk violations associated with the Southwest Outage and the WECC RC NOP referenced previously.

[55] NERC provides this information on a quarterly basis at: http://www.nerc.com/pa/comp/CE/Pages/Compliance-Violation-Statistics.aspx
[56] http://www.nerc.com/pa/comp/CE/Enforcement%20Actions%20DL/Public_FinalFiled_NOP_NOC-2268.pdf

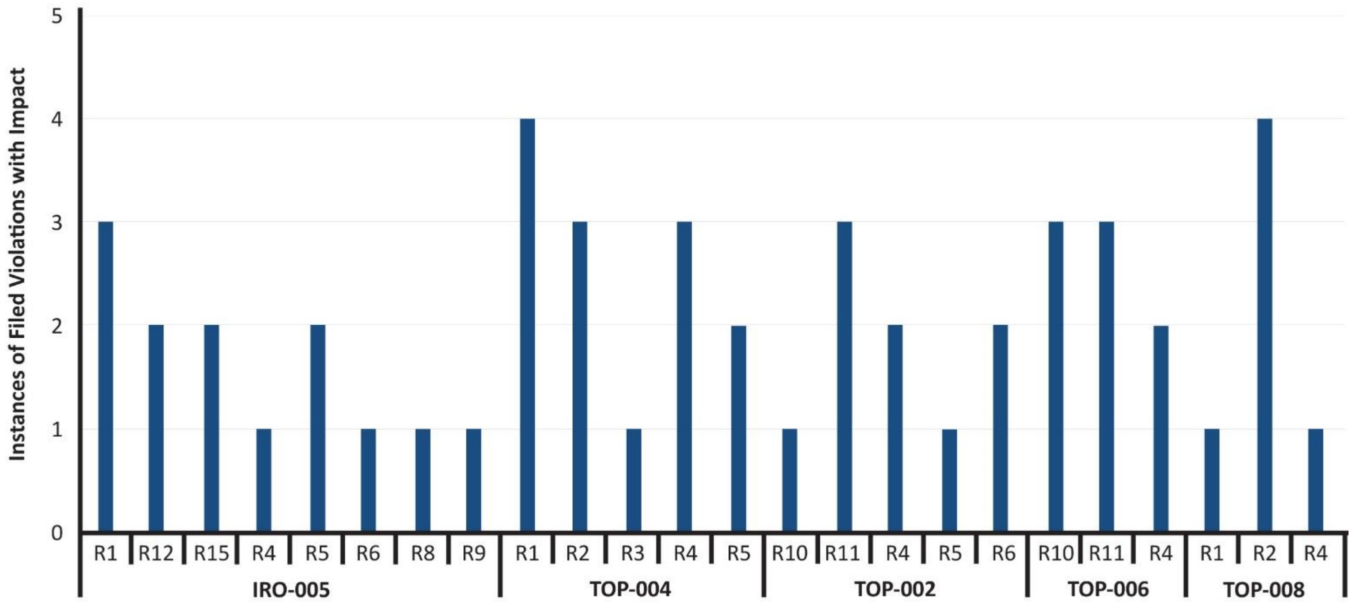

Figure 5.6: Most Frequently Filed Standards and Requirements (2014–2016 Data)

NERC provides quarterly updates on trends in the Compliance Monitoring and Enforcement Program[57] and will continue to update CP-1 and CP-2 during 2017. NERC also analyzed and reported on the causal trends associated with the violations depicted in CP-1 and CP-2 metrics. The additional analysis with conclusions and recommendations can be found on the NERC website.[58] At a high level, the key issues observed included the following:

- Monitoring and situational awareness
- Planning and system analysis
- Human performance

While the CP-1 and CP-2 metrics have only been included in two *State of Reliability* reports since their adoption, they provide beneficial information about which standards and requirements, when violated, have the potential for serious risk to the BPS and which ones have been observed to result in reliability impact. The analysis of these two metrics provide the registered entities with information to focus on improving processes, procedures, and controls in those areas where the most risk or impact has been determined to exist.

[57] http://www.nerc.com/pa/comp/CE/Pages/Compliance-Violation-Statistics.aspx

[58] http://www.nerc.com/pa/comp/CE/Compliance%20Violation%20Statistics/Analysis%20of%20Serious%20Risk%20Violations%20with%20an%20Impact.pdf

Chapter 6: Event Analysis

The industry's voluntary ERO EA Process provides information to the ERO and industry on the categories and causes of qualifying events. Review and analysis of this information can identify potential reliability risks or vulnerabilities to the BPS that need to be mitigated. Significant incidents have occurred that do not meet threshold criteria for inclusion in the EA Process; these are addressed in Chapter 2, Reliability Highlights.

Background

Since its initial implementation in October of 2010, the EA Process has collected 896 qualified events and yielded 125 lessons learned, including 13 published in 2016.[59]

The first step in the ERO EA Process is BPS awareness and the monitoring of the BPS for reliability incidents. BPS conditions provide recognizable signatures through automated tools, mandatory reports, voluntary information sharing, and third-party publicly available sources. The majority of these signatures represents conditions and occurrences that have little or no reliability impact. The ERO Enterprise monitors these signatures for significant occurrences and emerging risks and threats across North America.

Registered entities continue to share information and collaborate with the ERO well beyond any mandatory reporting in order to maintain and improve the overall reliability of the grid. Only a small subset of the reported occurrences rise to the level of a reportable event. **Table 6.1** provides details on the 2016 information, mandatory reports, and other information that is translated into products that address reportable events.

Table 6.1: Situational Awareness Inputs and Products for 2016

Information Received	Products
Mandatory reports	229 daily reports
339 DOE OE-417 Reports	28 special reports for significant occurrences
325 EOP-004-2 Reports	
2 EOP-002-3 Reports	1 reliability-related NERC Advisory (Level 1) Alert
Other information[60]	646 new Event Analysis entries (known as "Notifications" and associated with the 171 qualified events and the 267 nonqualified occurrences)
3,403 Intelligent Alarms Notifications	2 reliability-related NERC Recommendation (Level 2) Alert
4,238 FNet/Genscape Notifications and 946 Daily Summaries	
2,049 WECCnet Messages	
2,121 RCIS Messages	
2,393 Space Weather Predictive Center Alerts	
1,123 Assorted US Government Products	
5,260 Assorted Confidential, Proprietary, or Nonpublic Products	
2,235 Reliability Coordinator and ISO/RTO Notifications	

Analysis and Reporting of Events

Using automated tools, mandatory reports, voluntary information sharing and third-party publicly available sources, disturbances on the grid are categorized by the severity of their impact on the BPS. Table 6.2 contains a

[59] The link to the NERC Lessons Learned page: http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx
[60] Information sources listed in no particular order or priority, and not limited to these resources

consolidated chart of the reportable events since the program's inception (October 2010). Additional information on the EA Process can be found on the NERC website.[61] As of January 1, 2017, a new EA Process version will go into effect.[62]

Table 6.2: Events Analysis Event Summary			
Event Category	**Count (Total)**	**Count (2016)**	**Comments (2016 Events)**
CAT 1	712	163	71 - Three or more BPS facilities lost (1a) 5 - BPS SPS/RAS Misoperation (1c) 1 – Unintended loss 1,000-1,399MW generation in ERCOT (1g) 86 - Partial EMS (1h)
CAT 2	161	6	2 – Loss of Offsite Power (2d) 4 – Unintended loss of load (2f)
CAT 3	18	2	Loss of 1,400+ MW generation in ERCOT Loss of 2,000+ MW generation in other Interconnections
CAT 4	3	0	
CAT 5	2	0	
Total CAT 1-5 Events	**896**	**171**	
Nonqualified Occurrences Reported	**2,532**	**267**	

In 2016, there were 85 non Energy Management System (EMS) brief reports submitted to the ERO. This was a substantial increase when compared to 50 non-EMS reports submitted to the ERO in 2015. Of these 85 events, 77 were Category 1 events, six were Category 2 events, and two were Category 3.a events in ERCOT. Subsequent to January 1, 2017, the two Category 3.a events in ERCOT would have been classified as a Category 1.g events to more accurately reflect the risk associated with them.

Out of the 85 non-EMS events in 2016, there were 55 of these events (65 percent) that experienced one or more misoperations. In all 55 of these events, the misoperations exacerbated the severity of the event. Of these 55 events with misoperations involved, 27 events (49 percent) experienced a breaker failure scheme misoperation or bus differential misoperation. These types of misoperations typically have a high impact on the BPS, particularly when they clear a straight bus with multiple facilities. The 2016 percentage of events with misoperations compares closely to the 2013–2015 results.

[61] EAP process in effect through the end of 2016: http://www.nerc.com/pa/rrm/ea/EAProgramDocumentLibrary/ERO_EAP_V3_final.pdf
[62] EAP Process in effect as of January 1, 2017: http://www.nerc.com/pa/rrm/ea/ERO_EAP_Document/ERO_EAP_v3.1.pdf

There were 86 EMS events in 2016. Common themes for the EMS events were the following:

- Change management
- Testing procedures
- Vendor relationships
- Network infrastructure

Loss of situational awareness was identified as a moderate priority risk by the RISC. Loss of EMS events will continue to be a high priority for the ERO, as loss of situational awareness can be a precursor or contributor to a BES event.

The EMS Working Group (EMSWG) analyzes the events and data that are being collected about EMS outages and challenges. From the EA reports and the work of the Event Analysis Subcommittee (EAS), NERC published multiple lessons learned specifically about EMS outages and worked to build and support an industry-led EMS Task Force (EMSTF) to support the EAS. The hard work and active sharing of this group has reduced some of the residual risk associated with this potential loss of situation awareness and monitoring capability that comes with this type of event, and they will continue to provide valuable information to the industry. NERC hosted its fourth annual Monitoring and Situational Awareness Conference on September 27–28, 2016, with the theme of EMS Resiliency.

For trending of the number of events, NERC uses a standard Statistical Process Control methodology, resulting in control charts. The control chart provides control limits that are calculated by using an Individuals-Moving Range calculation. In this way, there is no unnecessary reaction to what would be considered normal variation in the numbers of events reported. This also helps determine what “normal” looks like when determining if any anomalies have occurred.

Figure 6.1 is the control chart for the 897 Qualified Events through 2016. In October 2013, when Version 2 of the EA Process introduced a new category of events, collectively known as Category 1h: Partial Loss of the EMS, occurrences that were not previously reported became visible and a shift in the control limits occurred. The control chart of events in 2016 shows the numbers of events were stable and predictable.

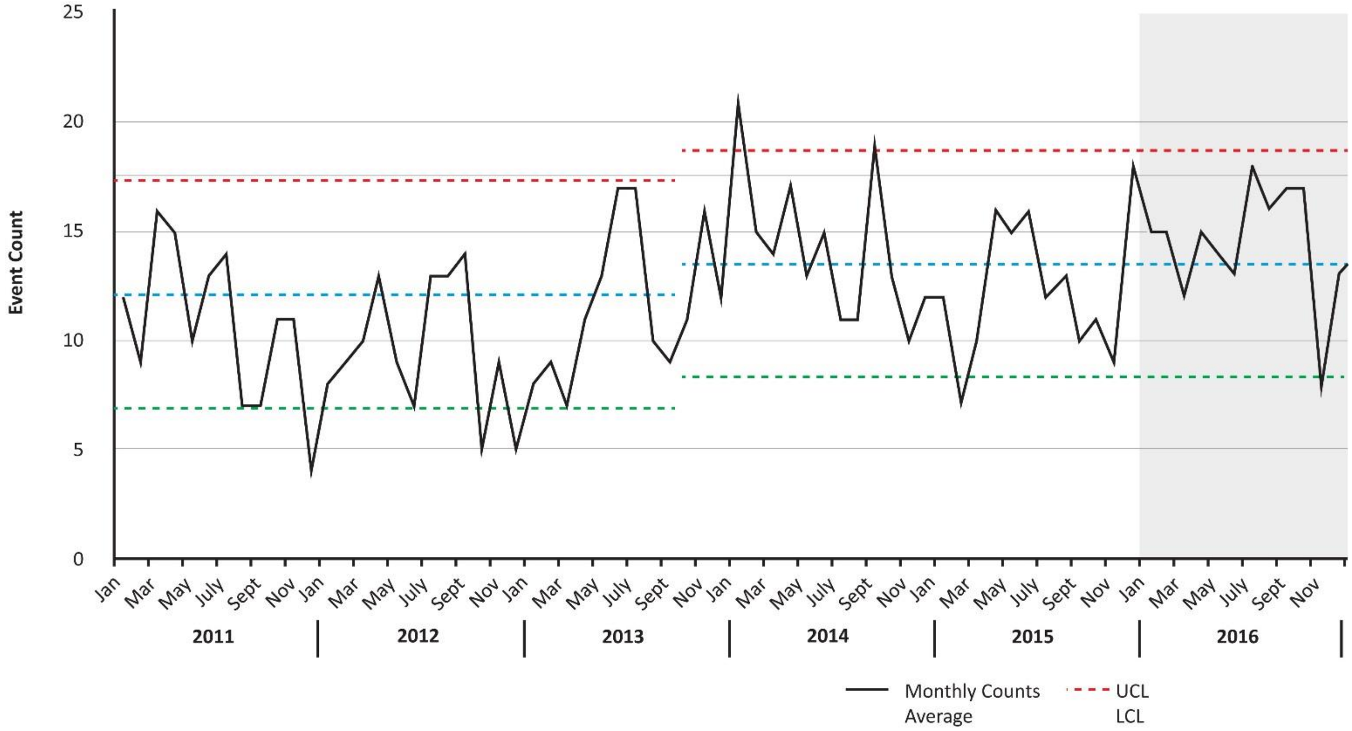

Figure 6.1: Control Chart for the Number Events (Per Month) Over Time

Through the EA Process, cause codes were assigned to 674 of the 896 events, leading to 2,279 root or contributing cause codes being identified. The root cause of every event cannot be determined, though many of the contributing causes or failed defenses can be established. **Figure 6.2** shows the overall breakdown of the identified cause codes of events.

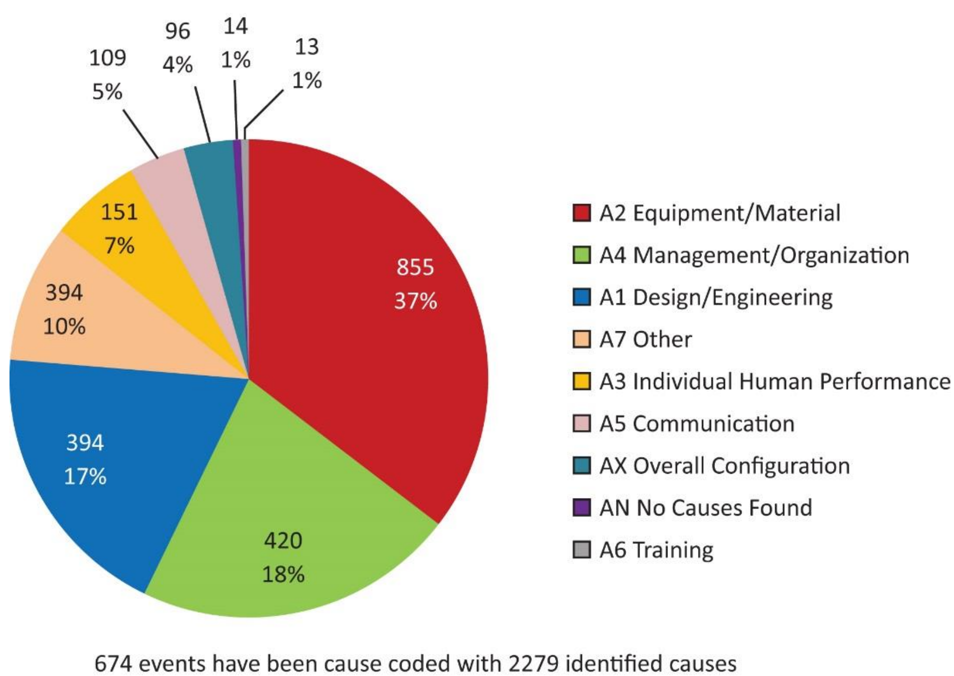

Figure 6.2: The Percentage of Contributing Causes by Major Category

Identification of these areas of concern allows for the prioritization and search for actionable threats to reliability. When this data was shared with the AC Substation Equipment Task Force (ACSETF) it was determined that, while the initial data pointed to the potential problem areas, the data was not detailed enough to analyze any specific problem areas. Following recommendations from the ACSETF report, an addendum was developed for the types of information needed to support the EA Process when failed equipment is identified.[63]

Out of the 85 transmission-related events in 2016, a total of 29 events (34 percent) experienced substation equipment failures. In total, 27 of these 29 substation equipment failures were either the initiating cause of the event or they subsequently increased the severity of the event. The substation equipment failures were as follows:

- 10 internal breaker failures
- 8 stuck/slow breakers
- 1 breaker bushing failure
- 2 shunt capacitor failures
- 2 lightning arrester failures
- 3 circuit Switcher/disconnect failures
- 1 free standing CT failure
- 1 potential transformer failure
- 1 bus insulator failure
- 1 SF6 bus leak/failure
- 1 battery/charger failure

The top two causes of substation equipment failures were related to circuit breakers. As noted in their report of March 2015, the ACSETF[64] concluded that 1) circuit breaker failures have the highest percentage of failures; 2) the top four subcomponents are interrupter, mechanism, trip coil, and bushing; and 3) inherent in circuit breaker failure is an increased probability that additional BPS elements will also be forced out of service. NERC EA has created a template to collect additional information for substation equipment failures and will continue to analyze the data for common themes. NERC also published a lessons learned in March 2017, “Slow Circuit Breaker Operation Due to Lubrication Issues.”

Asset management and maintenance was identified as a low-priority risk by the RISC.[65] Low-priority risks do not mean that possible reliability impact is small, but rather the profiles are understood with clearly identifiable steps that can be taken to manage risk. The failure to properly commission, operate, maintain, and upgrade BES assets could result in more frequent or more severe outages as equipment failures initiate or exacerbate events.

A similar identification of trends can be observed in the large contribution of “less than adequate” or “needs improvement” cause factors in management and organizational practices that contribute to events. Many of these threats can be identified and shared with the industry for awareness. For example, in **Figure 6.3**, the identification of some of the challenges to organization and management effectiveness are identified.

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63 http://www.nerc.com/pa/rrm/ea/Pages/EA-Program.aspx

64 http://www.nerc.com/comm/PC/AC%20Substation%20Equipment%20Task%20Force%20ACSETF/Final_ACSETF_Report.pdf

65 http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

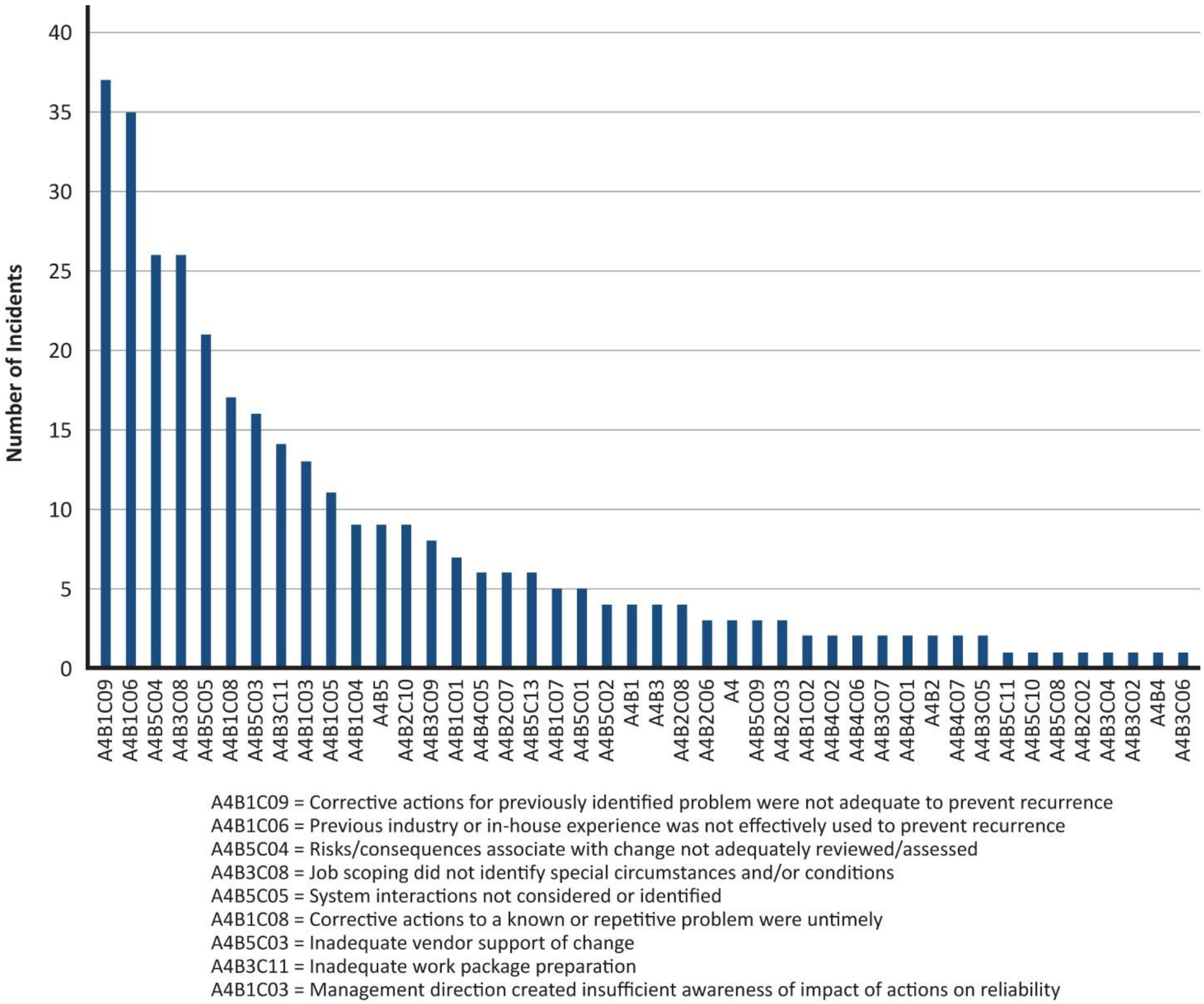

Figure 6.3: Management or Organization Challenges Contributing to an Event

Major Initiatives in Event Analysis

Human Performance

EA has identified work force capability and human performance (HP) challenges as possible threats to reliability. HP and a skilled workforce was also identified as a priority by the RISC. Workforce capability and HP is a broad topic but can be divided into management, team, and individual levels. NERC held its fifth annual HP conference in Atlanta, Improving Human Performance on the Grid, at the end of March 2016.[66] Its sixth annual HP conference, Improving Human Performance and Increasing Reliability on the Bulk Power System, was held jointly with NATF in Atlanta in March 2017.

NERC continues to conduct cause analysis training with staff from the Regions and registered entities. As of December 2016, personnel from all eight Regions, and approximately 1,380 people from 250 different registered entities have received cause analysis training, roughly 11,000 hours of training.

[66] http://www.nerc.com/pa/rrm/hp/2016_Human_Performance_Conference/Forms/AllItems.aspx

NERC held its fourth annual Monitoring & Situational Awareness Conference at the California ISO offices in September 2016. This conference continues to focus on issues related to EMS events, situational awareness, and EMS resiliency.

2016 Winter Weather Review

On September 1, 2016, a webinar and preparedness training was provided to the industry to prepare for Winter 2016–2017. The objective of the "Winter Preparation for Severe Cold Weather" webinar was to remind industry of the need to continue to appropriately prepare for the upcoming winter weather forecasts. The webinar was well attended by industry with over 200 users, owners, and operators of the BPS participating in the webinar. The webinar provided an overview of current reference materials and updated training packages. Information was shared from the *Short-Term Special Assessment, Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*[67] and the preliminary 2016–2017 North America Winter Outlook. The winter preparation materials can be found on NERC's website.[68]

Event Severity Risk Index

NERC EA staff calculates an event severity risk index (eSRI) for all qualified events (as defined in the EA Process). This calculation is based on the methodology used by NERC for the standard SRI as described in Chapter 3, and it considers the loss of transmission, the loss of generation, and the loss of firm load (along with load-loss duration).

The formula used is:

$$eSRI = RPL * W_L * (MW_L) + W_T * (N_T) + W_G * (N_G)\text{, where}$$

RPL = Load Restoration Promptness Level

W_L = Weighting of load loss (60 percent)

MW_L = normalized weighting of load loss

W_T = weighting of transmission lines lost (30 percent)

N_T = normalized number of ac transmission lines lost, in percent

W_G = weighting of loss generation (10 percent)

N_G = normalized Net Dependable Capacity of generation lost

The value of this calculation results in a number between zero and one; thus, for easier use in analysis, this small number is multiplied by 1000.

Every event reported through the EA Process has its eSRI calculated, but for the purposes of trending, certain event groups are excluded. The excluded groups are the following:

- Weather-driven events: The purpose of excluding the weather-driven events is because they are outside of the control of the BES entities, thus not considered when studying impact over which there is control. A weather-driven event is an event whose root cause is determined to be weather (or other force of nature); examples would include the Hurricane Sandy event, an earthquake, or a string of tornadoes knocking down transmission towers, among others. There have been 14 of these events since October 2010.

[67] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf
[68] http://www.nerc.com/pa/rrm/ea/Pages/Cold-Weather-Training-Materials.aspx

- AESO islanding events: As AESO designed islanding events as an intentional act in their SPS schemes, these are also excluded.
- Category 4 and 5 events: The purpose of excluding Category 4 and 5 events is that they are monitored and tracked in a distinct manner, so counting them in this trending would be duplicative.
- Events prior to 2011: For the purposes of trending, it has been decided that the 18 events in 2010 would not be included as this was such a small sample from a limited time frame.

Total Qualified events reported is 897.

- Excluded 2010 events: 20 which leaves 877 events.
- Excluded Category 4 and 5 events: five, which leaves 872 events.
- Excluded Weather-driven events (root cause is weather): 10, which leaves 862 events.
- Excluded AESO Islanding: 35, which leaves 827 events.

Number of events used for eSRI trending: is 827 events.

Once this number is calculated for each event and is plotted in chronological sequence, the slope of the trend line is calculated and plotted. In this way, the trend can be visually identified (as well as numerically calculated using statistical software). Every day has its eSRI calculated (meaning a day with no events has an eSRI = 0.000). For any days with multiple events, the eSRIs are additive.

The eSRI calculations are shown in **Figure 6.4** and **Figure 6.5**.

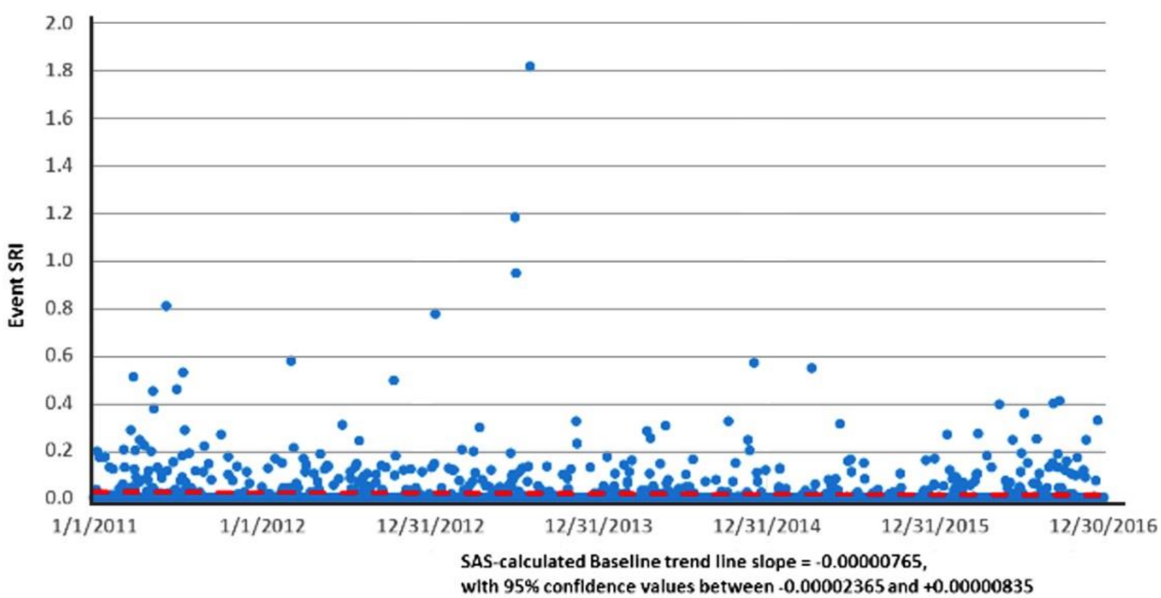

Figure 6.4: Trend line of eSRI

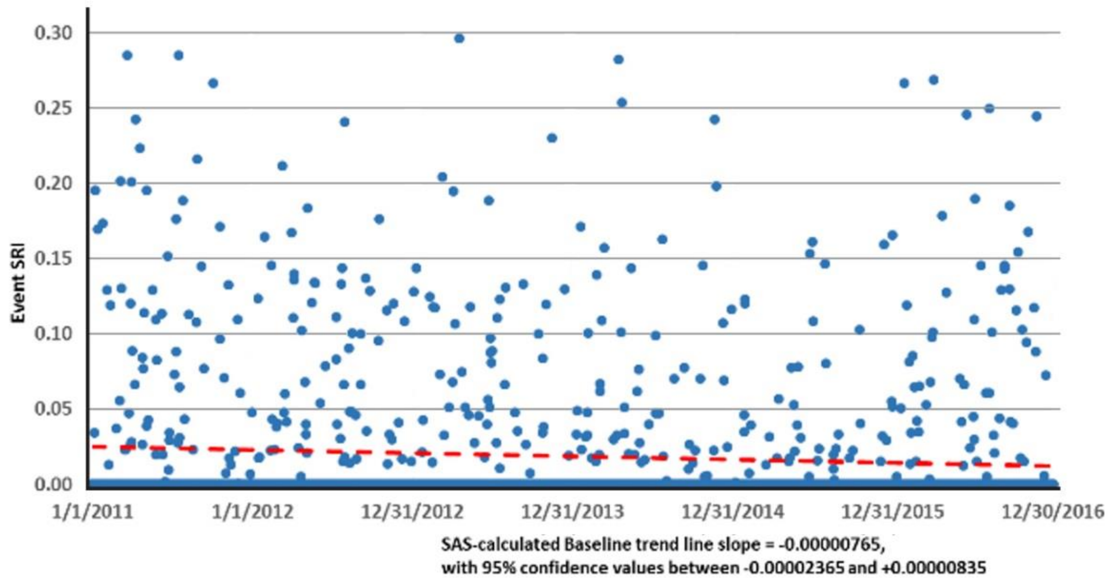

Figure 6.5: Expanded View of eSRI Trend Line Y axis 0 to 0.3

As can be seen from the expanded view (included to address the scale limit visibility), the eSRI is approximately zero within the statistical confidence interval. Furthermore, as indicated in **Figures 6.4** and **Figure 6.5**, the trend line is relatively flat.

Summary

The EA Process continues to provide valuable information for the industry to address potential threats or vulnerabilities to the reliability of the BPS. The ability to identify specific pieces of equipment that are potential threats, as well as emerging trends that increase risk to the system, illustrates the value of the EA Process. These outcomes, coupled with the ability to actively share the information through lessons learned, webinars, technical conferences, and related venues, remain critical to the sustainment of high reliability.

Chapter 7: BES Security Metrics

Background

One of the most complex endeavors that NERC undertakes is assessing security risks to the BPS. Capturing metrics on physical and cyber security is equally complex. A great deal of data is available regarding cyber incidents, but not all incidents may cause loss of load or impact grid operations. Specifically, the data NERC received in 2016 from OE-417s and EOP-004s show low numbers of cyber penetrations of grid operating systems in North America and few reports of physical intrusions.[69] These low numbers indicate that NERC's efforts with industry have been successful in isolating and protecting operational systems from various adversaries. The numbers are also an indication that the electricity industry's record of breaches is much lower than many other sector (including government agencies) that have been victims of numerous data breaches.[70]

The number of reportable cyber security incidents affecting customers resulting in loss of load remains at zero, and the number of reportable cyber incidents affecting grid operations was also at zero for the last two years. During 2015 and 2016, no physical security events occurred that caused a loss of load.[71]

NERC takes all cyber incidents seriously. Although significant risks to the grid still exist, the low numbers show that the electricity industry has seen exceptional performance in protecting the grid from security incidents to date.

Measuring Security Risks

Internet-facing corporate systems at utilities are probed hundreds of thousands of times per day. Once in a while, a laptop might become infected. These incidents may occur a few times a month for a typical company and up to several dozen times per month for the larger utilities. No clear line exists on what to report on these routine cyber issues, near-misses, or possible attempts that are difficult to measure and do not cause loss of load or impact grid operations.

On the control systems side, the number of incidents reported affecting grid operations was zero throughout 2015 and 2016. NERC currently has superior reporting and ethics on disclosure in place, and companies are seeing and fixing issues within their own information technology (IT) departments. However, NERC cannot solely rely on an incident reporting metric as a sign of risk; this kind of reporting would be misleading as a result of the difference between the numbers of incidents reported on the corporate versus control systems side.

Another way to measure cyber risk that does not depend on self-reporting is to use the analytic data gathered from the CRISP and the CAISS to calculate risk indices based on the number of cyber incidents discovered. This measurement would be more reliable than self-reporting incidents but could somewhat overstate BPS concerns because the collected data is only from the corporate interfaces to the internet and not from control systems at this point, assuming that the two systems are air gapped.

NERC, in collaboration with the DOE and the National Laboratories, is exploring ways operational traffic could also be captured, in addition to the large data sets of information flowing from the corporate or business systems. Once CAISS—which is currently a pilot program—becomes more widespread, it will allow indicators of compromise (IOC) that may be seen on enterprise IT systems via CRISP to be compared to any potential intrusions or malicious data collected from control systems, further refining risk metrics to grid operations.

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[69] See Appendix G for the BESSMWG metrics.

[70] http://www.nydailynews.com/news/national/hacker-dumps-info-thousands-homeland-security-workers-article-1.2524440; https://www.scmagazine.com/anonsec-claims-credit-for-nasa-drone-hack/article/528448/; http://www.cbsnews.com/news/irs-identity-theft-online-hackers-social-security-number-get-transcript/

[71] In late 2014, a physical security event occurred that resulted in loss of load; however, this event was not officially reported until January 2015. See *(enter corresponding EO-417 for citation)*.

And finally, the most important cyber risk faced on the grid is more existential: the capability of nation-states or other capable adversaries to launch a massive cyberattack to disrupt electricity operations. The chances of this happening are extremely low; however, the consequences could be significant for this worst case scenario. Currently, no method exists to determine a true quantitative measure of this sort of risk. What NERC can measure is that no major cyber- and few physical-related load losses have happened to date; that extremely low numbers of incidents have occurred on the operating side, and that attention to security performance has been excellent on the corporate side.

The BESSMWG, under the direction of the Critical Information Protection Committee (CIPC), chose to measure the existential risk by adopting Metric 6, based on the NIST Global Cyber Security Vulnerabilities Index and Metric 7 as PWC's Global State of Information Security index.[72] Both of these reports chart cyber risk year-over-year on a global basis across all sectors from credible sources. With a global outlook towards cyber and physical attacks on grid infrastructure, these reports recognize that other utilities around the world have been successfully attacked by capable adversaries with some attacks resulting in loss of control and shutdown of operational electric loads.

Cyber Security Incident Case Study: Ukraine

In December 2015, Ukraine fell victim to a cyber attack that included spear phishing, credential harvesting and lateral movement, unauthorized remote access, telephony denial-of-service, and sustaining persistent access. In February 2016, NERC's E-ISAC provided subject matter expertise to develop the NERC alert, *Mitigating Adversarial Manipulation of Industrial Control Systems as Evidenced by Recent International Events*, which shared techniques observed in the Ukraine cyber attacks. Most of these same tactics and techniques were used in a subsequent series of attacks against Ukraine in December 2016, when Ukraine's state-owned national power company, Ukrenergo, experienced an outage at an electrical substation in the capital city of Kyiv. Service was restored as a result of manual operator intervention. Researchers confirmed that the outage was the result of a cyber attack that occurred during the end of a protracted campaign.

In addition to the 2016 NERC alert, the E-ISAC worked with the SANS Institute to publish a Ukraine Defense Use Case (DUC).[73] This 29-page report "summarizes important learning points and presents several mitigation ideas based on publicly available information on Industrial Control Systems (ICS) incidents in Ukraine."

The techniques used against Ukraine have several options for remediation and prevention. NERC, through standards and compliance; and the E-ISAC, through information sharing, industry collaboration, and publications like the NERC alert and DUC; often stresses and shares these remediation and prevention tips with the electricity industry.

The events in Ukraine underscore the importance of grid security and provide a real-world example of consequences of a cyber attack on the electrical grid. The events abroad also highlight the importance of user training and information sharing in order to prevent a similar attack on the North American power grid. Similar tactics are woven into the North America-wide grid security exercise (GridEx) series.

Beyond Standards and Compliance: The E-ISAC

The E-ISAC's mission is to be a leading and trusted source that analyzes and shares electricity industry security information. The E-ISAC gathers security information, coordinates incident management, and communicates mitigation strategies with stakeholders within the electricity industry across interdependent sectors and with government partners.

[72] PWC did not provide the data for 2016; the BESSMWG is working to determine if this information will be available in future. If not, the BESSMWG will seek alternate sources for similar data.
[73] https://ics.sans.org/media/E-ISAC_SANS_Ukraine_DUC_5.pdf

Most of the E-ISAC's communications with electricity industry members are via an internet portal that was significantly upgraded at the end of 2015. In 2016, the E-ISAC added 1,512 new users to the portal, a growth of 19.5 percent over 2015. The most popular views by members were documents, including weekly reports and analytical assessments posted by the E-ISAC. In 2016, 1,525 unique users downloaded 713 different documents 18,555 times. The top downloaded document of 2016 was the E-ISAC/SANS Ukraine Defense Use Case previously mentioned.[74] As the E-ISAC continues to collect portal activity data, the information will assist the E-ISAC in recruiting new members to the portal and determining how the E-ISAC can best serve members' interests and needs.

Increased physical security and cyber security information sharing will enable the E-ISAC to conduct more complete analysis. Robust data collection over time helps identify important trends and patterns. By providing unique insight and analysis on physical and cyber security risks, the E-ISAC's aim is to add value for its members and assist with overall risk reduction across the ERO Enterprise.

Cyber Security Risk

In 2016, there were 241 cyber bulletins posted to the E-ISAC portal.[75] Of the 241 cyber bulletins, 210 were posted based on information provided by members or posted by members themselves. This trend is consistent with the 218 cyber bulletins in 2015. The E-ISAC expects this number to increase in 2017 as member participation increases. The E-ISAC also posted several bulletins based on information obtained from government partners and trusted open source partners. Like 2015, the second quarter (Q2) of 2016 saw the most portal posts based on information provided by members.

Just under half of the reports from members involved phishing incidents. Other important trends and analysis conducted throughout the year focused on the Dridex campaign, ransomware, and the Internet of Things (IoT). The E-ISAC also monitored several important cyber events in 2016, including malicious cyber activities by the Russians and a power outage in Ukraine.

Several key topics and takeaways from the analysis of reports include the following:

Phishing: In 2016, over 40 percent of cyber bulletins posted were about phishing; this trend is consistent with what the E-ISAC observed in 2015. These phishing emails contained information relating to the Dridex campaign, html credential harvesting, Gh0st RAT, Locky, typosquatting, whaling, and vawtrak attempts.

Ransomware: Since the beginning of 2016, the E-ISAC reporting and media coverage pointed to a significant increase in ransomware-specific cyber extortion activity. Ransomware is a special class of disruptive, malicious software designed to deny access to data and files until the victim meets payment demands. Once compromised, the victim may have to restore systems from back-up tapes or pay the ransom with the hope of regaining access to the data and files. In response to the prevalence of ransomware across all critical sectors and its destructive capabilities, the E-ISAC provided subject matter expertise in a NERC alert that was issued in June 2016[76]. The E-ISAC also released a detailed assessment in May 2016 outlining the evolution of ransomware tactics.[77]

Internet of Things (IoT): Serious concerns surround the security of devices designed to be used as part of the IoT. Cyber security practitioners generally agree that most IoT devices connected to the Internet are likely to be a target because they generally do not have security as an important part of their design process. Due to the highly

[74] https://www.eisac.com/Collaboration#/document/4185

[75] Bulletins describe physical and cyber security incidents and provide timely, relevant, and actionable information of broad interest to the electricity industry.

[76] http://www.nerc.com/pa/rrm/bpsa/Facility%20Ratings%20Alert%20DL/NERC_Alert_A-2016-06-07-01_Ransomware_Extortion_Poses_Increasing_Risk.pdf

[77] This document is not publicly available.

interconnected and unauthenticated state of the IoT, the lack of sufficient security design in IoT products and toys can be leveraged against critical systems accessible from the internet.

The use of a large number of IoT devices can be harnessed from all areas of the Internet rather than a small number of networks. This massive scale of the IoT devices has successfully generated attack throughput rates on the order of several hundred megabits-per-second to one terabit-per-second (tbps) or more.

The October 21, 2016, distributed denial-of-service (DDoS) attack against the Dyn-managed domain name system (DNS) infrastructure resulted in 1.2 tbps of network throughput (also referred to as bandwidth) being used against the DNS address provider's infrastructure. Malware, such as Mirai, will continue to grow as the overall throughput of internet providers' infrastructure will be the ultimate limiting factor.

A level 2 NERC alert, published on October 11, 2016, was concerned with issues with IoT devices that are connected to the public Internet. In conjunction with the alert, on October 24, 2016, the E-ISAC released its *Internet of Things DDoS White Paper*.[78]

GRIZZLY STEPPE: On December 29, 2016, The Department of Homeland Security (DHS) and the FBI released a Joint Analysis Report (JAR) titled, "GRIZZLY STEPPE - Russian Malicious Cyber Activity[79]," that provided details of the tools used by Russian intelligence services to compromise and exploit networks and endpoints associated with a range of U.S. government, political, and private sector entities. The JAR also included recommended mitigations and information on how to report such incidents to the U.S. government. The E-ISAC analyzed the indicators of compromise (IOC) provided by government intelligence for potential malicious network traffic that may affect the electricity industry.

Burlington Electric Department (utility) received this information from DHS and found a potentially compromised laptop. The utility conducted further analysis and investigation determining the laptop had not been connected to the grid and that the incident was not linked to any effort by the Russian government to target or hack the utility. Based on information currently available, the E-ISAC believes that neither the electricity industry nor this particular utility were targeted by this cyber attack. The information points to this activity as part of a broader, untargeted campaign searching for vulnerable computers to exploit. Both the wide range in age of indicators in question and the fact that addresses belonged to content providers, cloud computing providers, and internet service providers, in addition to private companies and individuals made the connection of any activity difficult to substantiate as belonging to a particular actor.

CRISP

CRISP is a public-private partnership, cofounded by the DOE and NERC, and managed by the E-ISAC, that facilitates the exchange of detailed cyber security information among industry (i.e., E-ISAC, DOE, and Pacific Northwest National Laboratory). This partnership facilitates information sharing and enables owners and operators to better protect their networks from sophisticated cyber threats.

Participation in the program is voluntary and enables owners and operators to better protect their networks from sophisticated cyber threats. The purpose of CRISP is to collaborate with industry partners to facilitate the timely bidirectional sharing of unclassified and classified threat information. CRISP information helps support development of situational awareness tools to enhance the industry's ability to identify, prioritize, and coordinate the protection of its critical infrastructure and key resources.

[78] This document is not publicly available.
[79] https://www.us-cert.gov/sites/default/files/publications/JAR_16-20296A_GRIZZLY%20STEPPE-2016-1229.pdf

CRISP participant companies serve approximately 75 percent of electricity consumers in the United States. The quantity, quality, and timeliness of the CRISP information exchange allows the industry to better protect and defend itself against cyber threats and to make the BPS more resilient.

E-ISAC Member Engagement

In 2016, the E-ISAC completed its first full year working with the Member Executive Committee (MEC), a subcommittee of the Electricity Subsector Coordinating Council (ESCC) that consists of three chief executive officers and eight chief information officers or chief security officers. This group provides strategic guidance to improve and enhance the E-ISAC, particularly in the areas of the products and services the E-ISAC offers to its members. The MEC has two working groups: the Member Engagement, Products, and Services (MEPS) Working Group and the Operations, Tools, and Technologies (OTT) Working Group.

While enhancing the E-ISAC's products and services will be an ongoing activity, the E-ISAC, MEPS, and the OTT made great progress in 2016 to address and implement the MEC recommendations and work plan items. These products and services and continued member engagement will enhance information sharing and as a result the overall security of the grid.

E-ISAC Threat Workshop

As a result of planning and discussions with representatives from the MEPS, the E-ISAC has started hosting unclassified threat workshops biannually. These threat workshops bring together security experts from government and industry to discuss threats facing the electricity industry. The discussions include a focus on past threats, incidents and lessons learned, current threats that may impact industry, or views on emerging threats. The E-ISAC held its first threat workshop on December 6, 2016, in Washington, DC; the second workshop is scheduled for June 20, 2017, in Irwindale, CA.

To maximize information sharing with asset owners and operators (AOO), the workshops include discussions between presenters and attendees during each briefing with E-ISAC analysis of the topics raised and dedicate time to industry discussion after the briefings. These discussions and added analysis by the E-ISAC better enable AOOs to mitigate threats and incorporate best practices.

E-ISAC Monthly Briefing Series Update

The E-ISAC continues to host its monthly briefing series for AOOs, covering timely, CIP topics for participants. The briefings involved federal and technical partners, including DHS staff from the Industrial Control Systems Cyber Emergency Response Team (ICS-CERT), the Office of Intelligence and Analysis, and the National Cybersecurity and Communications Integration Center (NCCIC), as well as FireEye and iSIGHT Partners. The monthly briefing series also includes special guest presentations.

Participation in the monthly briefings during 2016 ranged from 180 to over 400 attendees. This was the first full year that the series included a physical security section (added April 2015), and full replays were available for member download (added December 2015). Based on polling feedback, 70 to 96 percent of attendees consider the meetings to be of "Considerable Value" or "Great Value." The E-ISAC will continue to encourage industry to share security best practices and lessons learned on topics relevant to the industry by inviting more industry AOOs as guest presenters.

Grid Security Exercise (GridEx)

NERC conducted its third biennial grid security and emergency response exercise, GridEx III, on November 18–19, 2015. NERC's mission is to assure the reliability of the BPS, and GridEx III provided an opportunity for industry and other stakeholders to respond to simulated cyber and physical attacks affecting the reliable operation of the grid. Led by the E-ISAC, GridEx III was the largest geographically distributed grid security exercise to date. GridEx III consisted of a two-day distributed play exercise and a separate executive tabletop on the second day. More than

4,400 individuals from 364 organizations across North America participated in GridEx III, including industry, law enforcement, and government agencies.

In March 2016, the E-ISAC released three reports (one available to the public and two restricted to industry and government stakeholders) regarding the lessons learned on GridEx III. The reports summarize the exercise and provide recommendations that the E-ISAC has integrated into its internal crisis action plan and standard operating procedures.[80] In addition, the ESCC has adopted many of the recommendations into its playbook and used the GridEx III exercise to spur action on cyber mutual assistance, increase spares of critical equipment, and provide cross-sector support during crisis situations. Finally, all participating organizations were able to improve internal and external communications and relationships with important stakeholders and exercise crisis response procedures against an advanced attack scenario that identified potential gaps and improvements to improve security, resilience, and reliability.

Grid Security Conference (GridSecCon)

The E-ISAC hosted over 400 electricity cyber and physical security professionals in Quebec City, Canada, October 17–23, 2016. GridSecCon 2016 provided free training on physical and cyber security issues and technologies, such as Ukraine, Grassmarlin, and Cyber Attack Defense Training Exercise for the Grid. The conference included speaker sessions discussing industry's work with government partners, space weather, hunting and killing on networks, and advanced research and development in the industry.

Cross-sector Activities

The E-ISAC engages with the government at all levels, including international, federal, state, local, territorial, tribal, and provincial governments. It is also includes close international allies with critical infrastructure protection sector partners and other ISACs.

During 2016, the E-ISAC's federal partners were active in response to Presidential Policy Directive 41: *United States Cyber Incident Coordination* and created projects covering cyber mutual assistance, high profile exercises, cyber incident response plans, learning opportunities for the E-ISAC staff, and power outage incident technical reference products.[81] The E-ISAC worked closely with our federal partners in support of their activities and provided feedback where appropriate, such as with the recently updated National Cyber Incident Response Plan (NCIRP)[82]. The E-ISAC has also maintained participation with the NCCIC, the National Integration Center, and the National Operations Center.

Through the National Council of ISACs (NCI), the E-ISAC is able to collaborate with all critical infrastructure-specific ISACs. The E-ISAC assisted the NCI in establishing new information sharing procedures and collaborative analytical approaches. This partnership helped lead to additional threat briefing opportunities and increased information sharing. Furthermore, this partnership allowed the E-ISAC to provide additional insight and analysis on key topics, such as the Ukraine events and the IoT emerging issue.

Outlook for 2017 and Recommendations

NERC and the electricity industry have taken actions to address cyber and physical security risks to the reliable operation of the BPS as a result of potential and real threats, vulnerabilities, and events. NERC and the BESSMWG, under the direction of CIPC, will continue to do this in 2017 with the development of metrics that provide a global and industry-level view of how security risks are evolving and indicate the extent to which the electricity industry is successfully managing these risks.

[80] http://www.nerc.com/pa/CI/CIPOutreach/GridEX/NERC%20GridEx%20III%20Report.pdf.

[81] https://obamawhitehouse.archives.gov/the-press-office/2016/07/26/presidential-policy-directive-united-states-cyber-incident.

[82] https://www.us-cert.gov/ncirp

The following recommendations will guide NERC and the BESSMWG in maturing existing and developing new metrics to enhance industry's view of evolving security risks:

- Redefine reportable incidents to be more granular, and include zero consequence incidents that might be precursors to something more serious.
- Use CRISP data to run malware signature comparisons to see how many hits occur on a benchmark set of entities and if any have serious implications for the grid. This metric could be used to provide a percent change from a benchmark year-over-year.
- Use data obtained from CAISS and similar capabilities to characterize the type and frequency of various cyber threats reported through the year.
- Include other data sources such as the FBI, SANS Institute, Verizon, etc., as input for understanding the broader security landscape surrounding critical infrastructures.

Chapter 8: Actions to Address Recommendations in Prior State of Reliability Reports

The *State of Reliability Report* identifies key findings, and many of these findings contain recommended actions for NERC or the larger ERO Enterprise, PAS, and other subcommittees and working groups. **Table 8.1** shows the number of past recommendations and includes whether the item was completed as of the *2016 State of Reliability Report*; was ongoing in 2016, but has since been closed out as a completed recommendation; or is still an ongoing recommendation. Actions completed through the 2016 report are considered archived, and details about their completion are available in this chapter of the report.[83]

Table 8.1: Recommendation Status Summary

Key Finding Action Status	2011	2012	2013	2014	2015	2016	Total
Completed Status Through 2016 Report	4	6	6	5	8	0	29
Completed During 2016	0	0	1	0	1	3	5
Ongoing as of 2017 Report	0	0	0	0	3	4	7
Total Actions from All Reports	**4**	**6**	**7**	**5**	**12**	**7**	**41**

Table 8.1 shows that, over the six years of reports, 41 recommendations have been considered actionable. Actions to address those specific items have been completed for 34 recommendations. These actions are understood to have improved the reliability of the BPS. In this report, additional key findings and recommendations are identified and will be reported in future *State of Reliability Reports*.

Table 8.2 outlines actions that have addressed the recommendations completed during 2016, and **Table 8.3** outlines recommendations where actions are currently ongoing and will be included in future reports.

[83] Prior *State of Reliability* reports can be found at the following locations:
http://www.nerc.com/comm/PC/Performance Analysis Subcommittee PAS DL/2011_RARPR_FINAL.pdf.
http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/2012_SOR.pdf.
http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/2013_SOR_May 15.pdf.
http://www.nerc.com/pa/RAPA/PA/Performance Analysis DL/2014_SOR_Final.pdf.
http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf

Completed Recommendations

Table 8.2: Completed Recommendations				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
1	2013	Page 17 Paragraph 1	A small subject matter expert technical group should be formed to further study the data collection assumptions when assigning the “Unknown” cause code.	The TADSWG analyzed outages with the “Unknown” cause code; they focused on sustained outages greater than ten minutes. NERC provided blind (nonattributable) results of statistical analyses of entities submitting the highest numbers of outages with Unknown cause code normalized alternatively by number of circuits and by 100 circuit miles. A further list grouped statistically similar entities for submission of Unknowns (from the group with the most to the group with the least submissions of outages with an Unknown cause code). The lists were made available to representatives of the Regions to assist in their discussions with member Transmission Owners (TOs). No Owner can view other Owners’ rankings, but each Owner can view its own ranking and in which statistical group it resides. REs have worked with TOs to improve data that was collected and to reduce unknown sustained outage causes. This effort serves as a model for subsequent investigative analysis. Additional detailed analysis of these cause-coded outages that are consistent with analysis performed by other transmission analytical groups, like the NATF, are being reviewed and will further inform the process. Industry awareness of these cause codes is being elevated by TADSWG and REs. *The State of Reliability 2017* details a reduction in outages with the cause code of Unknown in calendar year 2016. Efforts will continue, but the recommendation is now complete.

Table 8.2: Completed Recommendations				
Item Reference	Finding SOR Report Year	Key Finding SOR Reference	Recommendations	Actions Taken to Date
2	2015	Page 9 Paragraph 5	NERC, working with the NATF, should evaluate the failure rate of circuit breakers and determine the impact of bus configuration on ac transmission circuit outages. NERC, working with IEEE and other applicable industry forums, should develop a consistent method for the collection and distribution of ac substation equipment failure data.	NERC and NATF analyses have confirmed that circuit breaker failure remains the highest probability failure within the Substation Equipment Failure cause code. NERC's analysis has confirmed that the failure of a circuit breaker to operate properly increases the probability that additional BPS elements will also be forced out of service, increasing the TOS of the event. Bus configuration has the single largest impact on this severity increase. From greatest to least increase, the top three bus configurations are: 1) straight bus, also known as main and transfer bus, 2) ring bus, and 3) breaker and a half bus. Three actions are ongoing based on the completed recommendation: • TADSWG is pursuing a multi-pronged approach to obtain more granular data for the AC Substation Equipment Failure cause code. TADSWG is first working with NATF seeking blind data analysis regarding sub-cause codes to determine what insights this might provide. • NERC's EA group is continuing its analysis of voluntary and mandatory event submissions through the EA Process in order to issue lessons learned but using much more detailed failure cause codes for substation equipment. • The EA group is also participating in and utilizing statistical and trending failure data from outside sources such as the Electric Power Research Institute (EPRI) and the Centre for Energy Advancement through Technical Innovation (CEATI). Collaboration and coordination with these outside organizations are expected to assist in benchmarking

Table 8.2: Completed Recommendations				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
				and validating equipment failure trends, including further development of possible corrective actions.
3	2016	Page 1 Key finding 1	Results indicate that targeting the top three causes of misoperations should remain an effective mitigation strategy. NERC should, in collaboration with industry, improve knowledge of risk scenarios by focusing education on the instantaneous ground overcurrent protection function and on improving relay system commissioning tests.	The ERO Enterprise, in collaboration with industry and IEEE, is developing and delivering education focused on the instantaneous ground overcurrent function and commissioning tests. For example, RF conducted its *Protection System Workshop for Field Personnel* on August 16–17, 2016. It focused on commissioning tests. Texas RE working with ERCOT's System Protection Working Group developed, "A Review of Ground Fault Protection Methods for Transmission Lines[84]" a white paper aimed at reducing protection system misoperations and focused on the instantaneous ground overcurrent function. This document published in Spring 2017. NERC and the SPCS are collaborating with the IEEE Protection System Relaying Committee and an I25 drafting team to release an IEEE Guideline for commissioning testing for use by the industry. The details and results of each of these efforts are being shared across the ERO Enterprise and with each Region's members to improve protection operational performance. These actions all focus on the two areas addressed in the recommendation, and while NERC always strives for continuous

84 http://www.ercot.com/content/wcm/key_documents_lists/27278/ERCOT_SPWG_Review_of_Ground_Fault_Protection_Methods_For_Transmission_Lines.pdf

Table 8.2: Completed Recommendations				
Item Reference	Finding SOR Report Year	Key Finding SOR Reference	Recommendations	Actions Taken to Date
				improvement, this recommendation is now complete.
4	2016	Page 2 Key Finding 4	Through the efforts of the EAS and participation of registered entities, NERC should continue to develop and publish lessons learned from qualifying system events.	Part of the EA Process is to publish lessons learned from system events. EAS will continue to develop and publish lessons learned for the registered entities.
5	2016	Page 4 Key Finding 7	NERC should actively maintain, create, and support collaborative efforts to strengthen situational awareness for cyber and physical security while providing timely and coordinated information to industry. In addition, industry should review its planning and operational practices to mitigate potential vulnerabilities to the BPS.	Through the E-ISAC, NERC continues to monitor and disseminate timely cyber and physical security information for its members. NERC also collaborates to strengthen situational awareness through an agreement with the European Union (EU) to share lessons learned and the hosting and participation in situational awareness and grid security conferences in addition to the biennial GridEx exercise.

Ongoing Recommendations

Table 8.3: Ongoing Recommendations				
Item Reference	Finding SOR Report Year	Key Finding SOR Reference	Recommendations	Actions Taken to Date
6	2015	Page 31 Paragraph 2	The collected data (transmission related events resulting in load loss) does not indicate whether load loss during an event occurred as designed. Data collection will be refined in the future for this metric to allow enable data grouping into categories, such as separating load	NERC, PAS, and the TADSWG are currently evaluating data collection and methods that may be enhanced to provide increased awareness of year-over-year trends when load loss occurs during transmission events. These efforts may include collaboration with IEEE and industry forums. This is included in PAS annual reliability metrics review process.

Table 8.3: Ongoing Recommendations

Item Reference	Finding SOR Report Year	Key Finding SOR Reference	Recommendations	Actions Taken to Date
			loss as designed from unexpected firm load loss. Also, differentiating between load losses as a direct consequence of an outage compared to load loss as a result of an operator-controlled action to mitigate an IROL/SOL exceedance should be considered.	
7	2015	Page 32 Paragraph 1	The ERSWG has recommended a measure that was approved by the OC and PC for data collection and testing. This may support development of new voltage and reactive support metrics going forward.	The ERSWG Measures Framework Report contained a proposed measure 7, which was assigned to PAS to develop the necessary data collection processes to allow a test of measure 7 as a potential future voltage and reactive metric. During 2016, PAS developed and conducted a voluntary data collection and released the data for analysis to the SAMS.
8	2015	Page 43 Paragraph 4	Since monitoring the changes that occurred in 2014 versus prior years, the time range categories for IROL exceedances may need to be reviewed. Based on this anticipated result (that monitoring granularity has increased, which may result in a variance over history) the parameters for reporting on Time Range 1 should be examined to ensure that the correct information is being captured.	The TADSWG is currently evaluating data collection and methods that may be enhanced to provide increased awareness of year-over-year trends when load loss occurs during transmission events. Also, the Methods for Establishing IROLs Task Force (MEITF) is currently reviewing consistency of IROL exceedance criteria and may be recommending changes to the IROL exceedance metric.

Table 8.3: Ongoing Recommendations				
Item Reference	**Finding SOR Report Year**	**Key Finding SOR Reference**	**Recommendations**	**Actions Taken to Date**
9	2016	Page 1 Key Finding 2	NERC should consider performing daily SRI calculations on a regional basis to investigate the feasibility of correlating performance with regional weather data.	NERC and PAS are examining interconnection level daily SRI calculations prior to developing possible daily SRI calculations on the regional level.
10	2016	Page 1 Key Finding 3	NERC should provide focus on HP training and education through conferences and workshops that increase knowledge of possible risk scenarios.	NERC continues to host HP workshops to enhance awareness of the HP impact on system risk.
11	2016	Page 2 Key Finding 5	NERC should provide leadership in collaborative efforts to improve system model validation, particularly dynamic models, including the use of synchrophasor and other advanced technology.	Several modeling improvement initiatives have begun. The Synchronized Measurement Subcommittee and the Power Plant Modeling & Verification Task Force have been created to implement and monitor several modeling initiatives. There have also been a number of reliability guidelines and technical reference documents prepared to enhance modeling efforts.
12	2016	Page 2 Key Finding 6	The ERO should lead efforts to monitor the impacts of resource mix changes with concentration on the following: • ERS measures for frequency and voltage support that have been developed and adopted • Methods to increase the population and capability of resources providing frequency response, especially under the scenario that conventional generation continues	The ERSWG continues to develop implementation plans for various essential reliability service measures.

Table 8.3: Ongoing Recommendations				
Item Reference	Finding SOR Report Year	Key Finding SOR Reference	Recommendations	Actions Taken to Date
			to be replaced with variable energy resources • Reliability of reactive power generators, such as static var compensators(SVCs), FACTS devices, and synchronous condensers when applied to replace the voltage support function of retiring conventional generators, such as low-voltage ride-through • Protection for these devices, as well as compatibility and coordination with other BPS protection and controls	

Appendix A: Statistical Analysis of SRI Assessment

This appendix contains detailed data analysis supporting the SRI assessment in Chapter 3. NERC staff has statistically analyzed the daily SRI for 2010–2016 to compare total SRI year-over-year differences as well as differences within the individual generation, transmission, and load loss components. Differences by season have also been investigated.

SRI Performance by Year

Tests indicate statistically significant changes among annual distributions of SRI. ANOVA analysis found that 2011 performance was the best SRI since 2010. Moreover, the difference with all other years was statistically significant.[85] The 2016 SRI performance was statistically similar to 2013 and 2015; statistically better than in 2010, 2012, and 2014, but worse than 2011. The descriptive statistics of the annual distributions of SRI are listed in **Table A.1**.

Table A.1: Descriptive Statistics of Daily SRI by Year

Year	N	Mean	Standard Deviation	Minimum	Maximum	Median
2010	365	1.74	0.61	0.59	4.64	1.7
2011	365	1.5	1.04	0.48	13.97	1.34
2012	366	1.78	0.81	0.55	8.87	1.65
2013	365	1.67	0.60	0.46	4.06	1.57
2014	365	1.85	0.87	0.68	11.14	1.72
2015	365	1.67	0.56	0.69	4.47	1.57
2016	366	1.62	0.50	0.57	3.60	1.55

The relative SRI performance by year is further visible in the boxplot representations of **Figure A.1**. The year 2011 was the best as measured by median as well as mean. This is in spite of the relatively large standard deviation with outliers that included the September 8, 2011, load shed event and the February 2, 2011, cold weather load loss event.

[85] ANOVA with Fisher's Least Significant Difference test at the significance level of 0.05.

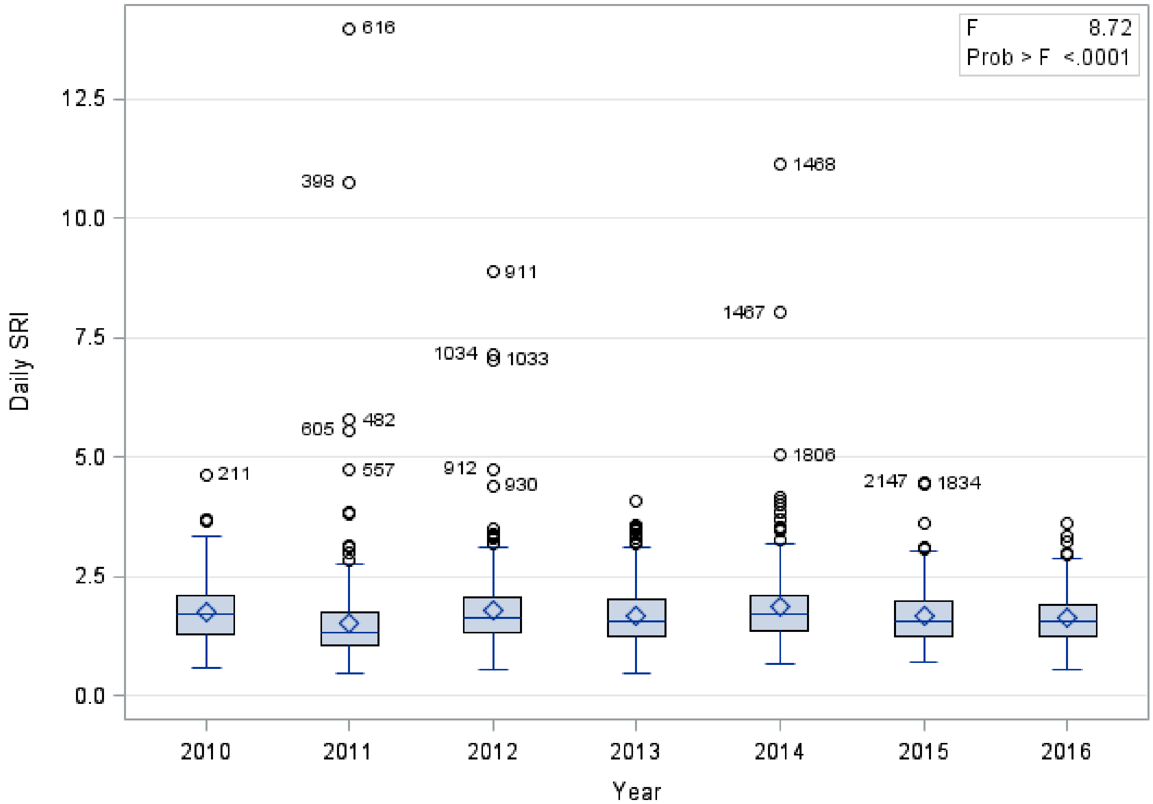

Figure A.1: Boxplot of SRI Distribution by Year

The performance of each year statistically compared to every other year is depicted in **Table A.2** below. If no reference to statistical significance is made within the table, it is assumed to be statistically significant.[86]

[86] At significance level 0.05.

Table A.2: Pairwise Comparison of SRI by Year						
	Compared to Year					
Base Year	2011	2012	2013	2014	2015	2016
2010	2011 Better	No Statistically Significant Difference	No Statistically Significant Difference	2010 Better	No Statistically Significant Difference	2016 Better
2011		2011 Better	2011 Better	2011 Better	2011 Better	2011 Better
2012			2013 Better	No Statistically Significant Difference	2015 Better	2016 Better
2013				2013 Better	No Statistically Significant Difference	No Statistically Significant Difference
2014					2015 Better	2016 Better
2015						No Statistically Significant Difference

Performance of SRI Components by Year

The descriptive statistics of the annual distributions of the weighted generation component of the daily SRI are listed in **Table A.3**.

Table A.3: Descriptive Statistics of Weighted Generation SRI Component by Year						
Year	N	Mean	Standard Deviation	Minimum	Maximum	Median
2010	365	1.03	0.34	0.29	2.67	1.01
2011	365	0.72	0.29	0.12	3.00	0.69
2012	366	1.12	0.36	0.30	2.92	1.08
2013	365	1.10	0.33	0.29	2.11	1.08
2014	365	1.29	0.72	0.43	9.80	1.16
2015	365	1.14	0.41	0.43	3.97	1.09
2016	366	1.12	0.36	0.38	2.64	1.11

Tests indicate statistically significant changes among annual distributions of the generation component of the daily SRI. ANOVA analysis shows that all pairwise annual differences in the average generation component values are statistically significant except between years 2012 and 2013, 2012 and 2015, 2012 and 2016, 2013 and 2015, 2013 and 2016, and 2015 and 2016. The relative performance of the generation component by year is further displayed in **Figure A.2**, where 2011 was the best as measured by median as well as mean, and 2014 was the worst with the largest average, median, and standard deviation of the generation component.

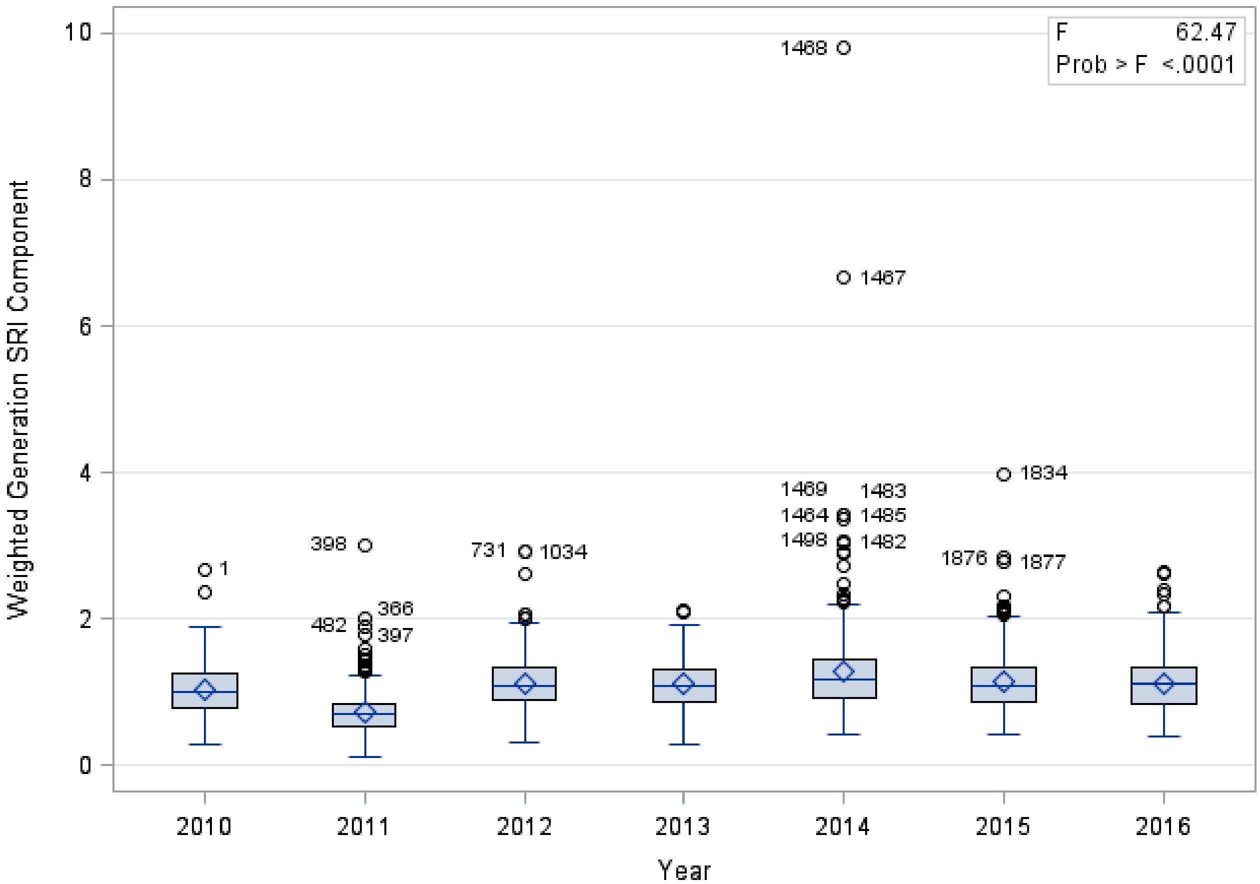

Figure A.2: Boxplot of Distribution of Generation SRI Component by Year

The descriptive statistics of the annual distributions of the transmission component of the daily SRI are listed in **Table A.4**.

Table A.4: Descriptive Statistics of Weighted Transmission SRI Component by Year

Year	N	Mean	Standard Deviation	Minimum	Maximum	Median
2010	365	0.55	0.39	0.06	3.17	0.48
2011	365	0.55	0.38	0.03	3.53	0.46
2012	366	0.50	0.38	0.00	3.35	0.43
2013	365	0.42	0.32	0.00	2.20	0.33
2014	365	0.42	0.27	0.05	1.85	0.37
2015	365	0.40	0.26	0.03	1.78	0.33
2016	366	0.40	0.23	0.04	2.33	0.37

Tests indicate statistically significant changes among annual distribution of the transmission component of the daily SRI. ANOVA analysis shows that the years 2010, 2011, and 2012 were worse than the years 2013, 2014, 2015, 2016 (all pairwise differences between the groups are statistically significant). The first three years had not only statistically larger averages but also larger medians and standard deviations than the most recent three years. It is important to remember that TADS data collection changed in 2015 to include sustained outages for BPS elements below 200 kV; this change significantly affected both the daily numerator and the denominator of the transmission component from 2015 forward. Therefore, comparisons of the transmission components should be limited to those for the years 2010–2014 or those for the years 2015–present in order to avoid introduction of error. The relative performance of the transmission component by year is further illustrated by **Figure A.3**.

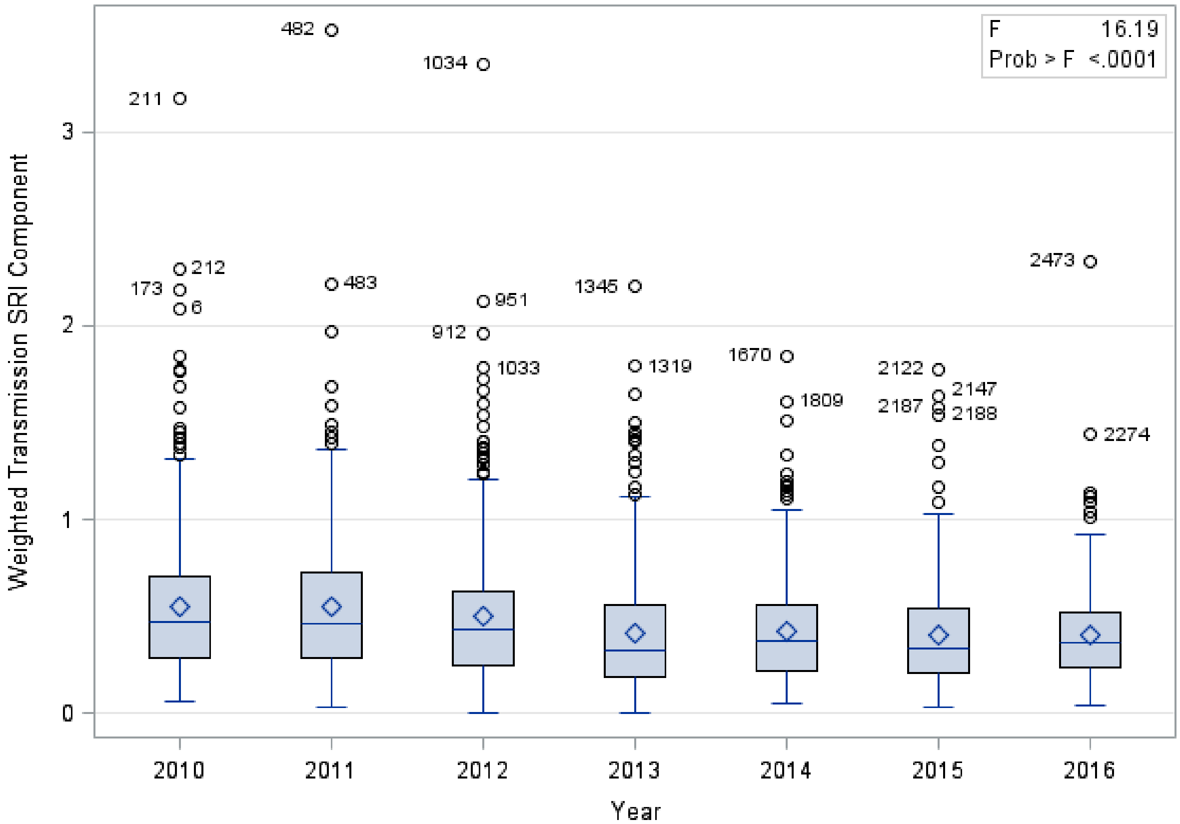

Figure A.3: Boxplot of Distribution of Transmission SRI Component by Year

The descriptive statistics of the annual distribution of the load loss component of the daily SRI are listed in **Table A.5**.

Table A.5: Descriptive Statistics of Weighted Load Loss SRI Component by Year						
Year	N	Mean	Standard Deviation	Minimum	Maximum	Median
2010	365	0.16	0.18	0.00	1.62	0.11
2011	365	0.23	0.77	0.00	11.98	0.11
2012	366	0.17	0.35	0.00	4.88	0.08
2013	365	0.15	0.24	0.00	2.32	0.08
2014	365	0.14	0.25	0.00	3.59	0.07
2015	365	0.13	0.15	0.00	1.72	0.09
2016	366	0.09	0.10	0.00	0.84	0.07

Tests indicated statistically significant changes among annual distribution of the load loss component of the daily SRI. ANOVA analysis showed that the year 2011 was the worst year with a statistically significantly larger average daily load loss component than any other year. 2016 was the best year with the smallest median and variance and statistically better mean than in 2010, 2011, 2012, and 2013. The relative performance of the load loss component by year is further illustrated by **Figure A.4**.

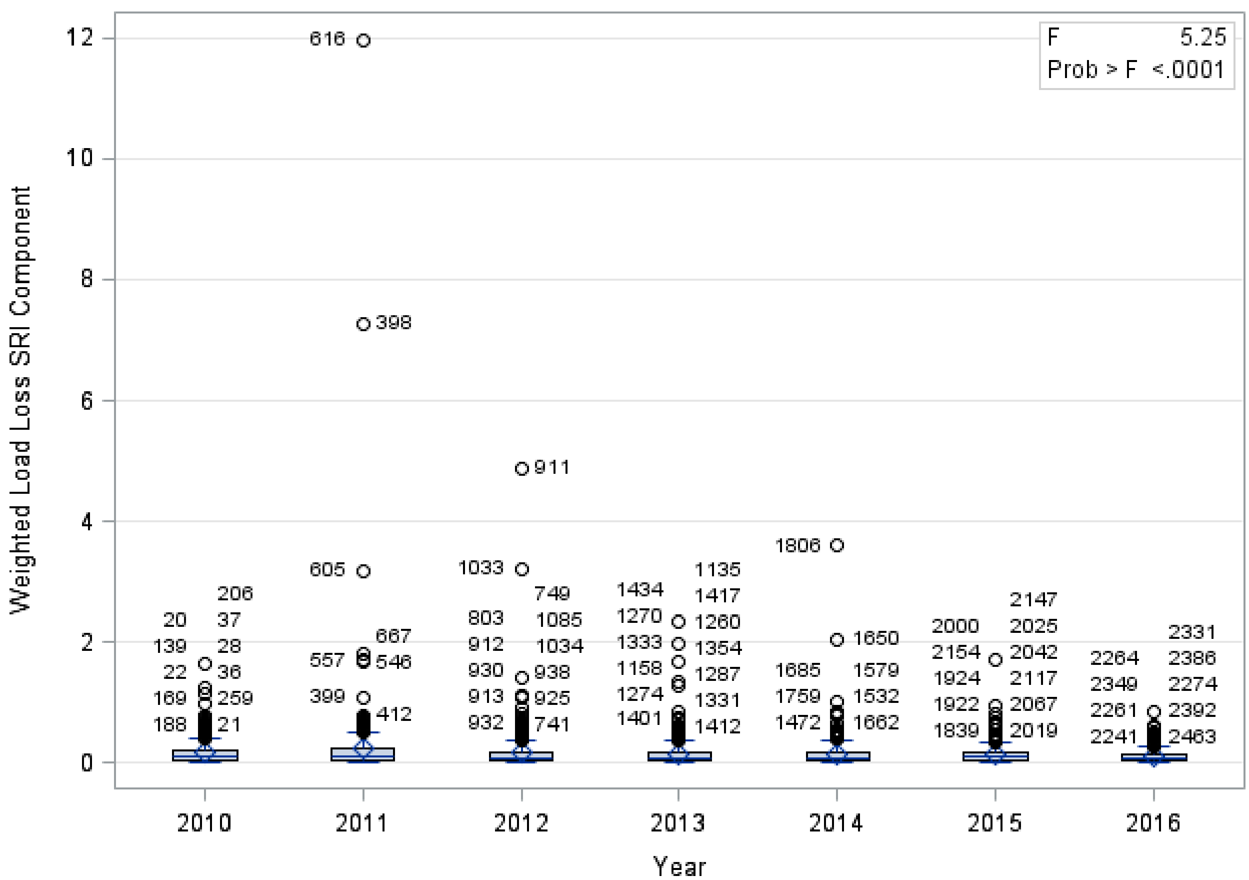

Figure A.4: Boxplot of Distribution of Load Loss Component of SRI by Year

Seasonal Performance of SRI

In **Figure A.5**, the daily performance of SRI is shown over the seven-year history along with a time trend line.

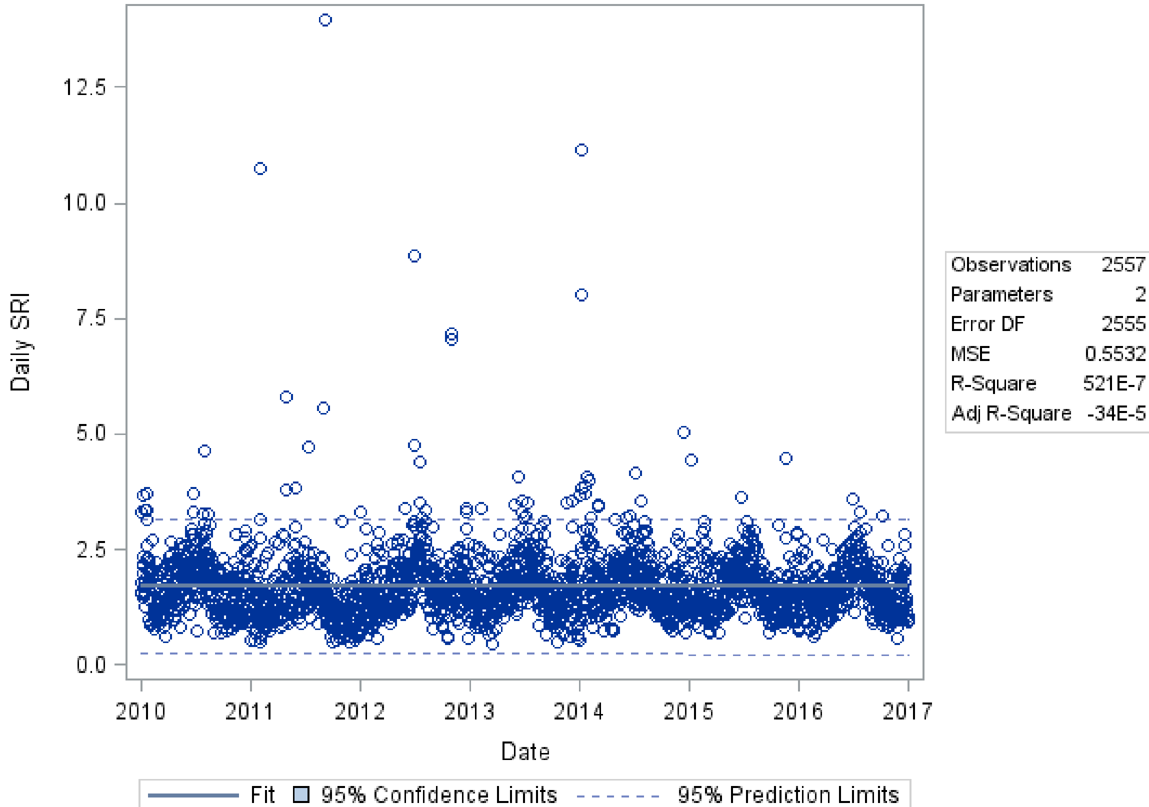

Figure A.5: Scatter Plot for SRI 2010–2016

The time trend line has a negative slope that is not statistically significant (p = 0.72). The same result can be drawn for the correlations analysis: on average, daily SRI has been flat from 2010–2016.

Analysis of the seasonal performance reveals statistically significant differences in SRI by season. The fall SRI has the best performance, the summer SRI has the worst, and spring and winter SRIs are statistically similar. **Table A.6** shows the statistics by season based on the 2010–2016 data.

Table A.6: Descriptive Statistics of SRI by Season

Season	N	SRI				
		Mean	Standard Deviation	Minimum	Maximum	Median
Winter	633	1.63	0.87	0.49	11.14	1.49
Spring	644	1.63	0.52	0.46	5.78	1.57
Summer	642	2.04	0.66	0.69	8.87	1.96
Fall	638	1.45	0.75	0.48	13.97	1.37

Tests[87] indicate that all differences in the seasonal, expected SRI are statistically significant except those for winter and spring, which are illustrated in **Figure A.6**.

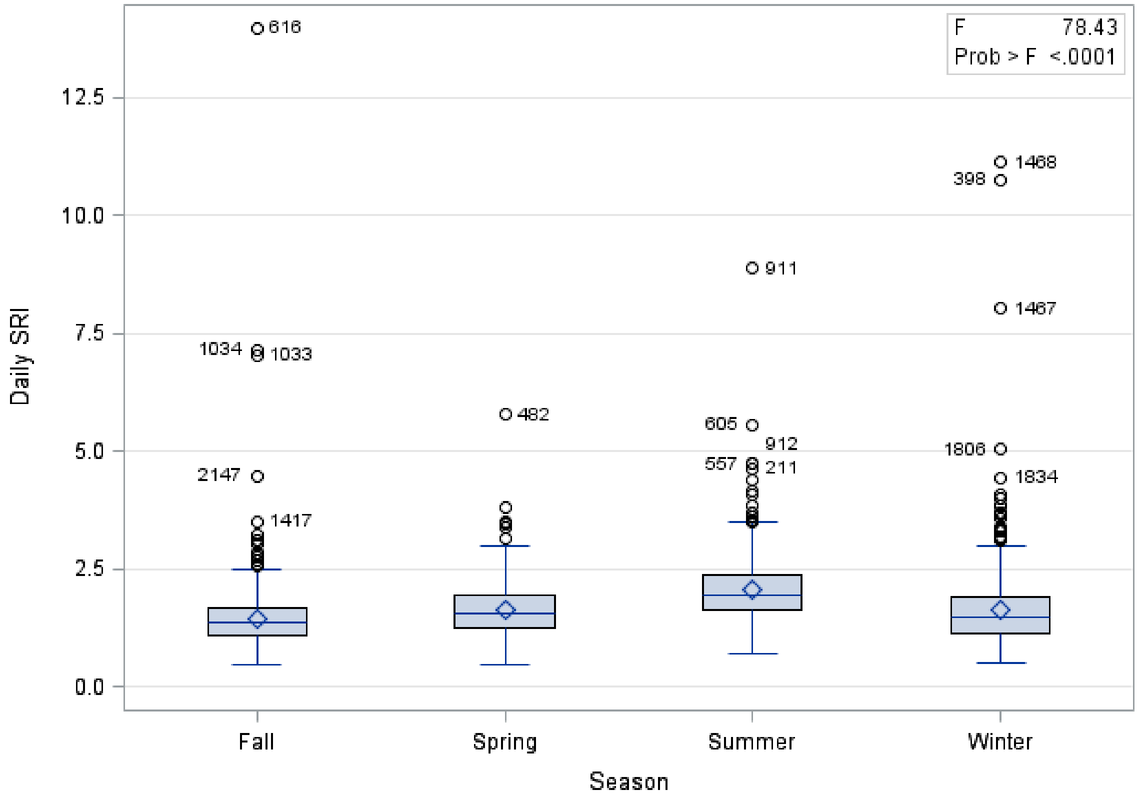

Figure A.6: Boxplot for SRI by Season 2010–2016

[87]ANOVA with Fisher's Least Significant Difference test at the significance level of 0.05.

Appendix B: Statistical Analysis of Transmission Data

The SRI presented in Chapter 3 consists of several weighted risk impact components: generation, transmission, and load loss.[88] The transmission component of the SRI is a weighted factor of the impact of a given day's transmission outages (as reported in TADS) on the BPS. This appendix provides an analysis of TADS outage events based on their TADS outage initiating or sustained cause(s).

Study Method

The following four sections provide a description of the data analysis methodology used in the appendix to rank transmission outage causes by risk to the transmission system and track TADS data changes by year.

Defining BPS Impact from Transmission Risk

An impact of a TADS event to the BPS reliability is called the Transmission Outage Severity (TOS) of the event. A TADS event TOS is defined by Equations B.1 and B.2, which are aligned to the definition of transmission component of the SRI. . Equation B.1 is used for TADS studies involving ac circuit outage events; Equation B.2 is applied to TADS studies involving both ac circuit and transformer outage events. The severity of a transmission outage is calculated based on its estimated contribution of power flow capacity through TADS transmission element based on voltage class. The average power flow megavolt ampere (MVA) values, or equivalent MVA values, are shown in **Table B.1**. These equivalent MVA values are also applied to the denominator of the TOS equation to normalize the function. For normalization, the denominator in Equation B.1 is defined as the sum of the equivalent MVA's of TADS ac circuit inventory for the same year as the event; similarly, the denominator in Equation B.2 is defined as the sum of the equivalent MVA's of TADS ac circuit and transformer inventory for the same year as the event. This allows comparison of TADS events across years while taking into account the changing number of ac circuits and transformers within the BPS.

$$Transmission\ Outage\ Severity\ (TADS\ AC\ circuit\ outage\ event) = \frac{\sum(Equivalent\ MVA\ of\ AC\ Circuits\ with\ automatic\ outages\ in\ this\ event)}{\sum(Equivalent\ MVA\ of\ ALL\ AC\ Circuits\ in\ TADS\ inventory)} \cdot 1000$$

Equation B.1

$$Transmission\ Outage\ Severity\ (TADS\ AC\ circuit\ or\ Transformer\ outage\ event) = \frac{\sum(Equivalent\ MVA\ of\ AC\ Circuits\ and\ Transformers\ with\ automatic\ outages\ in\ this\ event)}{\sum(Equivalent\ MVA\ of\ ALL\ AC\ Circuits\ and\ Transformers\ in\ TADS\ inventory)} \cdot 1000$$

Equation B.2

[88] http://www.nerc.com/docs/pc/rmwg/pas/index_team/sri_equation_refinement_may6_2011.pdf, pp. 2-3.

Table B.1: Equivalent MVA Values of TADS Elements		
Voltage Class	**AC Circuits**	**Transformers**
100–199 kV	200	100
200–299 kV	700	259
300–399 kV	1,300	518
400–599 kV	2,000	1,034
600–799 kV	3,000	1,441

Impact of the TADS Data Collection Changes

Beginning in 2015, the reporting changed through the *NERC Rules of Procedure 1600 Data Request* so that TADS data collection would align with the implementation of the FERC approved BES definition.[89] Two additional voltage classes were amended, namely, less than 100 kV and 100–199 kV.

Changes to TADS data collection had an impact on existing metrics and provides for expanded analysis. **Table B.2** illustrates the ac circuit data collected at the various voltage classes available to support outage metrics. For example, discontinuation of the nonautomatic planned outage data no longer supports a total outage availability (or unavailability) metric. Sustained outages are the only common outages collected at all voltage classes above and below 200 kV.

Table B.2: TADS BES Outage Data Collection by AC Voltage Class (Effective Jan 1, 2015)				
AC Voltage Class	**Automatic Outages**		**Nonautomatic Outages**	
	Sustained	**Momentary**	**Planned**	**Operational**
Below 100 kV	Yes	No	No	No
100–199 kV	Yes	No	No	No
200–299 kV	Yes	Yes	No	Yes
300–399 kV	Yes	Yes	No	Yes
400–599 kV	Yes	Yes	No	Yes
600–799 kV	Yes	Yes	No	Yes

Legend	
Yes	Outage data collected for this type of outage and voltage class
No	Outage data not collected for this type of outage and voltage class

[89] http://www.nerc.com/pa/RAPA/Pages/BES.aspx

The following six study cases were analyzed for TADS data sets described above. The results of the six ICC studies follow in this Appendix:

1. 200 kV+ TADS ac circuit events (momentary and sustained) from 2012–2016
2. 200 kV+ ac circuit common or dependent-mode (CDM) events, which resulted in multiple transmission element outages from 2012–2016
3. 200 kV+ TADS ac circuit events (momentary and sustained) by Region from 2012–2016
4. 100 kV+ TADS ac circuit sustained events from 2015–2016
5. 100 kV+ TADS ac circuit and transformer 2016 sustained events
6. 100 kV+ sustained 2015–2016 outages analyzed by sustained cause code.

The less than 200 kV sustained automatic outage data set was not included in study cases 1–3 to allow for a valid year-over-year comparative analysis of the 200 kV+ data set for the years 2012–2016. In Studies 1–4 and 6, the TOS of TADS events is calculated by using Equation B.1. In Study 5 it is by using Equation B.2.

Determining Initiating Causes and Modification Method

TADS collects automatic outages[90] and operational outages.[91] A TADS event is a transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS events are categorized by ICC. These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity. The procedure illustrated in **Figure B.1** is used to determine a TADS event's ICCs. The procedure that defines ICCs for a TADS event allows ICC assignment to a majority of transmission outage events recorded in TADS.

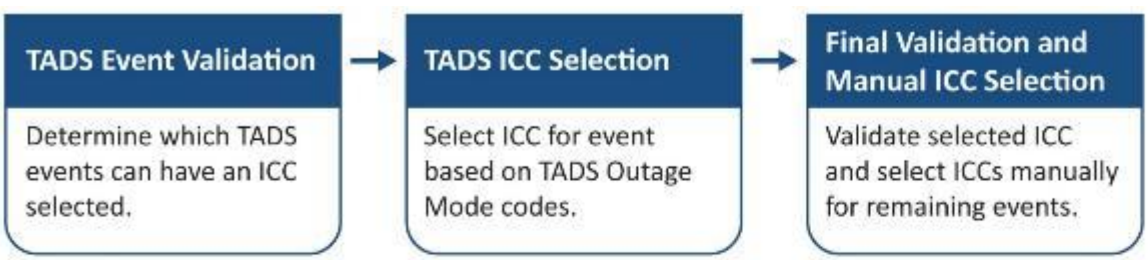

Figure B.1: TADS Event Initiating Cause Code Selection Procedure

Prior to *State of Reliability 2017,* reports have analyzed the TADS data set and TADS-defined ICCs. The *State of Reliability 2013–2016* reports also included analysis based on an augmented data set that defined changes in ICCs to further distinguish normal clearing events from abnormal clearing events. Two TADS ICCs are impacted: Human Error and Failed Protection System Equipment.

- TADS Human Error ICC is subdivided by type codes, which first became available in 2012. Using the type codes in the consequent *State of Reliability* reports, data for two specific type codes related to protection system misoperations have been removed from the Human Error ICC and added to the Failed Protection

[90] An outage that results from the automatic operation of a switching device, causing an element to change from an in-service state to a not in-service state. Single-pole tripping followed by successful ac single-pole (phase) reclosing is not an Automatic Outage.
[91] A Non-Automatic Outage for the purpose of avoiding an emergency (i.e., risk to human life, damage to equipment, damage to property) or to maintain the system within operational limits and that cannot be deferred. Includes Non-Automatic Outages resulting from manual switching errors.

System Equipment ICC. Those type codes are 61 dependability[92] (failure to operate) and 62 security[93] (unintended operation).

- TADS Failed Protection System Equipment ICC, plus the Human Error type code 61 and 62 data, are added together in a new or augmented ICC labeled "Misoperation" in each *State of Reliability* report.

The *State of Reliability 2013–2014* reports have revealed that analyzing data based on both data sets (TADS ICCs and TADS augmented ICCs to include the Misoperation cause code) has not provided additional information. Therefore, starting with the 2015 report, the TADS data and analyses have been based on the augmented ICC data set, which currently contains five years of data. In the 2017 report, references to ICC mean the augmented ICC as described above.

Determining Relative Risk

The process of the statistical analysis (performed to identify top causes to transmission risk) is demonstrated in **Figure B.2**. After completing Step 1 (quantifying an event impact by TOS) and Step 2 (assigning ICC's to TADS events), NERC staff determined in Step 3 the correlation between each ICC and TOS. Statistically significant relationships between several ICC's and TOS were then determined. Sample distributions were also studied to determine any statistically significant pair-wise differences in expected TOS between ICCs. At Step 4, the relative risk was calculated for each ICC group and then ranked by risk to the transmission system. Where applicable, year-to-year changes in TOS and relative risk are evaluated.

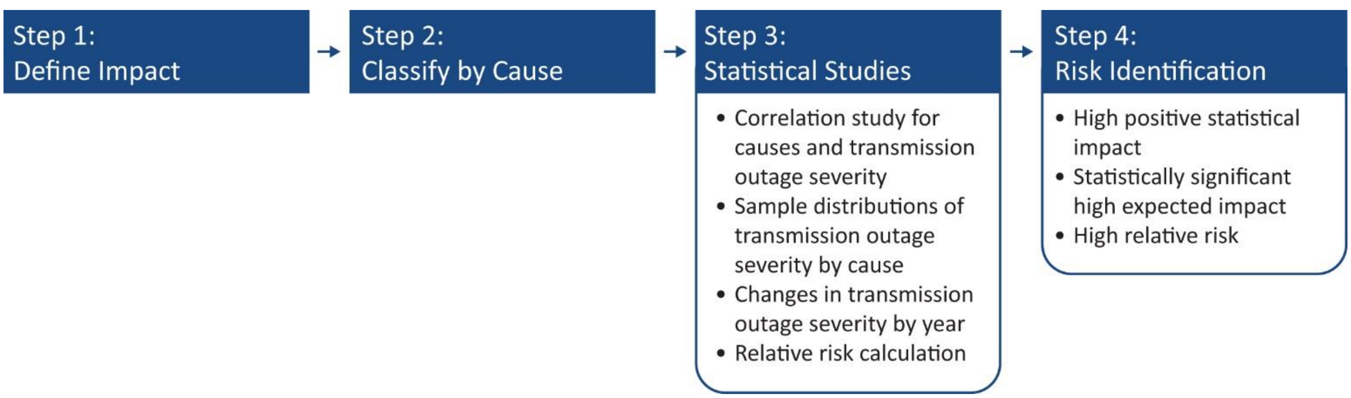

Figure B.2: Risk Identification Method

To study the relationship between ICCs and the TOS for TADS events, NERC investigated the statistical significance of the correlation between TOS and the indicator function[94] of a given ICC.[95] The test is able to determine a statistically significant positive or negative correlation between ICC and TOS.

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[92] Event Type 61 Dependability (failure to operate): one or more automatic outages with delayed fault clearing due to failure of a single protection system (primary or secondary backup) under either of these conditions:
- Failure to initiate the isolation of a faulted power system element as designed, or within its designed operating time, or
- In the absence of a fault, failure to operate as intended within its designed operating time.

[93] Event Type 62 Security (unintended operation): one or more automatic outages caused by improper operation (e.g., overtrip) of a protection system resulting in isolating one or more TADS elements it is not intended to isolate, either during a fault or in the absence of a fault.

[94] The indicator function of a given ICC assigns value 1 to an event with this ICC and value 0 to the rest of the events.

[95] For each ICC, a null statistical hypothesis on zero correlation at significance level 0.05 was tested. If the test resulted in rejection of the hypothesis, it is concluded that a statistically significant positive or negative correlation between an ICC and transmission severity exists; the failure to reject the null hypothesis indicates no significant correlation between ICC and transmission severity.

Distributions of TOS for the entire dataset were examined separately for events with a given ICC. A series of t-tests[96] were performed to compare the expected TOS of a given ICC with the expected outage severity of the rest of the events at significance level of 0.05. Then the Fisher's Least Square Difference[97] method was applied to determine statistically significant[98] differences in the expected TOS for all pairs of ICCs.

Statistically significant differences in the expected TOS for each ICC group were analyzed for each year of data. This showed if the average TOS for a given ICC group had changed over time.

The relative risk was calculated for each ICC group. The impact of an outage event was defined as the expected TOS associated with a particular ICC group. The probability that an event from a given group initiates during a given hour is estimated from the frequency of the events of each type without taking into account the event duration. The risk per hour of a given ICC was calculated as the product of the probability per hour and the expected severity (impact) of an event from this group. The relative risk was then defined as the percentage of the risk associated with each ICC out of the total (combined for all ICC events) risk per hour. The risk profiles of TADS events initiated by common causes are visualized in Figure 3.7 and Figure 3.8, which summarize the results of correlational, distributional, and risk ranking analyses.

AC Circuit Event Statistics by Year

There are 27,405 TADS ac circuit events with ICCs assigned, comprising 99.9 percent of the total number of TADS events for the years 2012–2016. These events contribute 99.5 percent of the total calculated TOS of the database calculated by Equation B.1 without taking into account transformer outages. **Table B.3** provides the corresponding event statistics by year.

Table B.3: TADS AC Circuit Outage Events Summary (2012–2016)

Summary	2012	2013	2014	2015	2016	2012–2016
Number of TADS Events	3,753	3,557	3,477	7,936	8,721	**27,444**
Number of Events with ICC Assigned	3,724	3,557	3,467	7,936	8,721	**27,405**
Percentage of Events with ICC Assigned	99.2%	100.0%	99.7%	100.0%	100.0%	**99.9%**
TOS all TADS Events	612.4	506	448.2	468.8	489.9	**2,525**
TOS of TADS Events with ICC Assigned	602.1	506	445	468.8	489.9	**2,512**
Percentage of TOS of Events with TADS ICC Assigned	98.3%	100%	99.3%	100%	100%	**99.5%**

[96] For t-test, see D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 361-369.

[97] For Fisher's Least Significance Difference (LSD) method or test, see D. C. Montgomery and G. C. Runger, Applied Statistics and Probability for Engineers. Fifth Edition. 2011. John Wiley & Sons. Pp. 524-526.

[98] At significance level of 0.05.

The increased number of events from 2015 reflects the changes in TADS data collection and includes sustained outages of the 100–199 kV ac circuits. For comparison, in 2012–2014, a TADS ac circuit event in North America started, on average, every two hours and 26 minutes, while in 2015—2016 a TADS ac circuit event started, on average, every one hour and three minutes because more events have become reportable. However, the total TOS of all TADS ac circuit events did not increase dramatically in 2015. This is because of the denominator in Equation B.1 increased due to the 2015 inventory increase and events on 100–199 kV ac circuits have a smaller TOS contribution when compared with other events (as reflected by equivalent MVA values in Table B.1).

Study 1: TADS Sustained and Momentary Events for 200 kV+ AC Circuits (2012–2016)

Events with Common ICC by Year and Estimates of Event Probability

Table B.4 lists annual counts and hourly event probability of TADS events by ICC. The six largest ICC groups combined amount to 76 percent of TADS events for 200 kV+ for the most recent five years. With the addition of 2016 data, the ICC of Foreign Interference replaced Failed AC Substation Equipment in the top six ICCs.

Almost all TADS ICC groups have sufficient data available to be used in a statistical year-to-year analysis. Only three ICCs (Vegetation; Vandalism, Terrorism, or Malicious Acts; and Environmental) do not have sufficient size for reliable statistical inferences. Therefore, these ICC groups are combined into a new group, named "Combined Smaller ICC Groups Study 1-3," that can be statistically compared to every other group and also studied with respect to annual changes of TOS.

Using the TOS measure and TADS event ICCs, it is possible to statistically analyze the most recent five years of TADS data (2012–2016). For TADS events initiated by a common cause, the probability[99] of observing the initiation of an event during a given hour is estimated using the corresponding historical event occurrences reported in TADS. Namely, the event occurrence probability is the total number of occurrences for a given type of event observed during the historical data period divided by the total number of hours in the same period. Therefore, the sum of the estimated probabilities for all events is equal to the estimated probability of any event during a given hour.

Table B.4: TADS 200 kV+ AC Circuit Outage Events and Hourly Event Probability by ICC (2012–2016)

Initiating Cause Code	2012	2013	2014	2015	2016	2012–2016	Event Initiation Probability/Hour
Lightning	852	813	709	783	733	**3,890**	0.089
Unknown	710	712	779	830	773	**3,804**	0.087
Weather (excluding lightning)	446	433	441	498	638	**2,456**	0.056
Failed AC Circuit Equipment	261	248	224	255	362	**1,350**	0.031
Misoperation	321	281	314	165	249	**1,330**	0.030
Foreign Interference	170	181	226	274	258	**1,109**	0.025
Failed AC Substation Equipment	248	191	223	221	214	**1,097**	0.025
Contamination	160	151	149	154	289	**903**	0.021

[99] Probability is estimated using event occurrence frequency of each ICC type without taking into account the event duration.

Table B.4: TADS 200 kV+ AC Circuit Outage Events and Hourly Event Probability by ICC (2012–2016)							
Initiating Cause Code	**2012**	**2013**	**2014**	**2015**	**2016**	**2012–2016**	**Event Initiation Probability/Hour**
Human Error (w/o Type 61 OR Type 62)	212	191	149	132	153	**837**	0.019
Power System Condition	77	109	83	96	81	**446**	0.010
Fire	106	130	44	65	72	**417**	0.010
Other	104	64	77	77	78	**400**	0.009
Combined Smaller ICC Groups Study 1-3	57	53	49	37	47	**196**	0.006
Vegetation	43	36	39	32	34	**184**	0.004
Vandalism, Terrorism, or Malicious Acts	10	9	8	1	7	**35**	0.001
Environmental	4	8	2	4	6	**24**	0.001
All with ICC Assigned	3,724	3,557	3,467	3,587	3,947	**18,282**	0.417
All TADS Events	3,753	3,557	3,477	3,587	3,947	**18,321**	0.418

In 2016, there was a significant increase in the number of events initiated by Weather (excluding lightning), Failed AC Circuit Equipment, Misoperation, and Contamination. This drove an overall increase in the number of outage events. However, the two biggest ICC groups, Lightning and Unknown, had noticeable decreases in the number of events from 2015 to 2016.

Correlation between ICC and TOS

To study a relationship between ICC and TOS of TADS events, the statistical significance of the correlation between TOS and the indicator function[100] of a given ICC was investigated.[101] A statistically significant positive or negative correlation between ICC and TOS could be determined by the statistical test. There were three key outcomes of all tests as stated here:

- A statistically significant positive correlation of ICC to TOS indicates a greater likelihood that an event with this ICC would result in a higher TOS.
- A significant negative correlation indicates the contrary; in this case, a lower TOS would be likely.
- If no significant correlation is found, it indicates the absence of a linear relationship between ICC and the TOS and that the events with this ICC have an expected TOS similar to all other events from the database.

Figure B.3 shows the correlations between calculated TOS and the given ICC. A red bar corresponds to an ICC with statistically significant positive correlation with TOS, a green bar corresponds to an ICC with statistically significant negative correlation, and a blue bar indicates no significant correlation.

[100] The indicator function of a given ICC assigns value 1 to an event with this ICC and value 0 to the rest of the events.

[101] For each ICC, a null statistical hypothesis on zero correlation at significance level 0.05 was tested. If the test resulted in rejection of the hypothesis, it is concluded that a statistically significant positive or negative correlation between an ICC and transmission outage severity exists; the failure to reject the null hypothesis indicates no significant correlation between ICC and transmission outage severity.

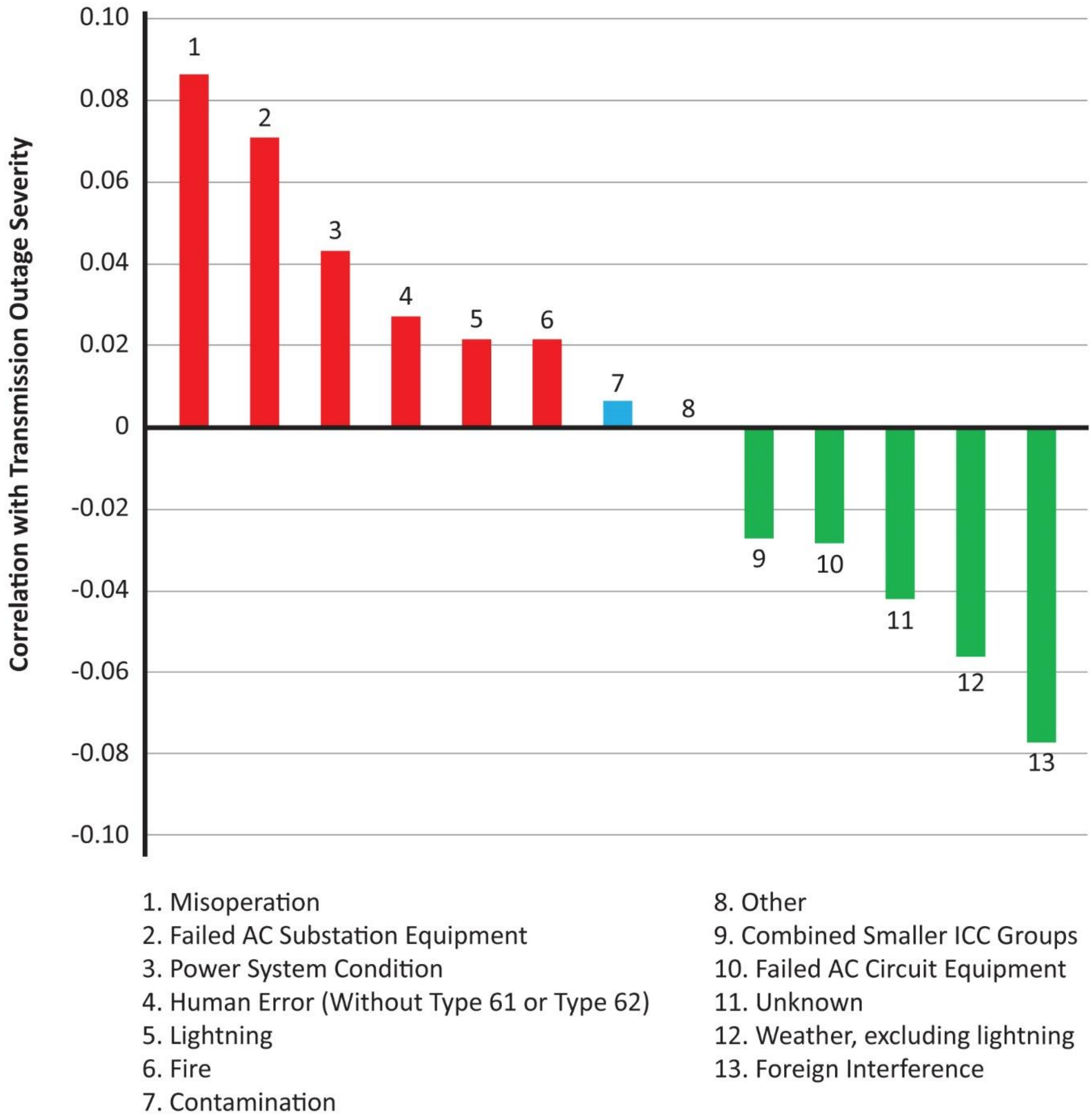


Figure B.3: Correlation between ICC and TOS of 200 kV+ AC Circuit Outage Events (2012–2016)

Distribution of TOS by ICC

The distribution of TOS was studied separately for events with a given ICC and the complete dataset for the five years combined. The sample statistics for TOS are listed in **Table B.5** with the ICCs ordered from the largest average TOS to the smallest.

A series of the Fisher's Least Square Difference tests confirms that the groups of events initiated by Misoperation, Failed AC Substation Equipment, Power System Condition, Fire, Human Error, and Lightning have statistically[102] greater expected severity than other events. It means that when an event initiated by one of these causes occurs, it has a greater impact and a higher risk to the transmission system on average. The tests on homogeneity of variances highlights statistically greater variances (and the standard deviations) for the top three ICC groups and

[102] At significance level 0.05

Human Error as compared with other events. The greater variance can signify additional risk since it implies more frequent occurrences of events with high TOS.

Table B.5 also provides a column that lists ICCs with TOS statistically smaller than for a given ICC referenced by the table's initial column index. For example, Misoperation and Failed AC Substation Equipment initiate events with statistically larger TOS than any other ICC, starting with Fire (indices 4-13). However, differences between the top three groups are not significant, meaning that an individual impact of events from these groups are similar.

Table B.5: Distribution of TOS of 200 kV+ AC Circuit Outage Events by ICC (2012–2016)

Index No.	ICC	Average TOS	Is Expected TOS Statistically Significantly Different than for other Events?	ICC with Statistically Significantly Smaller Average TOS	Standard Deviation of TOS
1	Misoperation	0.153	Larger	4,5,6,7,8,9,10,11,12,13	0.126
2	Failed AC Substation Equipment	0.151	Larger	4,5,6,7,8,9,10,11,12,13	0.110
3	Power System Condition	0.150	Larger	5,6,7,8,9,10,11,12,13	0.133
4	Fire	0.139	Larger	8,9,10,11,12,13	0.082
5	Human Error (w/o Type 61 OR Type 62)	0.137	Larger	6,8,10,11,12,13	0.093
6	Lightning	0.131	Larger	9,10,11,12,13	0.078
7	Contamination	0.130	No	9,10,11,12,13	0.068
	All events	**0.128**	**N/A**	**N/A**	**0.084**
8	Other	0.127	No	11,12,13	0.094
	All with ICC assigned	**0.127**	**N/A**	**N/A**	**0.083**
9	Unknown	0.120	Smaller	11,12,13	0.064
10	Failed AC Circuit Equipment	0.119	Smaller	12,13	0.074
11	Weather (excluding lightning)	0.115	Smaller	13	0.069
12	Combined Smaller ICC Groups Study 1-3	0.108	Smaller	none	0.058
13	Foreign Interference	0.102	Smaller	none	0.056

Average TOS by ICC: Annual Changes

Year-over-year changes in calculated TOS for 200 kV+ ac circuit events by ICC are reviewed next. **Figure B.4** shows changes in the average TOS for each ICC for the 2012–2016 dataset. The groups of ICC events are listed from left to right by descending average TOS for the five years combined. The largest average TOS over the data period was observed for events initiated by Misoperation.

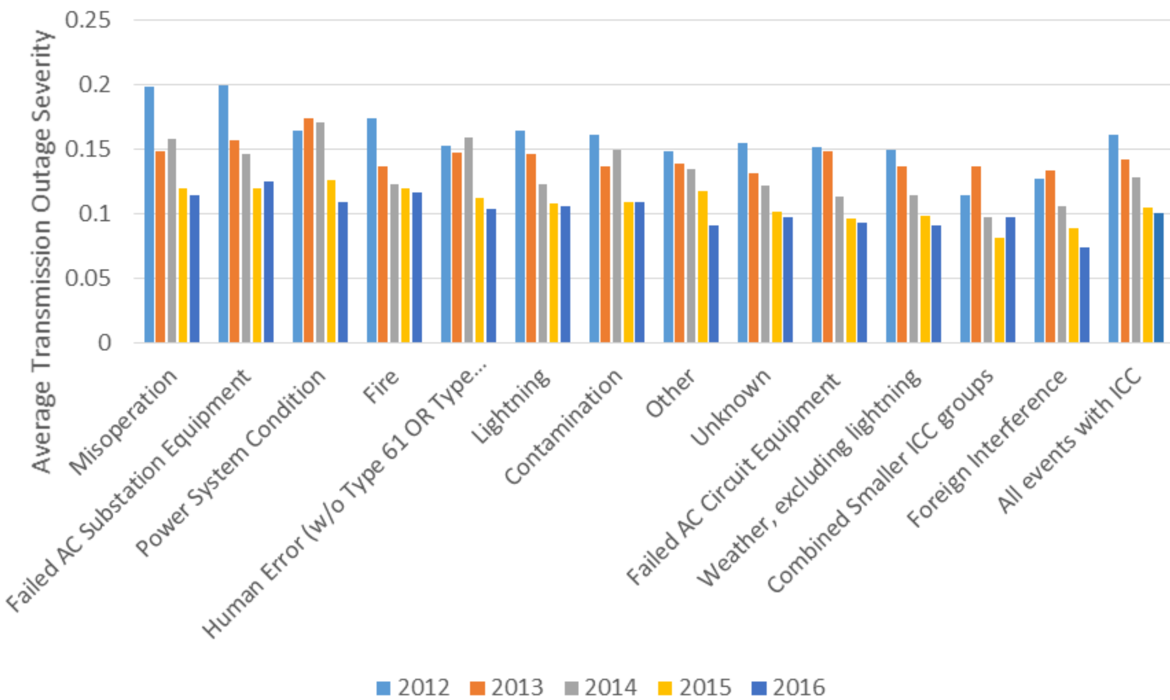


Figure B.4: Average TOS of 200 kV+ AC Circuit Events by ICC and Year (2012–2016)

The noticeable decrease in the average TOS in 2015 for all ICC groups (shown in **Figure B.4**) was due to a larger ac circuit inventory and therefore to a larger total MVA of the ac circuit inventory that is a denominator in the formula for the TOS of a TADS event (Equation B.1). A fair comparison and a valid year-to-year analysis can be performed separately among the 2012–2014 data and between the 2015–2016 data. Compared to 2015, only the ICC group Foreign Interference had a significant change (decrease) in the 2016 average TOS. Overall, the average transmission severity for all events also decreased statistically significantly 2015–2016.

ICC Misoperation has the highest average TOS over the five-year period, but in 2015 and 2016 it ranks third. Another noticeable change in ranking is for the ICC Power System Condition with respect to the average TOS;[103] in 2015, it ranked the first and in 2016 became the fifth.

TOS Risk and Relative Risk of 200 kV+ AC Circuit Outage Events by ICC

The risk of each ICC group can be defined as the total TOS associated with this group. Its relative risk is equal to the percentage of the group TOS in the 2012–2016 database. Equivalently, the risk of a given ICC per hour can be defined as the product of the probability that an event with this ICC initiates during an hour and the expected TOS (impact) of an event from this group. For any ICC group, the relative risk per hour is the same as the relative risk for a year (or any other time period) if estimated from the same dataset.

Relative risk of the 2012–2016 TADS ac circuit events by ICC is listed in **Table B.6**. The probability that an event from a given ICC group initiates during a given hour is estimated from the frequency of the events of each type without taking into account the event duration. Excluding weather-related events and events with unknown ICCs, events initiated by Misoperation, by Failed AC Substation Equipment, and by Failed AC Circuit Equipment had the

[103] Power System Condition is defined as "automatic outages caused by power system conditions such as instability, overload trip, out-of-step, abnormal voltage, abnormal frequency, or unique system configurations (e.g., an abnormal terminal configuration due to existing condition with one breaker already out of service)."

largest shares in the total TOS and contributed 8.7 percent, 7.1 percent, and 6.9 percent respectively to TOS relative risk for the most recent five years.

Power System Condition has a low rank despite having the third largest average TOS of an individual event. This is because there are a small number of events with this ICC, and the occurrences of these events are rare (as reflected by their small probability).

Table B.6: Relative Risk of TADS 200 kV+ AC Circuit Outage Events by ICC (2012–2016)				
Group of TADS Events	Probability that an Event from a Group Starts During a Given Hour	Expected Impact (Expected TOS of an Event)	Risk Associated with a Group Per Hour	Relative Risk by Group
All TADS events 200 kV+	0.418	0.128	0.0534	100%
All 200 kV+ with ICC assigned	0.417	0.127	0.0530	99.4%
Lightning	0.089	0.131	0.0116	21.7%
Unknown	0.087	0.120	0.0104	19.6%
Weather (excluding lightning)	0.056	0.115	0.0065	12.1%
Misoperation	0.030	0.153	0.0046	8.7%
Failed AC Substation Equipment	0.025	0.151	0.0038	7.1%
Failed AC Circuit Equipment	0.031	0.119	0.0037	6.9%
Contamination	0.021	0.130	0.0027	5.0%
Human Error (w/o Type 61 OR Type 62)	0.019	0.137	0.0026	4.9%
Foreign Interference	0.025	0.102	0.0026	4.8%
Power System Condition	0.010	0.150	0.0015	2.9%
Fire	0.010	0.139	0.0013	2.5%
Other	0.009	0.127	0.0012	2.2%
Combined Smaller ICC Groups Study 1-3	0.006	0.108	0.0006	1.1%

Figure B.5 shows year-over-year changes in the relative risk of TADS events by ICC. The groups of ICC events are listed from left to right by descending relative risk for the most recent five years combined. The top two contributors to transmission risk—Lightning and Unknown—had a decrease in relative risk in 2016 due to a decrease in the number (and the frequency) of events as reflected in Table B.4. In contrast, Weather (excluding lightning) had an increase due to a significant (28 percent) increase in the number of the weather-initiated events in 2016.

The relative risk of Misoperation increased from 5.3 percent in 2015 to 7.2 percent in 2016 due to an increase in the number of outage events initiated by Misoperation, still being the second smallest relative risk for the group over the five years. Also, there was a significant increase in the relative risk for the ICCs Failed AC Circuit Equipment and Contamination due to increases in the frequency of these events in 2016.

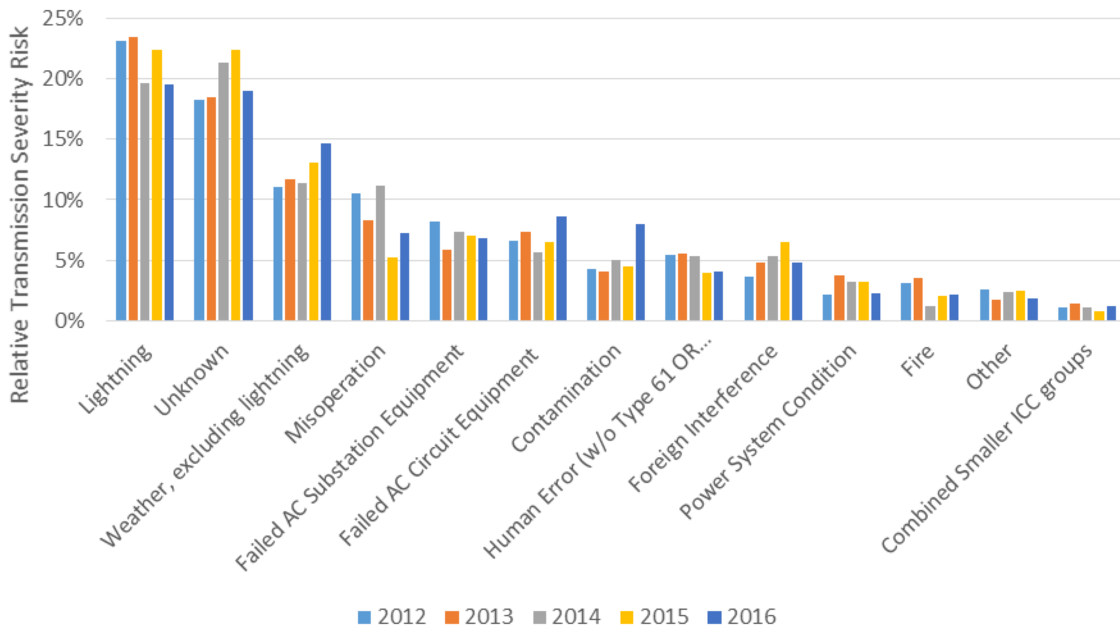


Figure B.5: Relative TOS Risk 200 kV+ AC Circuit Outage Events by ICC and Year (2012–2016)

Study 2: TADS CDM Events for 200 kV+ AC Circuits

Common/Dependent Mode Event ICC Analysis (2012–2016)

TADS also provides information to classify outages as Single Mode or CDM events. A Single-Mode event is defined as a TADS event with a single-element outage. CDM events result in multiple transmission element outages where all outages have one of the mode codes (other than Single Mode) as described in **Table B.7**. These TADS events have a higher TOS than TADS events with a Single-Mode outage. It is important to monitor and investigate CDM events due to their increased potential risk to system reliability.

Table B.7: Outage Mode Codes	
Outage Mode Code	**Automatic Outage Description**
Single Mode	A single-element outage that occurs independently of another automatic outage
Dependent Mode Initiating	A single-element outage that initiates at least one subsequent element automatic outage
Dependent Mode	An automatic outage of an element that occurred as a result of an initiating outage, whether the initiating outage was an element outage or a nonelement outage
Common Mode	One of at least two automatic outages with the same initiating cause code where the outages are not consequences of each other and occur nearly simultaneously
Common Mode Initiating	A common-mode outage that initiates one or more subsequent automatic outages

TADS event are categorized as either a Single Mode event or a CDM event where possible. Some TADS events were entered as a combination of Single Mode outages and other outage modes. These events were manually examined to determine if the event was Single Mode or CDM. For some events, it was not possible to determine whether the event was Single Mode or CDM, nor was it possible to tell the ICC for the event. These events, approximately 0.2 percent of all TADS 200 kV+ events, were removed from the study.

Table B.8 lists numbers of CDM events of 200 kV+ ac circuits by ICC for 2012–2016. There was a total of 2,701 CDM events with 2,664 of these assigned to one of the 15 ICCs. CDM events comprise 14.7 percent of all TADS 200 kV+ events from 2012–2016. The reciprocal of the CDM probability per hour of 0.062 predicts that in NERC's defined BES system of 200 kV+ ac circuits that a CDM event started, on average, every 16 hours and 14 minutes.

Table B.8 provides the population percentage of CDM events in the different ICC groups. These percentages vary greatly. There are only 3.4 percent of CDM events among events initiated by Contamination while the 42.6 percent of events initiated by Power System Condition are CDM events.

Table B.8: CDM Events of 200 kV+ AC Circuits and Hourly Event Probability by ICC (2012–2016)

Initiating Cause Code	CDM events	TADS events 200 kV+	CDM as % of ALL	CDM Event Initiation Probability/Hour
Misoperation	446	1,330	33.5%	0.010
Failed AC Substation Equipment	425	1,097	38.7%	0.010
Lightning	421	3,890	10.8%	0.010
Unknown	238	3,804	6.3%	0.005
Weather (excluding lightning)	213	2,456	8.7%	0.005
Human Error (w/o Type 61 OR Type 62)	190	837	22.7%	0.004
Power System Condition	190	446	42.6%	0.004
Failed AC Circuit Equipment	179	1,350	13.3%	0.004
Foreign Interference	128	1,109	11.5%	0.003
Other	106	400	26.5%	0.002
Fire	70	417	16.8%	0.002
Contamination	31	903	3.4%	0.001
Combined Smaller ICC Groups Study 1-3	27	243	11.1%	0.001
Vegetation	13	184	7.1%	0.0003
Environmental	7	24	29.2%	0.0002
Vandalism, Terrorism, or Malicious Acts	7	35	20.0%	0.0002
With ICC Assigned	2,664	18,282	14.6%	0.061
TADS Events	2701	18321	14.7%	0.062

Annual datasets of CDM events do not have enough observations to track statistically significant year-over-year changes in TOS. Upon combining the three smallest ICC groups (Vegetation; Environmental; and Vandalism, Terrorism, or Malicious Acts) into a new group (Combined Smaller ICC groups), the five-year ICC groups are used for the correlation analysis. Out of all ICCs, only Foreign Interference has a statistically significant (negative) correlation with the indicator of TOS.

The TOS by ICC is analyzed and the distributions of TOS by ICC are statistically compared. The sample statistics for TOS by ICC are listed in Table B.9 (same format as Table B.5). The TOS of the 2012–2016 CDM events of the 200 kV+ ac circuits has a sample mean of 0.191 and a sample deviation of 0.152 shown in the highlighted row. The mean TOS is greater than the 0.128 for all 200 kV+ TADS events in Table B.5 which is not surprising since CDM events involve multiple outages.

Statistical tests determined few statistically significant differences in the average TOS between ICC groups. These results reflect less variability between ICC groups for CDM events than for all events partially due to their smaller sizes. Only three ICC groups have statistically different expected outage severity; events initiated by Lightning have the higher expected severity than the other CDM events while events initiated by Foreign Interference, and events from smaller groups combined have the smaller expected TOS than the other CDM events.

Table B.9 also provides a column that lists ICCs with TOS statistically smaller than for a given ICC referenced by the table's initial column index. For example, Contamination initiates events with statistically larger TOS than ICC Foreign Interference or Combined Smaller ICC groups.

Table B.9: Distribution of TOS of CDM 200 kV+ AC Circuit Outage Events by ICC (2012–2016)

Index No.	ICC	Average TOS	Is Expected TOS Statistically Significantly Different than for Other Events?	ICC With Statistically Significantly Smaller Average TOS	Standard Deviation of TOS
1	Contamination	0.233	No	12, 13	0.186
2	Lightning	0.202	Larger	13	0.139
3	Human Error (w/o Type 61 OR Type 62)	0.195	No	13	0.152
4	Failed AC Circuit Equipment	0.193	No	13	0.134
5	Misoperation	0.192	No	13	0.185
	CDM events	**0.191**	**N/A**	**N/A**	**0.152**
6	Unknown	0.191	No	13	0.137
7	Power System Condition	0.190	No	13	0.180
	CDM with ICC assigned	**0.189**	**N/A**	**N/A**	**0.151**
8	Failed AC Substation Equipment	0.189	N/A	13	0.145
9	Weather (excluding lightning)	0.187	No	13	0.136
10	Fire	0.184	No	13	0.124
11	Other	0.174	No	none	0.145
12	Combined Smaller ICC groups	0.152	Smaller	none	0.086
13	Foreign Interference	0.135	Smaller	none	0.094

The overall transmission risk and relative risk by ICC group for CDM events were calculated and ranked. Table B.10 provides a breakdown of relative risk of CDM events by ICC group.

Group of TADS events	Probability that an Event from a Group Starts During a Given Hour	Expected Impact (Expected TOS of an Event)	Risk Associated with a Group Per Hour	Relative Risk by Group
All TADS 200 kV+	0.418	0.128	0.0534	**100%**
CDM events	0.062	0.191	0.0118	**22.1%**
CDM with ICC assigned	0.061	0.189	0.0115	**21.5%**
Misoperation	0.010	0.192	0.0020	**3.7%**
Lightning	0.010	0.202	0.0019	**3.6%**
Failed AC Substation Equipment	0.010	0.189	0.0018	**3.4%**
Unknown	0.005	0.191	0.0010	**1.9%**
Weather (excluding lightning)	0.005	0.187	0.0009	**1.7%**
Human Error (w/o Type 61 OR Type 62)	0.004	0.195	0.0008	**1.6%**
Power System Condition	0.004	0.190	0.0008	**1.5%**
Failed AC Circuit Equipment	0.004	0.193	0.0008	**1.5%**
Other	0.002	0.174	0.0004	**0.8%**
Foreign Interference	0.003	0.135	0.0004	**0.7%**
Fire	0.002	0.184	0.0003	**0.6%**
Contamination	0.001	0.233	0.0002	**0.3%**
Combined Smaller ICC groups	0.001	0.152	0.0001	**0.2%**

Table B.10: Relative Risk of 200 kV+ AC Circuit CDM Events by ICC (2012–2016)

Analysis of TADS CDM events indicated that events with ICCs of Misoperation, Lightning, and Failed AC Substation Equipment are the three largest contributors to TOS of the 200 kV+ ac circuit events with multiple outages.

Study 3: Regional Entity Transmission Analysis

The following is a study of the TOS of TADS events by Region. This analysis is based on the 2012–2016 TADS data for the 200 kV+ ac circuits and utilizes the general methodology described in the previous sections. Here, a summary of this analysis is introduced and similarities and differences in transmission risk profiles by Region are examined. **Figure B.6** shows the breakdown of NERC-wide inventory, TADS ac circuit events and TOS risk by Region. The breakdown of the number of outage events and total TOS is similar to breakdown of the NERC inventory by ac circuit counts and by ac circuit miles.

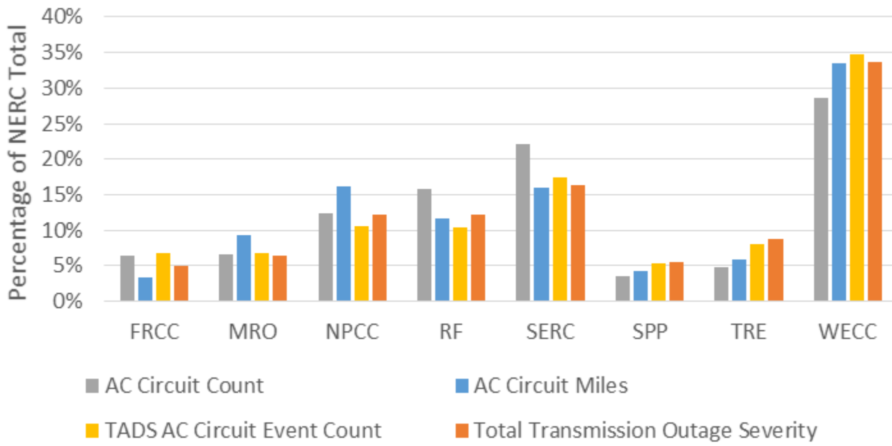


Figure B.6: NERC 200 kV+ AC Circuit Inventory, TADS Events and Breakdown by Region (2012–2016)

The Regional ac circuit inventories differ by count (number of circuits or circuit miles) and by voltage class mix. This may contribute to the significant differences in the average TOS of TADS events between Regions. Since the ac circuit voltage determines the TOS (Equation B.1), outages on systems with higher voltages would have a greater impact.

The TOS by ICC was studied for each Region. A comparative analysis of RE relative risks by ICC is summarized in **Figure B.7**. ICCs are listed from left to right by decreasing relative risk for NERC data.

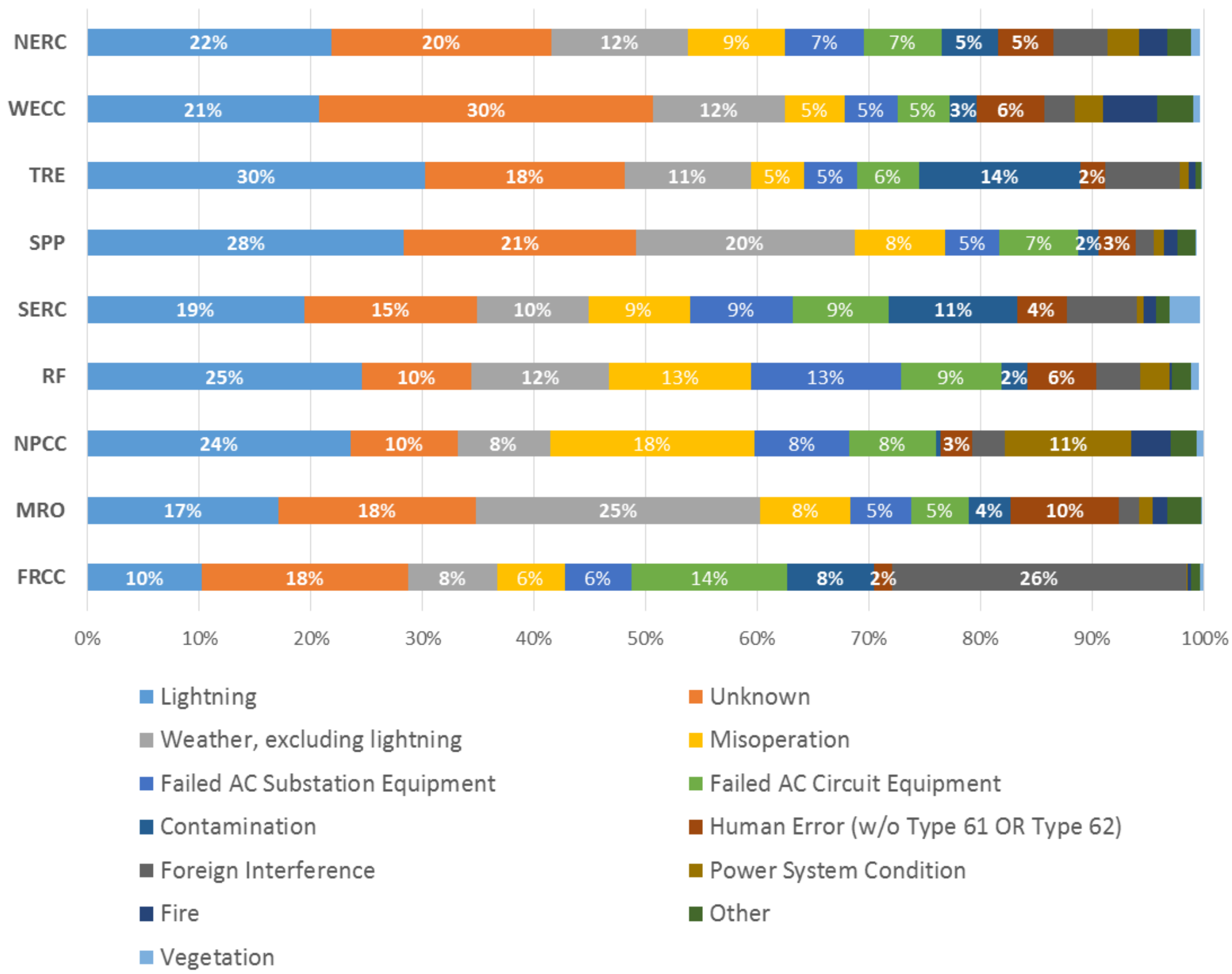


Figure B.7: Relative Transmission Risk of 200 kV+ AC Circuit Outage Events by ICC and Region (2012–2016)

The ICC contributions vary dramatically among Regions for the top NERC ICCs. For example, Misoperation has the highest relative risk in NPCC (18 percent) and the lowest in TRE and WECC (five percent) with other Regions' numbers closer to the NERC average of nine percent. For MRO, SPP, TRE, and WECC, AC Substation Equipment failures resulted in five percent of the total TOS while they contributed 13 percent in RF.

FRCC has a very distinctive profile with a unique risk breakdown. First, the top three ICCs for North America (the two weather-related ICCs and Unknown) comprise only 37 percent of the TOS in FRCC versus 54 percent for NERC. Second, FRCC's top-risk ICC is Foreign Interference, which ranks very low for NERC and other Regions. Note that NERC's top nonweather-related contributors, Misoperation, and Failed AC Substation Equipment, together comprise only 12 percent of FRCC's transmission risk compared with 14 percent for Failed AC Circuit Equipment.

Study 4: TADS Sustained Events of 100 kV+ AC Circuits (2015–2016)

Sustained Events with Common ICC by Year and Estimates of Event Probability

TADS provides information to classify automatic outages as momentary or sustained.[104] A momentary outage is defined as an automatic outage with an outage duration less than one minute. If the circuit recloses and trips

[104] http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx.

again within less than a minute of the initial outage, it is only considered one outage. The circuit would need to remain in service for longer than one minute between the breaker operations to be considered two outages.

A Sustained Outage[105] is defined as an automatic outage with an outage duration of a minute or greater. The definition of Sustained Outage has been extended to a TADS event with duration of a minute or greater.

The addition of the BES elements below 200 kV, beginning in the year 2015, significantly increased TADS inventory, especially for ac circuits. It should be noted that only sustained outages were collected by TADS for voltages less than 200 kV. This study is based on the 2015–2016 TADS data for sustained outages of the 100 kV and above ac circuits.

Table B.11 provides information on the number of sustained events in different ICC groups by year. Some ICC groups of sustained events do not have a population large enough to determine statistically significant year-over-year changes in TOS. For this analysis, the three smallest ICC groups (Fire; Environmental; and Vandalism, Terrorism, or Malicious Acts) were combined into a new group (Combined Smaller ICC groups Study 4–5). Vegetation is not one of Study 4's three smallest ICC groups, as it was in Study 1-3. For ac circuits below 200 kV, Vegetation initiates 7.5 percent of 100 kV+ ac circuits sustained events versus only 1.4 percent of sustained events of the 200 kV+ ac circuits.

In Table B.11, the reciprocal of the probability per hour of 0.653 estimates that in the defined BES system, a sustained ac circuit event started, on average, every one hour and 32 minutes.

Table B.11: Sustained Events 100 kV+ AC Circuits and Hourly Event Probability by ICC (2015–2016)

Initiating Cause Code	2015	2016	2015–2016	Sustained Event Initiation Probability/Hour
Weather (excluding lightning)	941	1,083	**2,024**	0.115
Failed AC Circuit Equipment	674	831	**1,505**	0.086
Unknown	781	712	**1,493**	0.085
Lightning	632	637	**1,269**	0.072
Failed AC Substation Equipment	522	545	**1,067**	0.061
Foreign Interference	440	539	**979**	0.056
Misoperation	330	435	**765**	0.044
Vegetation	301	317	**618**	0.035
Human Error (w/o Type 61 OR Type 62)	272	323	**595**	0.034
Other	177	157	**334**	0.019
Power System Condition	107	159	**266**	0.015
Contamination	76	178	**254**	0.014

[105] The TADS definition of Sustained Outage is different from the NERC *Glossary of Terms* used in *Reliability Standards* definition of Sustained Outage that is presently only used in FAC-003-1. The glossary defines a Sustained Outage as follows: "The de-energized-energized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure." The definition is inadequate for TADS reporting for two reasons. First, it has no time limit that would distinguish a sustained outage from a momentary outage. Second, for a circuit with no automatic reclosing, the outage would not be "counted" if the TO has a successful manual reclosing under the glossary definition.

Table B.11: Sustained Events 100 kV+ AC Circuits and Hourly Event Probability by ICC (2015–2016)				
Initiating Cause Code	**2015**	**2016**	**2015–2016**	**Sustained Event Initiation Probability/Hour**
Combined Smaller ICC Groups Study 4-5	139	142	**281**	0.016
Fire	113	120	**233**	0.013
Environmental	22	11	**33**	0.002
Vandalism, Terrorism, or Malicious Acts	4	11	**15**	0.001
With ICC Assigned	**5,392**	**6,058**	**11,450**	**0.653**
All Sustained Events	**5,392**	**6,058**	**11,450**	**0.653**

Out of the 11,450 sustained events in 2015–2016, a total of 7,445 (65 percent) events involve 100-199 kV ac circuits, 3,899 events (34.1 percent) involve 200 kV+ ac circuits, and only 106 events (0.9 percent) involve outages of ac circuits from both groups of voltage classes: 100-199 kV and 200 kV+.

From 2015 to 2016, the number of sustained ac circuit events increased by 12 percent. While the biggest increase, by 175 percent for ICC Vandalism, Terrorism, or Malicious Acts, can be considered as anecdotal (from four events in 2015 to 11 events in 2016), some larger groups also had significant increases: Weather, excluding lightning, (15 percent), Failed AC Circuit Equipment and Foreign Interference (23 percent each), Misoperation (32 percent), and Power System Condition (49 percent). On a positive side, the third biggest group, Unknown, had a decrease of nine percent.

Correlation Analysis and Distribution of TOS of Sustained AC Circuit Events by ICC

Figure B.8 shows the correlations between calculated TOS and the given ICC. A red bar corresponds to an ICC with statistically significant positive correlation with TOS, a green bar corresponds to an ICC with statistically significant negative correlation, and a blue bar indicates no significant correlation.

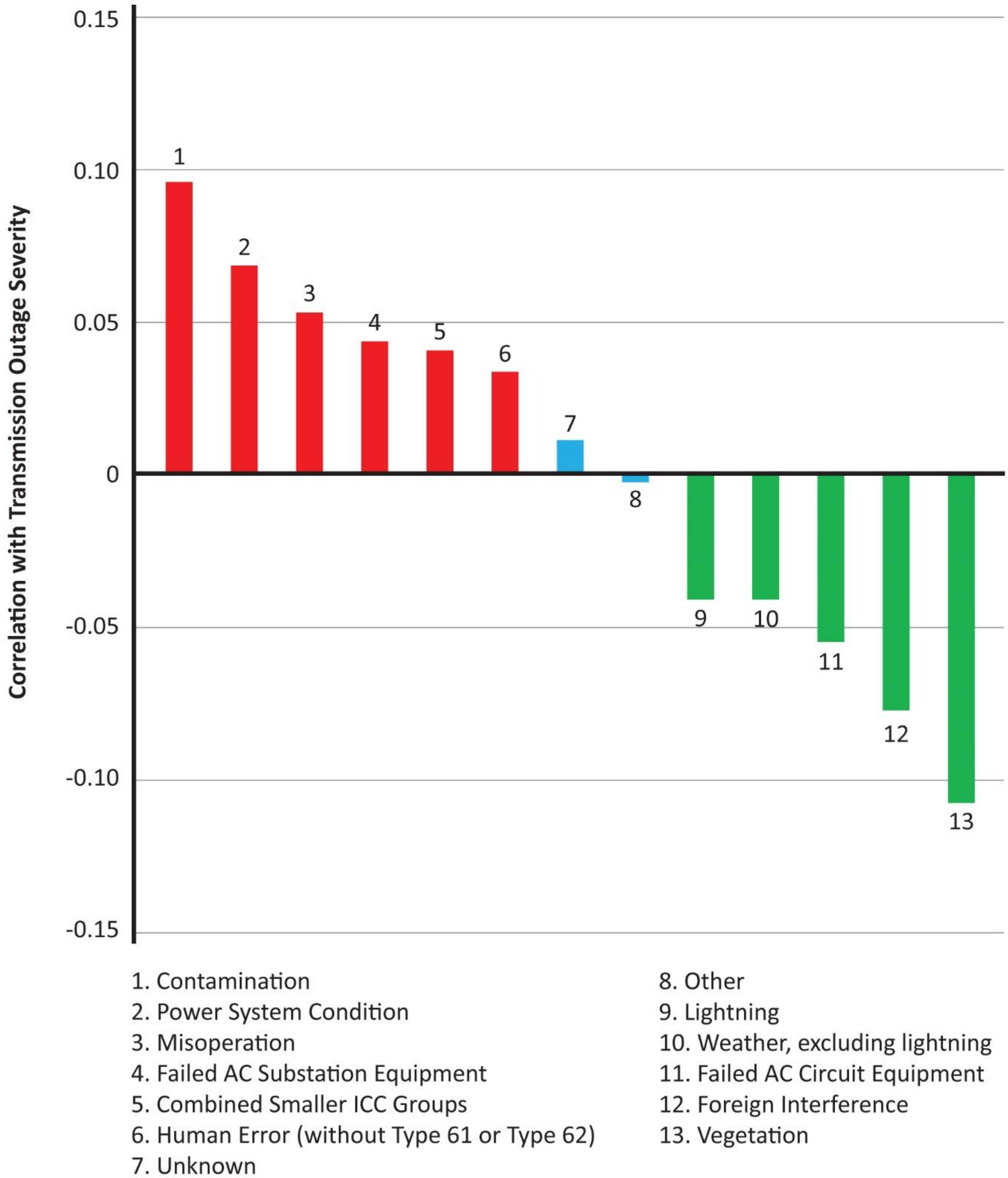


Figure B.8: Correlation between ICC and TOS of Sustained Events of 100 kV+ AC Circuits (2015–2016)

The results for most ICC groups are similar to the analysis of all 200 kV+ TADS events as illustrated by Figure B.3. However, the ICC with the highest positive correlation for sustained events, Contamination, does not have a significant correlation with TOS for all momentary and sustained events of the 200 kV+ ac circuits. Correlation analysis results are also different for ICCs Lightning and Unknown.

The distribution of TOS was studied separately for events with a given ICC and the complete dataset of sustained events for the two years combined. The TOS of the 2015–2016 TADS sustained events (100 kV+ ac circuits data set) has a sample mean of 0.051 and a sample standard deviation of 0.055. The sample statistics for TOS are listed in Table B.12 with the ICCs ordered from the largest average TOS to the smallest.

Statistical tests confirms that the groups of events initiated by Contamination, Power System Condition, Combined Smaller ICC groups, Misoperation, Human Error, Failed AC Substation Equipment Fire, and Unknown have statistically[106] greater expected outage severity than other events. This means that when an event initiated by one of these causes occurs, it has a greater impact and a higher risk to the transmission system on average. Moreover, the tests on homogeneity of variances highlights statistically greater variances (and the standard deviations) for the top six ICC groups as compared with other events. The greater variance is an additional risk factor since it implies more frequent occurrences of events with high TOS. Note that Combined Smaller ICC groups has a higher average TOS due to events initiated by Fire, which have the mean outage severity of 0.070.

Table B.12 also provides a column that lists ICCs with TOS statistically smaller than for a given ICC referenced by the table's initial column index. For example, Contamination initiates events with statistically larger TOS than any other ICC (indices 2–13).

Table B.12: Distribution of TOS of Sustained Events of 100 kV+ AC Circuits by ICC (2015–2016)

Index No.	ICC	Average TOS	Is Expected TOS Statistically Significantly Different than for Other Sustained Events?	ICC with Statistically Significantly Smaller Average TOS	Stand Deviation of TOS
1	Contamination	0.086	Larger	2,3,4,5,6,7,8,9,10,11,12,13	0.064
2	Power System Condition	0.075	Larger	3,4,5,6,7,8,9,10,11,12,13	0.081
3	Combined Smaller ICC Groups Study 4-5	0.066	Larger	7,8,9,10,11,12,13	0.063
4	Misoperation	0.062	Larger	7,8,9,10,11,12,13	0.070
5	Human Error (w/o Type 61 OR Type 62)	0.060	Larger	9,10,11,12,13	0.060
6	Failed AC Substation Equipment	0.059	Larger	9,10,11,12,13	0.069
7	Unknown	0.055	Larger	9,10,11,12,13	0.053
8	Other	0.054	No	10,11,12,13	0.063
	All Sustained events	**0.051**	**N/A**	**N/A**	**0.055**
	With ICC assigned	**0.051**	**N/A**	**N/A**	**0.055**
9	Lightning	0.050	No	10,11,12,13	0.054
10	Weather (excluding lightning)	0.046	Smaller	12,13	0.048
11	Failed AC Circuit Equipment	0.043	Smaller	12,13	0.046
12	Foreign Interference	0.036	Smaller	13	0.038
13	Vegetation	0.025	Smaller	none	0.027

[106] At significance level 0.05

Average TOS of Sustained Events by ICC: Annual Changes

Year-over-year changes in calculated TOS for 100 kV+ ac circuit events by ICC are reviewed next. **Figure B.9** shows changes in the average TOS for each ICC for the 2015–2016 dataset. The groups of ICC events are listed from left to right by descending average TOS for the two years combined. The largest average TOS over the data period was observed for sustained events initiated by Contamination.

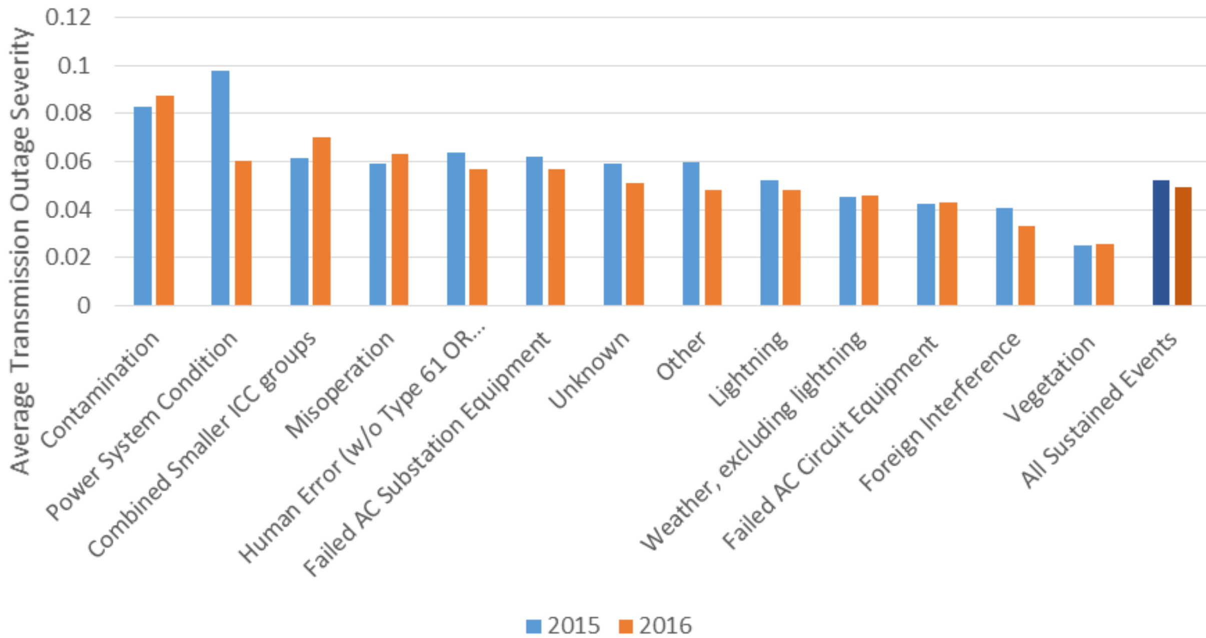


Figure B.9: Average of 100 kV+ AC Circuit Sustained Events by ICC and Year (2015–2016)

There were only three ICCs with statistically significant changes in the average TOS from 2015 to 2016: Power System Condition, Unknown, and Foreign Interference. All three were decreases. Overall, the average TOS of sustained events also statistically decreased from 2015 to 2016.

TOS Risk and Relative Risk of 100 kV+ AC Circuit Outage Events by ICC

The transmission risk and relative risk by ICC group were calculated, ranked, and are provided in Table B.13 with a breakdown of relative risk of sustained events by ICC.

Table B.13: Evaluation of 100 kV+ AC Circuit Sustained Event ICC Contribution to TOS (2015–2016)				
Group of Sustained Events	**Probability that an Event from a Group Starts During a Given Hour**	**Expected Impact (Expected TOS of an Event)**	**Risk Associated with a Group Per Hour**	**Relative Risk by Group**
All Sustained Events	0.653	0.051	0.033	**100%**
Sustained with ICC Assigned	0.653	0.051	0.033	**100%**
Weather (excluding lightning)	0.115	0.046	0.005	**16.0%**
Unknown	0.085	0.055	0.005	**14.3%**
Failed AC Circuit Equipment	0.086	0.043	0.004	**11.1%**
Lightning	0.072	0.050	0.004	**11.0%**
Failed AC Substation Equipment	0.061	0.059	0.004	**10.9%**
Misoperation	0.044	0.062	0.003	**8.1%**
Human Error (w/o Type 61 OR Type 62)	0.034	0.060	0.002	**6.2%**
Foreign Interference	0.056	0.036	0.002	**6.2%**
Contamination	0.014	0.086	0.001	**3.8%**
Power System Condition	0.015	0.075	0.001	**3.5%**
Combined Smaller ICC Groups Study 4–5	0.016	0.066	0.001	**3.2%**
Other	0.019	0.054	0.001	**3.1%**
Vegetation	0.035	0.025	0.001	**2.7%**

Analysis of TADS sustained events indicates that the ICC Weather (excluding lightning) has the greatest relative risk from 2015 to 2016 followed by Unknown. Sustained events with ICCs Failed AC Circuit Equipment and Failed AC Substation Equipment are the two largest contributors to TOS with the exception of Unknown and weather-related events. The two ICCs with the highest expected severity, Contamination and Power System Condition, rank low in Table B.13 because of relatively rare occurrences of sustained events with these ICCs. On the other hand, AC Circuit Equipment failures initiate sustained events with lower than average expected transmission severity, but the relative risk of this ICC ranks third due to the high frequency of these outages.

Figure B.10 shows year-over-year changes in the relative risk of TADS events by ICC. The groups of ICC events are listed from left to right by descending relative risk for the most recent two years combined. The top contributor to transmission risk—Weather (excluding lightning)—had an increase in relative risk in 2016 due to an increase in the number (and the frequency) of sustained events as reflected in Table B.11. In contrast, ICC Unknown had a decrease from 16.5 percent in 2015 to 12.2 percent in 2016; this was due to both a drop in the number of Unknown events and a statistically significant decrease in the average TOS of an event.

The relative risk of Misoperation increased from 7.0 percent in 2015 to 9.3 percent in 2016; this was mostly due to an increase in the number of outage events initiated by Misoperation. Also, there was an increase in the relative risk for the ICCs Failed AC Circuit Equipment, and decreases for Lightning and Failed AC Substation Equipment.

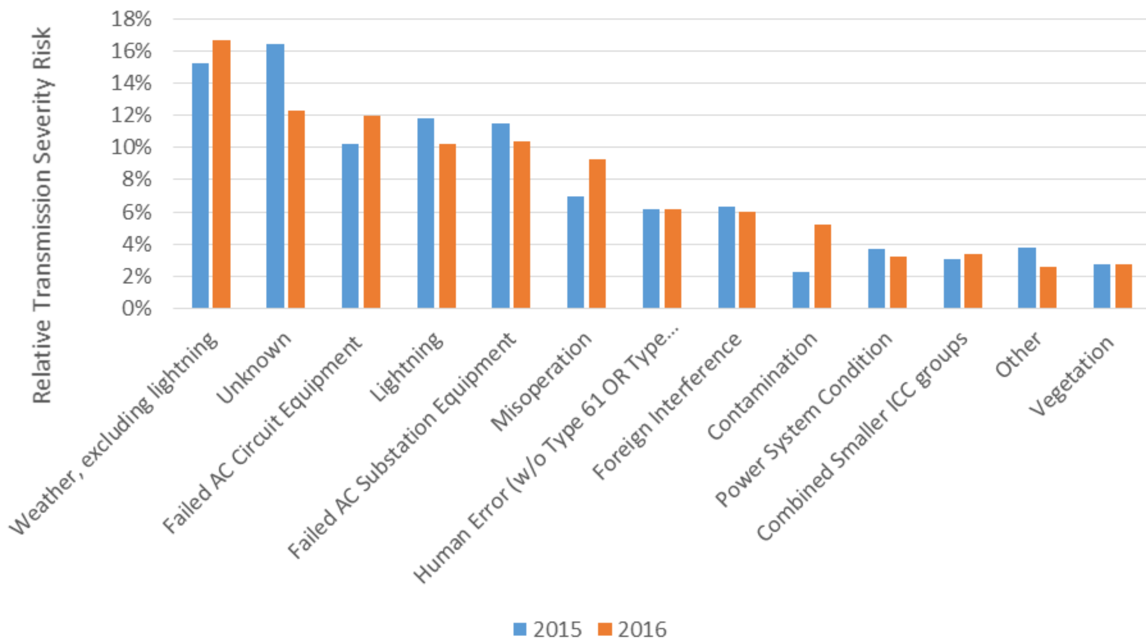


Figure B.10: Relative Risk 100 kV+ AC Circuit Sustained Events by ICC and Year (2015–2016)

Study 5: Sustained Events for 100 kV+ AC Circuits and Transformers (2016)

Sustained Events with Common ICC and Estimates of Event Probability

For the first time, NERC performs an ICC analysis for a combined set of ac circuit and transformer outage events. All 2016 sustained events involving these TADS elements of 100 kV and above are included in the study. The TOS of an event is calculated by applying Equation B.2 and Table B.1.

Table B.14 provides information on the number of sustained events in different ICC groups in 2016. Some ICC groups of sustained events do not have a population large enough for a reliable statistical comparison with other ICC groups. Similar to Study 4, the three smallest ICC groups (Fire; Environmental; and Vandalism, Terrorism, or Malicious Acts) were combined into a new group (Combined Smaller ICC groups Study 4–5). In Table B.14, the reciprocal of the probability per hour of 0.720 estimates that in the defined BES system, a sustained ac circuit or transformer event started, on average, every hour and 23 minutes.

Initiating Cause Code	2016	Sustained Event Initiation Probability/Hour
Weather (excluding lightning)	**1090**	0.124
Failed AC Circuit Equipment	**841**	0.096
Unknown	**741**	0.084
Lightning	**647**	0.074
Failed AC Substation Equipment	**618**	0.070
Foreign Interference	**555**	0.063
Misoperation	**480**	0.055
Human Error (w/o Type 61 or Type 62)	**343**	0.039
Vegetation	**318**	0.036
Contamination	**178**	0.020
Other	**164**	0.019
Power System Condition	**159**	0.018
Combined Smaller ICC Groups Study 4-5	**151**	0.017
Fire	*128*	0.015
Vandalism, Terrorism, or Malicious Acts	*13*	0.001
Environmental	*10*	0.001
Sustained with ICC Assigned	**6285**	**0.716**
Sustained Events	**6332**	**0.721**

Table B.14: Sustained Events 100 kV+ AC Circuits and Transformers and Hourly Event Probability by ICC (2016)

Comparison of the information in Table B.14 and the 2016 column in Table B.11, which lists the counts of sustained events for 100 kV+ ac circuits, leads to several conclusions. First, the majority of sustained events in Study 5 involves ac circuits (6,058 out of 6,332 events). Second, the ICC ranking with respect to the number of events did not change after addition of the transformer events. These results are not surprising because TADS ac circuit inventory and outage counts are much larger than those for transformers.

Table B.14: Sustained Events 100 kV+ AC Circuits and Transformers and Hourly Event Probability by ICC (2016)		
Initiating Cause Code	**2016**	**Sustained Event Initiation Probability/Hour**
Weather (excluding lightning)	**1,090**	0.124
Failed AC Circuit Equipment	**841**	0.096
Unknown	**741**	0.084
Lightning	**647**	0.074
Failed AC Substation Equipment	**618**	0.070
Foreign Interference	**555**	0.063
Misoperation	**480**	0.055
Human Error (w/o Type 61 or Type 62)	**343**	0.039
Vegetation	**318**	0.036
Contamination	**178**	0.020
Other	**164**	0.019
Power System Condition	**159**	0.018
Combined Smaller ICC groups Study 4–5	**151**	0.017
Fire	*128*	0.015
Vandalism, Terrorism, or Malicious Acts	*13*	0.001
Environmental	*10*	0.001
Sustained with ICC Assigned	**6,285**	**0.716**
Sustained Events	**6,332**	**0.721**

Correlation Analysis and Distribution of TOS of Sustained AC Circuit and Transformer Events by ICC

Figure B.11 shows the correlations between calculated TOS and the given ICC. A red bar corresponds to an ICC with statistically significant positive correlation with TOS, a green bar corresponds to an ICC with statistically significant negative correlation, and a blue bar indicates no significant correlation.

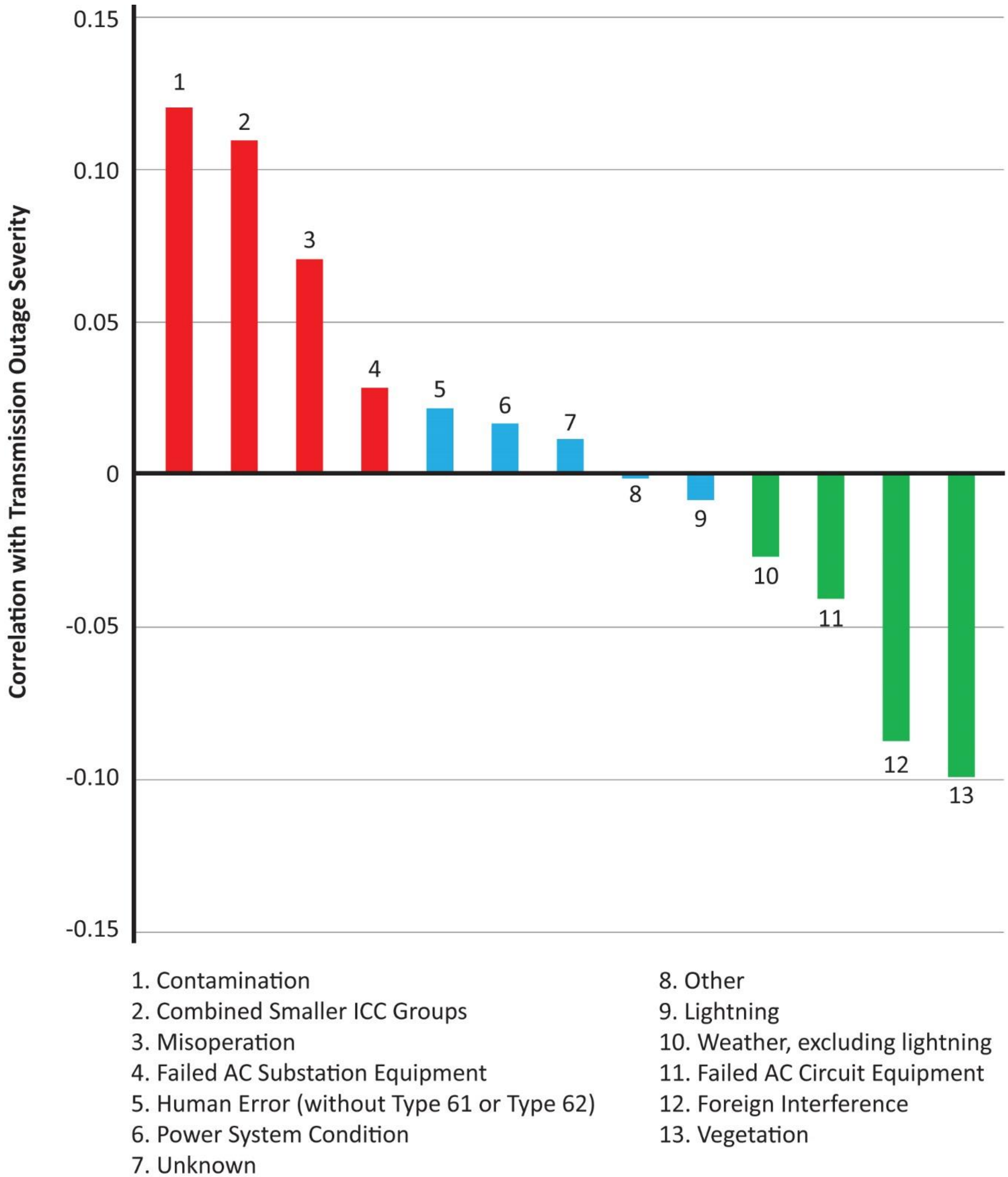


Figure B.11: Correlation between ICC and TOS of Sustained Events of 100 kV+ AC Circuits and Transformers (2016)

The ICC Power System Condition for the mixed inventory does not have a significant correlation with the transmission severity, unlike results for ac circuit events only. This is shown in Figure B.3 and Figure B.8.

The distribution of TOS was studied separately for events with a given ICC and the complete dataset of sustained events. The TOS of the 2016 TADS sustained events 100 kV+ ac circuit and transformer data set has a sample mean of 0.042 and a sample standard deviation of 0.047. The sample statistics for TOS are listed in Table B.15 with the ICCs ordered from the largest average TOS to the smallest. The addition of transformers to Study 4 leads to an overall decrease in the TOS of the events, reflecting differences in equivalent MVA's for ac circuits and transformers when compared to Table B.1.

Table B.15: Distribution of TOS of Sustained Events of 100 kV+ AC Circuits and Transformers by ICC (2016)					
Index No.	**Initiating Cause Code (ICC)**	**Average TOS**	**Is Expected TOS Statistically Significantly Different than for Other Sustained Events?**	**ICC with Statistically Significantly Smaller Average TOS**	**Stand Deviation of TOS**
1	Contamination	0.074	Larger	3,4,5,6,7,8,9,10,11,12,13	0.054
2	Combined Smaller ICC Groups	0.073	Larger	3,4,5,6,7,8,9,10,11,12,13	0.084
3	Misoperation	0.053	Larger	5,6,7,8,9,10,11,12,13	0.056
4	Power System Condition	0.046	No	11,12,13	0.048
5	Human Error (w/o Type 61 or Type 62)	0.045	No	10,11,12,13	0.042
6	Failed AC Substation Equipment	0.045	No	9,10,11,12,13	0.053
7	Unknown	0.043	No	11,12,13	0.042
	All Sustained Events	**0.042**	**N/A**	**N/A**	**0.047**
	Sustained with ICC Assigned	**0.041**	**N/A**	**N/A**	**0.046**
8	Other	0.041	No	12,13	0.037
9	Lightning	0.040	No	12,13	0.044
10	Weather (excluding lightning)	0.039	Smaller	12,13	0.042
11	Failed AC Circuit Equipment	0.037	Smaller	12,13	0.042
12	Foreign Interference	0.028	Smaller	13	0.027
13	Vegetation	0.021	Smaller	none	0.025

Statistical tests found that the groups of events initiated by Contamination, Combined Smaller ICC groups, and Misoperation have statistically[107] greater expected outage severity than other events. This means that when an event initiated by one of these causes occurs, it has a greater impact and a higher risk to the transmission system on average. Moreover, the tests on the homogeneity of variances highlights statistically greater variances (and the standard deviations) for the top six ICC groups as compared with other events. The greater variance is an additional risk factor since it implies more frequent occurrences of events with high TOS. The Combined Smaller ICC groups Studies 4–5 have a higher average TOS due to events initiated by Fire and Environmental, which both have the mean outage severity of 0.077.

Table B.15 also provides a column that lists ICCs with TOS statistically smaller than for a given ICC referenced by the table's initial column index. For example, Contamination initiates events with statistically larger TOS than any

[107] At significance level 0.05

other ICC except Combined Smaller ICC groups (indices 3-13 in Table B.15). Therefore, an expected impact of events initiated by Contamination and Combined Smaller ICC groups is statistically similar.

TOS Risk and Relative Risk of 100 kV+ AC Circuit and Transformer Events by ICC

The transmission risk and relative risk by ICC group were calculated, ranked, and are provided in Table B.16 with a breakdown of relative risk of sustained events by ICC.

Table B.16: Evaluation of 100 kV+ AC Circuit and Transformer Sustained Event ICC Contribution to TOS (2016)

Group of Sustained Events	Probability that an Event from a Group Starts During a Given Hour	Expected Impact (Expected TOS of an Event)	Risk Associated with a Group Per Hour	Relative Risk by Group
All Sustained Events	0.721	0.042	0.030	**100%**
Sustained with ICC Assigned	0.721	0.041	0.030	**97.8%**
Weather (excluding lightning)	0.039	0.124	0.005	**15.8%**
Unknown	0.043	0.084	0.004	**11.9%**
Failed AC Circuit Equipment	0.037	0.096	0.003	**11.6%**
Failed AC Substation Equipment	0.045	0.070	0.003	**10.5%**
Lightning	0.040	0.074	0.003	**9.8%**
Misoperation	0.053	0.055	0.003	**9.5%**
Foreign Interference	0.028	0.063	0.002	**5.9%**
Human Error (w/o Type 61 or Type 62)	0.045	0.039	0.002	**5.9%**
Contamination	0.074	0.020	0.001	**4.9%**
Combined Smaller ICC Groups	0.073	0.017	0.001	**4.2%**
Power System Condition	0.046	0.018	0.001	**2.8%**
Vegetation	0.021	0.036	0.001	**2.6%**
Other	0.041	0.019	0.001	**2.5%**

Analysis of TADS sustained events indicate that the ICC Weather (excluding lightning) had the greatest relative risk in 2016, following by Unknown. Sustained events with ICCs Failed AC Circuit Equipment and Failed AC Substation Equipment are the two largest contributors to TOS with the exception of Unknown and weather-related events. The two ICCs with the highest expected severity, Contamination and Combined Smaller ICC groups, rank low in Table B.16 because of relatively rare occurrences of sustained events with these ICCs. However, AC Circuit Equipment failures initiate sustained events with lower than average expected transmission severity, but due to high frequency of these outages, the relative risk of this ICC ranks third.

Overall, the ICC rankings by contribution to the total transmission severity shown in Table B.13 (sustained ac circuit events), and Table B.15 (sustained events of ac circuits and transformers) are very similar. As noted above, the addition of TADS transformer outage events and inventory data to Study 4 does not change most results and conclusions of the analysis.

Study 6: Sustained Cause Code Study for Sustained Outages of 100 kV+ AC Circuits (2015–2016)

Beside an ICC, a sustained cause code (SCC) is assigned to a sustained outage. The SCC describes the cause that contributed to the longest duration of the outage. The list of TADS SCCs is the same as the list of ICCs as shown in Table B.4. A method of assigning a single SCC to a TADS event with multiple outages having different SCCs has not yet been developed; therefore, it is not yet possible to analyze SCCs by applying the same methodology as described in Studies 1–5 for ICCs.

In this study, the 2015–2016 sustained outages of the 100 kV+ ac circuits with a TOS calculated by Equation B.1 are investigated by SCC. TADS outages, unlike TADS events, can be dependent; thus, they do not represent a statistical sample with independent observations. Therefore, the risk analysis for outages is limited to the TOS calculation, numerical comparison of the TOS of SCC groups, and their ranking. However, there is another important variable reported for sustained outages—the outage duration. Provided In **Table B.17** are some statistics on the outage duration by SCC and suggested a way to incorporate duration into analysis of the relative risk by SCC.

Table B.17 lists the number of outages, the average, the median, and the maximum outage duration by SCC and overall for the 2015–2016 sustained outages of the 100 kV+ ac circuits. SCCs are listed in decreasing order by number of outages.

Table B.17: TADS Sustained Outages 100 kV+ AC Circuits (2015–2016)

Sustained Cause Code	Number of Outages	Average Outage Duration (Hours)	Median Outage Duration (Hours)	Maximum Duration (Days)
Failed AC Circuit Equipment	2,441	54.0	12.23	366.0
Failed AC Substation Equipment	1,611	39.4	3.05	264.4
Weather (excluding lightning)	1,435	16.8	1.32	107.8
Unknown	1,377	7.4	0.17	83.4
Other	1,314	8.4	0.27	95.1
Misoperation	1,146	8.7	0.85	34.5
Foreign Interference	959	9.7	2.13	25.6
Lightning	815	3.7	0.12	37.6
Vegetation	732	32.7	0.25	57.9
Human Error	732	4.6	10.96	40.1
Power System Condition	581	21.6	0.48	111.9
Contamination	223	7.8	0.33	5.6
Fire	186	34.9	4.25	52.9
Environmental	53	39.6	8.77	24.2
Vandalism, Terrorism, or Malicious Acts	15	11.1	7.18	1.0
All Sustained Outages	**13,620**	**23.0**	**1.90**	**366.0**

The SCC order differs from that seen for ICC groups in studies 1, 2, and 4 (Tables B.4, B.8, B.11 and B.14). Outages with SCC Failed AC Circuit Equipment not only comprise the largest group, but they have also, on average, the longest duration. Another observation is that SCC Unknown, being the fourth biggest group, has the third shortest average outage duration (7.4 hours versus 23.0 hours for all sustained events).

The TOS of each outage is calculated by Equation B.1, then the total TOS of each SCC group is calculated, and the relative risk of a SCC is determined based on contribution of the group to the total TOS of all 2015–2016 sustained outages. The analysis is repeated for the TOS weighted with an outage duration with the purpose to take into account the outage duration and incorporate it as a factor that impacts transmission outage risk. The results of these two analyses of the relative SCC risk are compared to illustrate how outage duration affects the SCC ranking.

Since there are outages with very large durations (up to 366 days), two types of sensitivity analysis are performed to the evaluation of transmission severity weighted with outage duration: First, the SCC analysis is repeated for all outages not longer than one month (with the 78 outages or about 0.6 percent of the total dataset removed); second, the analysis is rerun with the top percent of longest outages removed (132 outages longer than 14.4 days removed).

Figure B.12 summarizes results of the four analyses of the relative transmission outage risk by SCC. The SCCs with relative transmission outage risks rounded to zero percent. Environmental and Vandalism, Terrorism, and Malicious Acts, the two SCC groups with less than 1 percent of the relative transmission outage risk each, are not shown.

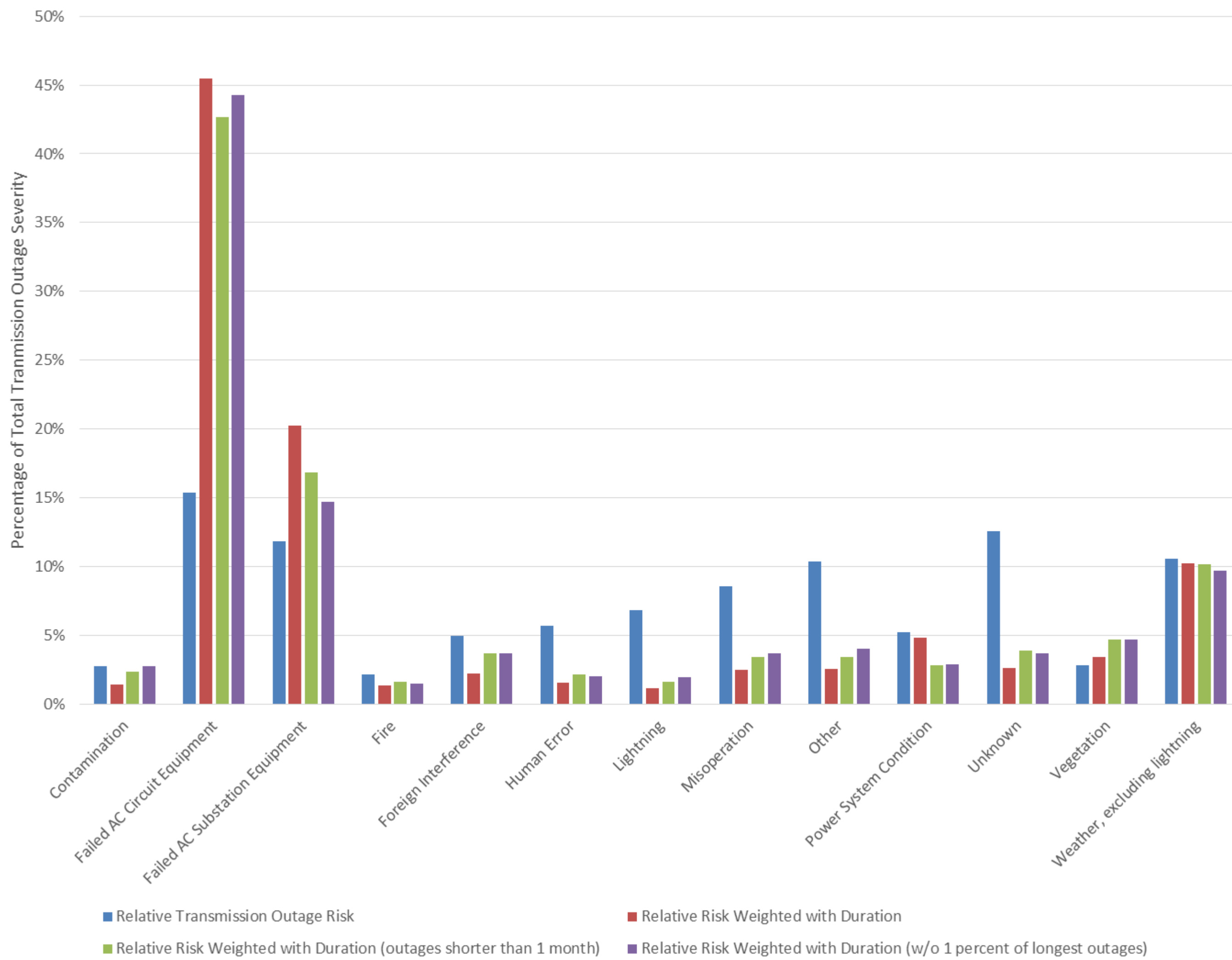


Figure B.12: Relative TOS Risk by SCC for Sustained Outages of the 100 kV+ AC Circuits (2015—2016)

Figure B.12 shows the SCC relative transmission outage risk and the SCC relative transmission outage risk weighted with duration. The largest differences are observed for the SCCs with "nontypical" average outage durations (i.e., the average outage duration significantly different from the average duration of 23 hours).

Events with SCC Failed AC Circuit Equipment have the highest average duration. The relative transmission outage risk of this SCC increases from 15 percent to 45 percent. For SCCs with shorter average durations such as Unknown, Other, Lightning, Misoperation, Human Error, and Foreign Interference, the relative transmission outage risks are noticeably lower when weighted with outage duration (e.g., for SCC Unknown from 13 percent to three percent of the total transmission severity and for SCC Misoperation from nine percent to two percent).

Comparison of the three right-hand side bars for each SCC allows us to draw some observations on sensitivity analyses and evaluate effect of the longest outages on the SCC relative risk. Overall, an SCC relative risk does not change much among these three types; this fact confirms that the SCC relative transmission outage risk weighted with duration calculations are robust with respect to duration outliers.

Table B.18 shows the SCC rankings by relative transmission outage risk (unweighted and weighted with outage duration).

Table B.18: SCC Ranking for TADS Sustained Outages 100 kV+ AC Circuits (2015–2016)		
Sustained Cause Code	**By Relative Transmission Outage Risk**	**By Relative Transmission Outage Risk Weighted with Outage Duration**
Contamination	12	11
Environmental	14	14
Failed AC Circuit Equipment	**1**	**1**
Failed AC Substation Equipment	3	2
Fire	13	12
Foreign Interference	10	9
Human Error	8	10
Lightning	7	13
Misoperation	6	8
Other	5	7
Power System Condition	9	4
Unknown	2	6
Vandalism, Terrorism, or Malicious Acts	15	15
Vegetation	11	5
Weather (excluding lightning)	4	3

For several SCCs, there are significant differences between their respective ranks. As the result of Study 6, both rankings are derived and presented without making a decision about superiority of either method of the relative transmission outage risk evaluation. Each method has its advantages and disadvantages: the transmission outage risk that is based on TOS calculations without duration is simpler and allows for the analysis of all outages and events (which is more important) of both momentary and sustained. The transmission outage risk, based on the TOS weighted with outage duration discards momentary outages from the analysis, and while it does take into account differences in sustained outage duration, more analysis and the industry expert discussions are needed to decide whether the weighing is fair. For example, as a result of this weighting, an one-hour ac circuit outage from the 300–399 kV voltage class contributes to the total weighted transmission severity equally with an outage of the 100–199 kV ac circuit with duration of six hours and 30 minutes; with an outage of the 200-299 kV ac circuit with duration of one hours and 51 minutes; with an outage of the 400-599 kV ac circuit with duration of 39 minutes; and with an outage of the 600–799 kV ac circuit with duration of 26 minutes).

Summary of TADS Data Analysis

The statistical analysis of the 2012–2016 TADS data on the TOS, initiating and sustained causes of TADS outage events, yields the following observations:

- **Weather (excluding lightning)** was a top contributor to TOS of the 2016 sustained events for ac circuits and transformers (Study 5). From 2015 to 2016, the number of the weather-initiated momentary and sustained events of 200 kV+ ac circuits increased by 28 percent (Study 1) and the number of weather-initiated sustained events of 100 kV+ ac circuits increased by 15 percent (Study 4) while the respective TADS inventory increases were below 0.6 percent. Additionally, Weather (excluding lightning) ranks 3rd among sustained causes of ac circuit outages (Study 6).

- **Unknown** initiated fewer TADS events in 2016 compared with 2015: the number of Unknown momentary and sustained events of 200 kV+ ac circuits and the number of Unknown sustained events of 100 kV+ ac circuits both reduced (Studies 1 and 4, respectively). Moreover, from 2015 to 2016, the average transmission severity of sustained events with ICC Unknown statistically significantly reduced while the relative transmission outage risk of this ICC decreased from 16.5 percent to 12.2 percent.
- The number of combined momentary and sustained events of 200 kV+ ac circuits and sustained events of 100 kV+ circuits initiated by **Misoperation** increased in 2016 (Study 1 and Study 4, respectively). Relative risk of the ICC Misoperation also increased for these two datasets (studies 1 and 4). For 2012–2016 events with multiple outages (CDM events), Misoperation is a biggest group and the top contributor to the TOS (Study 2).
- The number of TADS events initiated by **Failed AC Circuit Equipment** increased significantly in 2016: by 43 percent for combined momentary and sustained events of 200 kV+ ac circuits (Study 1) and by 23 percent for sustained events of 100 kV+ ac circuits (Study 4). Events with this ICC on average have a smaller TOS, but because of their high frequency of occurrence they rank as the 3rd contributor of the TOS of sustained events of ac circuits (Study 4). Sustained outages with sustained cause code Failed AC Circuit Equipment are the largest group of ac circuit sustained outages; moreover, they have, on average, the longest duration among all sustained outages (Study 6).
- The number of combined momentary and sustained events of 200 kV+ ac circuits and the number of sustained events of 100 kV+ ac circuits both increased from 2015 to 2016, but the average TOS of an event statistically significantly decreased for both datasets (Studies 1 and 4).
- The addition of TADS transformer outages and inventory to the data for sustained events of 100 kV+ ac circuits did not significantly increase the number of events and did not lead to big changes in ranking of ICCs by size and by relative risk and other results of the analysis (Study 4 and Study 5).

Appendix C: Analysis of Generation Data

GADS, beginning in 2013, collects for conventional generating units that are 20 MW. In addition, smaller units and other units outside of NERC's jurisdiction report into GADS on a voluntary basis. The analysis for this report includes only active units with a mandatory reporting obligation.[108] Data used in the analysis includes information reported into GADS through the end of 2016.

GADS does not include wind, solar, other renewable technology generating assets, distributed energy resources, or other small energy sources. Wind performance data reporting requirements have been developed, and a phased-in reporting process begins in 2017 and continues through 2020. Reporting data requirements for solar have been initiated with a target goal of data submittal by 2021.

GADS collects and stores unit operating information. By pooling individual unit information, overall generating unit availability performance and metrics are calculated. The information supports equipment reliability, availability analyses, and risk-informed decision making to industry. Reports and information resulting from the data collected through GADS are used by industry for benchmarking and analyzing electric power plants. **Table C.1** shows the number of units and average age characteristics of the population in GADS and select unit types for each year.

Table C.1: Key Characteristics of GADS

Metric/year	2012	2013	2014	2015	2016
Number of Reporting Units	4,486	6,121	6,125	6,083	5,961
Average Age of the Fleet (years)	34	36	36	35	35
Average Age of Coal Units (years)	47	46	46	45	43
Average Age of Gas Units (years)	23	24	24	23	23
Average Age of Nuclear Units (years)	38	38	38	38	37

The age of the generating fleet is considered to be a particularly relevant statistic derived from GADS because an aging fleet could potentially see increasing outages. However, with proper maintenance and equipment replacement, older units may perform comparably to newer units. In addition, the weighted equivalent forced outage rate, reported later in this section, shows declining rates of forced outages. **Table C.1** also provides some validation of the retirements of older coal units, which is reflected in the decline in average age of coal units between 2015 and 2016. Future reports will continue to monitor this to help illustrate how the fleet is changing.

Figure C.1 uses GADS data to plot fleet capacity by age and fuel type. **Figure C.1** shows two characteristics of the fleet reported to GADS: 1) an age bubble exists around 37–46 years, by a population consisting of coal and some gas units; and 2) a significant age bubble around 12–20 years is comprised almost exclusively of gas units. The data shows a clear shift toward gas-fired unit additions, and the overall age of the fleet across North America is almost 10 years younger than the age of the coal-fired base-load plants that have been the backbone of power supply for many years. This trend is projected to continue given current forecasts around price and availability of natural gas as a power generation fuel as well as regulatory impetus.

[108] In 2015, fewer than 100 MW of units had a voluntary reporting status in GADS.

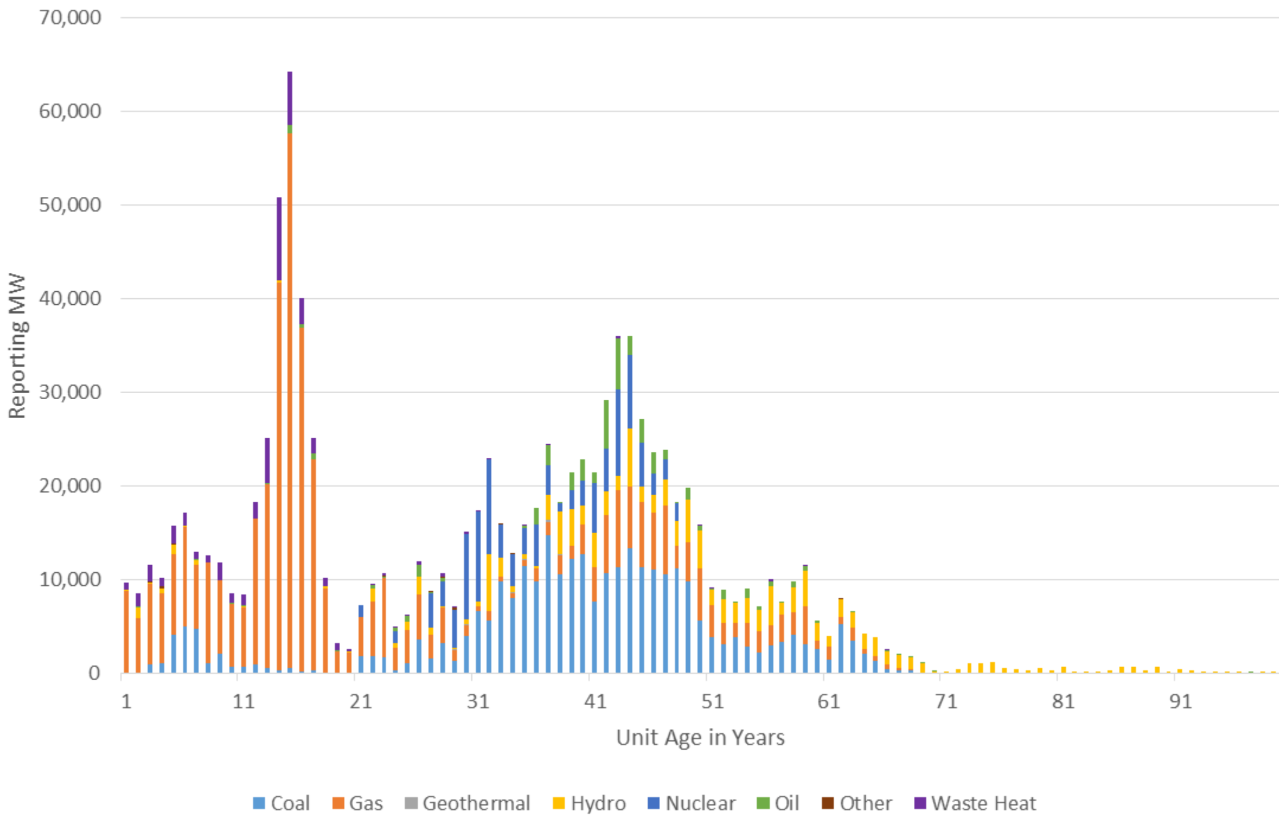


Figure C.1: Fleet Capacity by Age and Fuel Type as of January 1, 2017

Generator Fleet Reliability

GADS contains information that can be used to compute several reliability measures such as WEFOR. WEFOR is a metric measuring the probability that a unit will not be available to deliver its full capacity at any given time, taking into consideration forced outages and derates.

Figure C.2 presents the monthly megawatt-weighted EFOR[109] across the NERC footprint for the five-year period of 2012–2016.[110] The horizontal steps show the annual EFOR compared to the monthly EFOR; the solid horizontal bar in **Figure C.2** show the mean outage rate over each year. The mean outage rate over the analysis period is 7.1 percent. The EFOR has been fairly consistent with a near-exact standard distribution.

[109] The use of the weighted EFOR (weighted by the Net Maximum Capacity- NMC as reported in GADS Performance data) allows for comparison of units that vary by size.

[110] The reporting year covers January 1 through December 31.

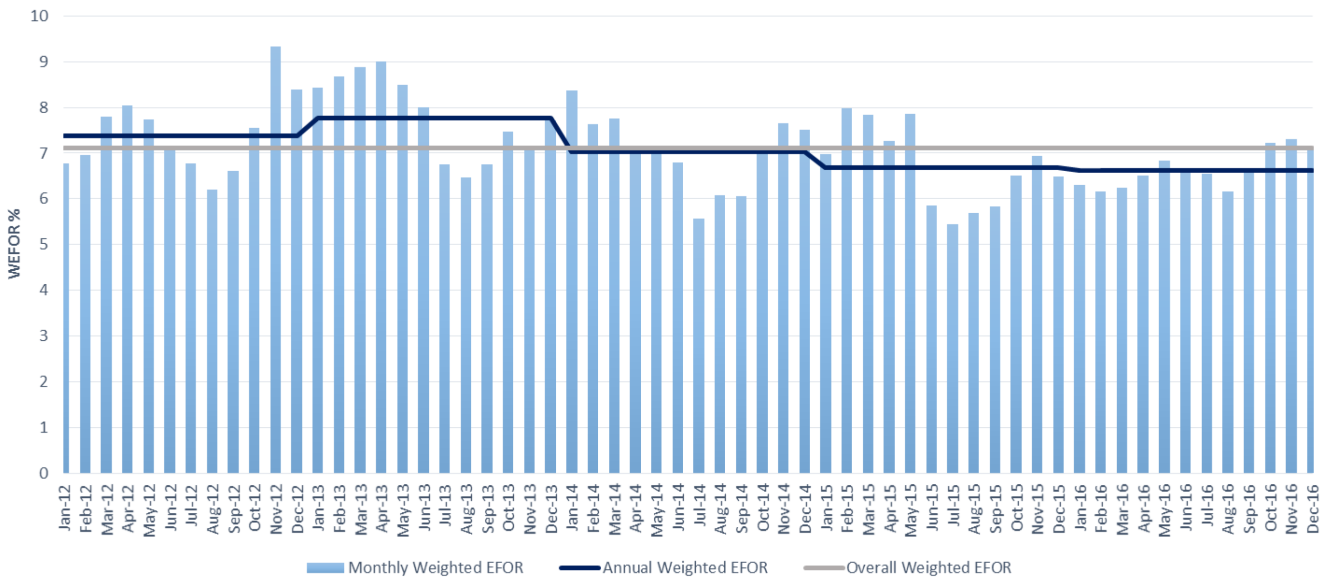


Figure C.2: Monthly MW Capacity-Weighted EFOR 2012–2016

Forced Outage Causes

To better understand the causes of forced outages of generators, the annual and top 10 forced outage causes for the summer and winter seasons[111] were analyzed for the period of 2012–2016. This analysis is focused on forced outage causes measured in terms of net MWh of potential production lost, so both the amount of capacity affected and the duration of the outages are captured.

The levels of forced outages reported into the GADS database are presented in **Figure C.3** and **Table C.2**, providing detail on the net MWh of potential production lost due to forced outages for the period 2012–2016 by calendar year.

[111] Winter includes the months of January, February and December. When analysis is performed on a calendar year basis, as for this report, these three months are included from the same calendar year. Summer includes May through September; all other months are categorized as Spring/Fall.

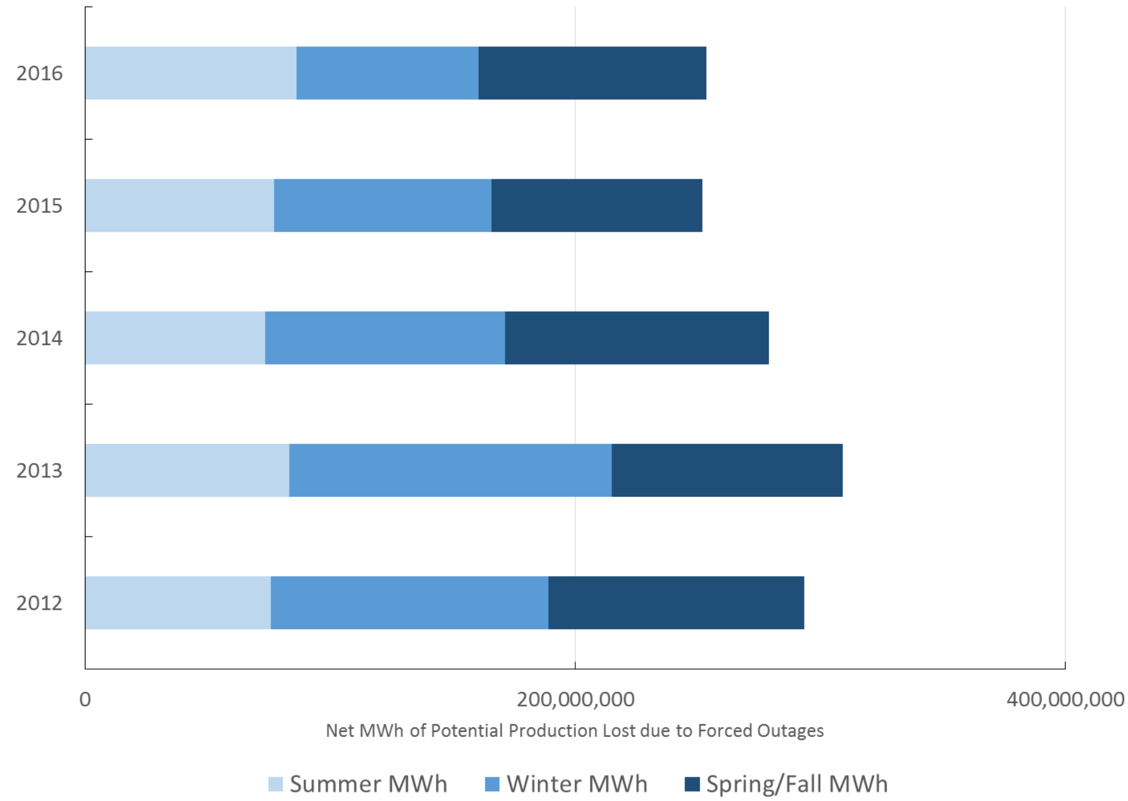


Figure C.3: Total Net MWh of Potential Production Lost Due to Forced Outages 2012–2016

Table C.2: Total Net MWh of Potential Production Lost Due to Forced Outages, by Calendar Year 2012–2016				
NERC	Total Annual MWh	Summer MWh	Winter MWh	Spring/Fall MWh
2012	293,475,653	75,914,722	112,989,119	104,571,812
2013	309,011,065	83,422,362	131,422,688	94,166,015
2014	278,987,876	73,610,732	97,782,322	107,594,822
2015	251,795,168	76,955,351	88,651,639	86,188,178
2016	253,530,864	86,112,430	74,256,269	93,162,171

Based on the five years of available data since GADS reporting became mandatory, the following observations can be made:

- Severe storms in the last quarter of 2012, such as Hurricane Sandy, resulted in an increase in the net MWh of potential production lost due to forced outages reported for Winter 2013.[112]
- The shoulder months of Spring/Fall in 2014 and 2016 have higher forced outage net MWh than the corresponding summer or winter periods.

Further analysis into the causes of forced outages considered the impact of weather. The percentage of net MWh of potential production lost due to weather-related forced outage cause codes reported each year ranges from two percent to four percent annually. This indicates that while weather does cause major headlines and affects

[112] For this analysis, the season of a forced outage is associated with the season in which the start date of the event was reported in that year; when an event continues into the next year, a new event record is created in January. This results in the event being categorized as occurring in the winter for the continuation event.

the days included in the SRI, the overall effect of weather on the fleet is minimal. The real impacts of weather-related events are localized impacts and of relatively short duration.

To gain additional insight into the drivers for the reported net MWh of potential production lost due to forced outages, the top 10 forced outage causes were examined to determine their impact on the annual total of net MWh of potential production lost. The number of events reported in the top 10 forced outage causes represent between seven percent and 12 percent of all forced outage events reported annually while contributing an average of 28 percent to the annual total megawatt hours lost. **Table C.3** shows the contribution of the top 10 forced outage causes to net MWh of potential production lost on a NERC-wide basis over the period 2012–2016.

Table C.3: Percentage of Top 10 Forced Outage Cause MWh by Year to Annual Net MWh of Potential Production Lost Due to Forced Outages by Calendar Year 2012-2016

NERC	Total Annual MWh	Summer MWh	Winter MWh	Spring/Fall MWh
2012	29%	5%	13%	11%
2013	29%	7%	13%	9%
2014	28%	6%	11%	11%
2015	24%	7%	9%	8%
2016	28%	8%	9%	11%

The top 10 causes vary annually, and the contribution from each of the top 10 causes to the total megawatt hours lost varies as well. **Table C.4** lists the top 10 forced outage causes on an annual basis in order of the most impactful cause to the least, based on annual net MWh of potential production lost due to forced outages.

Table C.4: Top 10 Cause Codes as Percentage of Annual Net MWh of Potential Production Lost Due to Forced Outages

Rank	2012	2013	2014	2015	2016
1	Waterwall (furnace wall) 5.2%	Waterwall (furnace wall) 5.9%	Waterwall (furnace wall) 7.7%	Waterwall (furnace wall) 6.4%	Waterwall (furnace wall) 6.9%
2	Rotor – General 3.3%	Main Transformer 4.1%	Lack of Fuel (Interruptible Supply of Fuel) 3.7%	Main Transformer 5.7%	Main Transformer 4.7%
3	Steam Generator Tube Leaks 3.2%	Rotor – General 3.2%	Main Transformer 3.2%	First Reheater 2.3%	Stator Windings, Bushings, and Terminals 2.8%
4	Main Transformer 2.8%	Second Superheater 2.9%	Second Superheater 2.7%	Lack of Fuel (interruptible supply of fuel) 1.8%	Other Exciter Problems 2.5%
5	Transmission System Problems other than Catastrophes 2.8%	Operator Error 2.8%	First Reheater 2.5%	Second Superheater 1.5%	Flood 2.1%
6	Steam Generator Tube Inspections 2.8%	Stator Windings, Bushings, and Terminals 2.3%	Emergency Generator Trip Devices 1.8%	Boiler – Miscellaneous 1.5%	First Reheater 1.9%

Table C.4: Top 10 Cause Codes as Percentage of Annual Net MWh of Potential Production Lost Due to Forced Outages					
Rank	**2012**	**2013**	**2014**	**2015**	**2016**
7	Containment Structure 2.6%	Stator – General 2.1%	AC Conductors and Buses 1.7%	Generator Vibration 1.5%	Second Superheater 1.7%
8	Stator Windings, Bushings, and Terminals 2.1%	Hurricane 2.0%	Other Low Pressure Turbine Problems 1.7%	First Superheater 1.5%	Other Miscellaneous Generator Problems 1.7%
9	Second Superheater 2.1%	Rotor Windings 2.0%	First Superheater 1.6%	Other Boiler Tube Leaks 1.5%	Residual Heat Removal/Decay Heat Removal System 1.5%
10	Generator Output Breaker 1.8%	First Reheater 1.7%	Boiler – Miscellaneous 1.5%	Other Exciter Problems 1.4%	Other Boiler Tube Leaks 1.5%

Several outage causes appear in the top 10 more often than others: Weather-related outages in 2012 due to Hurricane Sandy resulted in flooding which impacted several units that continued to report forced outages into 2013 and 2014. Lack of Fuel occurs within the top causes in 2014 and 2015. **Table C.5** lists the recurring cause codes and number of years that the cause code appears in the top 10.

Table C.5: Recurring Top-10 Cause Codes		
Code	**Description**	**Number of Years in Top 10 Causes**
1050	Second Superheater	5
1000	Waterwall (furnace wall)	5
3620	Main Transformer	5
1060	First Reheater	4
4520	Stator Windings, Bushings, and Terminals	3
9131	Lack of Fuel (interruptible supply of fuel)	2
1090	Other Boiler Tube Leaks	2
1999	Boiler – Miscellaneous	2
1040	First Superheater	2
4511	Rotor – General	2
4609	Other Excited Problems	2

The First Superheater (cause code 1040), Second Superheater (1050), Waterwall (1000), and First Reheater (1060) are all related to tube leaks in the respective systems. Given the amount of steam generating units that make up the fleet, the magnitude of these outages would not be unusual. These are not uncommon failures that occur in normal operation.

Both the Main Transformer (3620) and Stator Windings (4520) are high on the list. These items are the result of a very low likelihood event occurring that has a high impact. Most plants do not have spares available for these assets because the likelihood of failure is very low. However, if an event does occur, it can take several months to remedy, causing the event to show very high on this cause code list.

Recommendations:

- NERC, through the GADSWG, should consider requiring design data from the units to help improve analytics on the generating fleet and its possible impacts to BES reliability.
- NERC, through the GADSWG, should continue to investigate seasonal performance trends for all types of reported generation. As the generation fleet continues to shift toward gas-fired units, and the overall age of the fleet reduces, new emerging trends must be examined to identify common outage concerns across fuel types.
- NERC, through the GADSWG, should trend forced outage rates to determine if there are immediate concerns with newly installed generation.
- NERC, through the GADSWG, should examine outage cause codes for specific equipment types (e.g., generator, boiler, turbine, etc.)

Appendix D: Analysis of Demand Response Data

Overview

In 2016, the DADSWG continued efforts to improve data collection, reporting through outreach, and developing of training materials. The outreach efforts developed a process for annual attestation of BAs and Distribution Providers (DPs) to declare whether they meet the criteria for reporting into DADS. The outreach efforts resulted in a nominal increase in the number of entities reporting into DADS, indicating that the population that has been reporting into DADS is representative of the demand response programs in operation. Future DADSWG efforts are focused on improving data collection, updating existing materials and developing additional guidance documents, maintaining data quality, and providing observations of possible demand response contributions to reliability.

Demand Response Programs

Demand Response Registered Program data provides important information about the individual programs that include product and service type, relationships to other entities and programs, and monthly registered capacities. DADS data is reported semiannually as summer and winter seasons with the summer season representing program data from April 1 through September 30 and the winter season representing program data from October 1 to March 31 of the following year. This report includes data reported through September 2016.

BAs and DPs that administer demand response programs that have been commercially in service for at least 12 months with 10 MW or more of enrolled capability are required to report into DADS. In accordance with two 2015 FERC orders[113], reporting by Purchasing-Scheduling Entities and Load-Serving Entities was discontinued.

Registered Capacity

Figure D.1 represents the registered capacity MW for all demand response registered programs in NERC; registered capacity for summer is based on August of each year, and winter is based on January of each year. The total registered capacity in summer has increased slightly since 2013 but remained relatively flat from 2015. However, the winter capacity experienced a 12.7 percent increase from 2015. This increase is due to changes in program rules and implementation of new programs. The increase also reflects a continued increase in development of capacity-based demand response programs since 2013.

It is important to note that the demand response registered capacity is considered fungible (resources and associated capacities are interchangeable). For example, an entity's reported demand response program may be an aggregation of individual resources and each year the individual resources could be from different sources and programs.

[113] Orders RR15-4-000: http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order_RBR_ROP_20150319_RR15-4.pdf and RR-15-4-001: http://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order_RBR_ROP_10152015_RR15-4.pdf

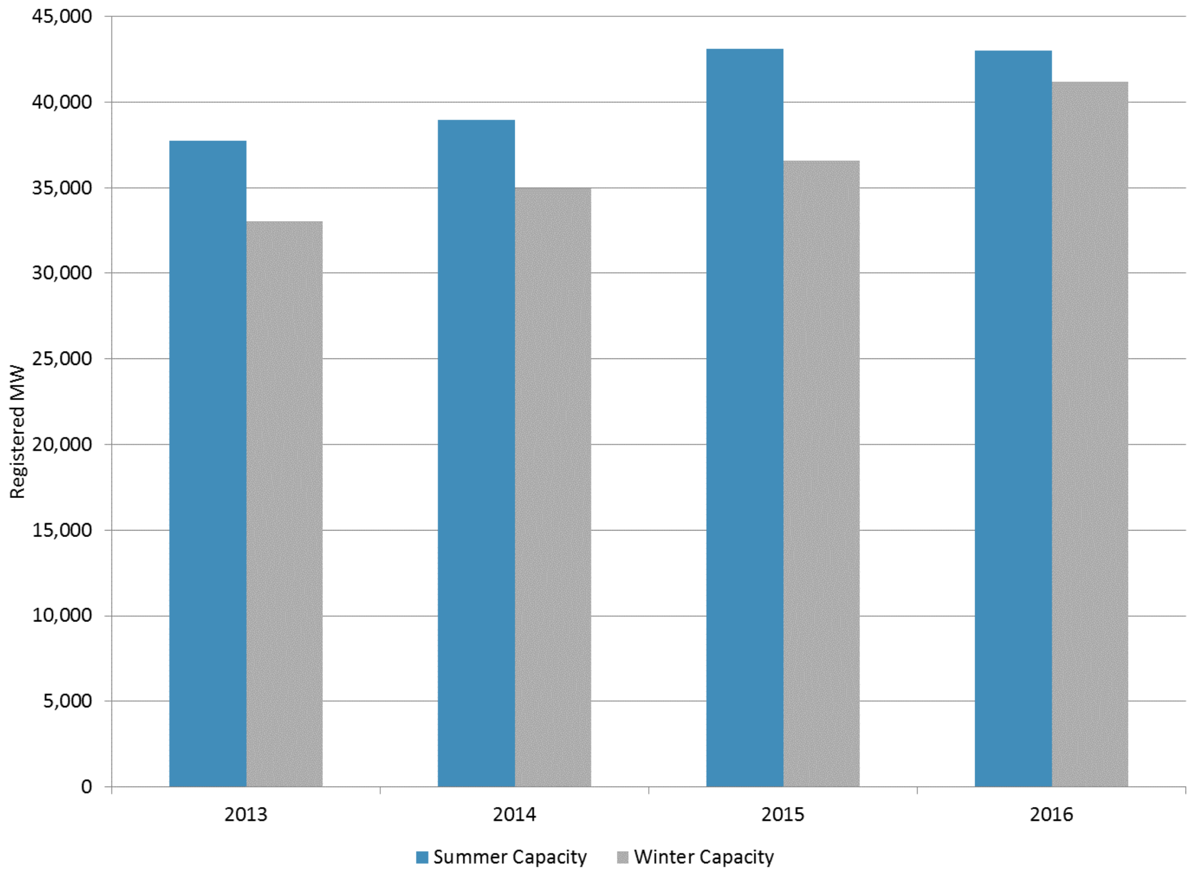
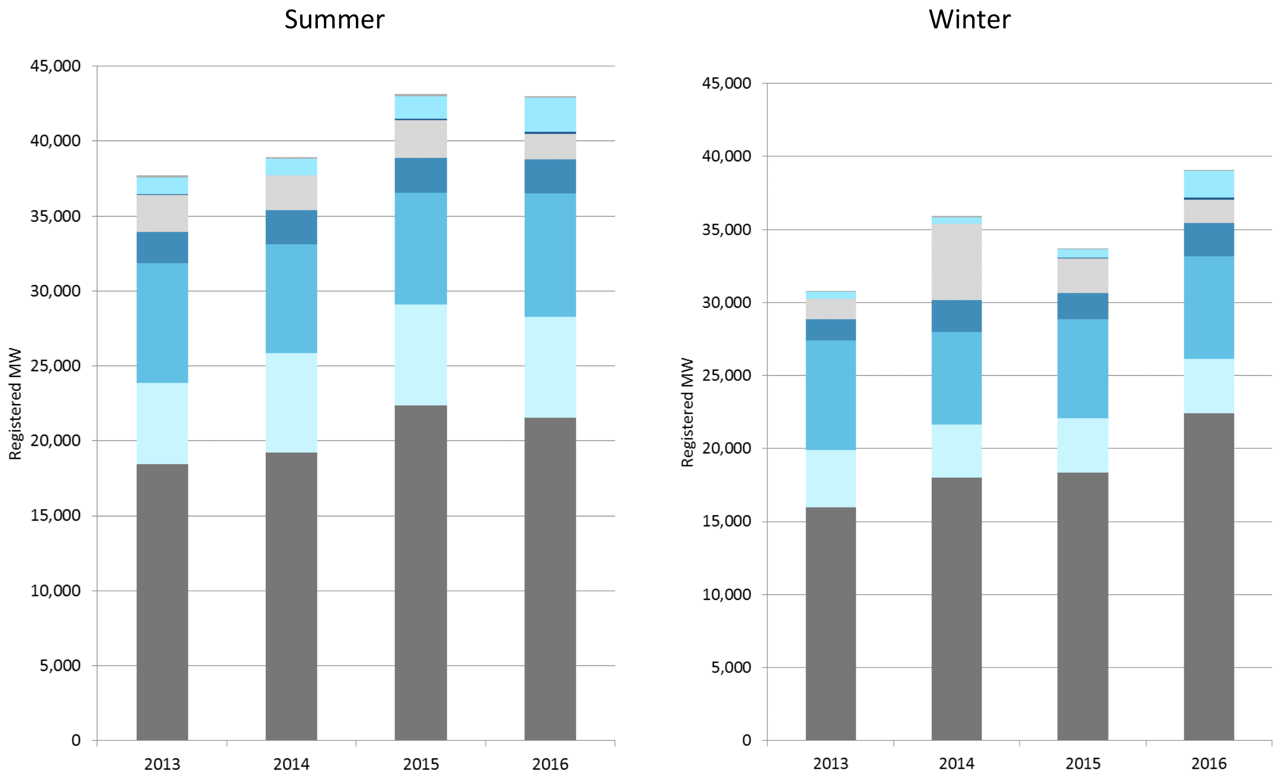


Figure D.1: Registered Demand Response Capacity MW by Season for All Registered Programs, 2013–2016

Product and Service Types

The webDADS portal collects information about demand response programs based on product type and product service type. Current product types in DADS include Energy, Capacity, and Reserves. **Figure D.2** shows the registered capacity MW of demand response across NERC for Summer 2013–2016 and Winter 2013–2016 by reported product and service type.



Product Type	Service Type
Voluntary	Voluntary
Emergency	Emergency
Regulation	Regulation
Reserves	Non-Spinning Reserves
	Spinning Reserves
Capacity	Interruptible Load
	Direct Control Load Management
	Load as a Capacity Resource

Figure D.2: Registered Demand Response Capacity MW by Service Type and Season, 2013–2016

A review of available capacity registered for each service type supports the following observations:

Summer Registered Program:

- The total of registered program enrollments remained stable.
- Increases in emergency and interruptible program enrollments were offset by decreases in load as a capacity resource and nonspinning reserves.
- There was a nominal reduction in summer registered program MW (approximately 100 MW).
- There were anecdotal reports of reductions in load as a capacity resource due in part to changes in environmental regulations for emergency engines.

Winter Registered Program:

- New emergency programs in two Regions have doubled the registered MW over Winter 2015.
- Interruptible load increased due to existing program that began reporting in Winter 2015/2016.

- There was an increase in load as a capacity resource that occurred primarily from the implementation of new wholesale market demand response programs in a single Region.

Demand Response: Reliability Events

Demand response programs are deployed by system operators that are monitoring conditions on the grid. Demand response program rules may require advanced notification for the deployment of these resources that can be several hours ahead of when the emergency condition actually occurs. As the potential for the emergency condition approaches, many operators have more responsive demand response resources that may be deployed with as little as 10 minutes of notification to ramp and curtail load.

Reliability event reasons reported and summarized in DADS are categorized as one of three types of events where demand response supports the BPS: forecast or actual reserve shortage, reliability event, and frequency control.

Reserve shortage events tend to be driven by extreme weather events. For example, the Polar Vortex of 2014 or extreme heat conditions seen on the East Coast and Northeast during 2013 and the West Coast during the summer of 2015. Reliability events can occur at almost any time, day, or month. These can typically be caused by a large number of unit trips or extreme weather that occurs during periods when the generation fleet is going through fleet maintenance periods in the shoulder months. Frequency control reliability events are a type of event that is more local and in isolated areas. For example, a large unit trip may cause a frequency disturbance which is then arrested by the instantaneous tripping of loads using under-frequency relays.

Figure D.3 shows demand response events reported into DADS from January 2013 through September 2016, grouped by month for the four years of event data.[114] The black diamond in each column indicates the number of calendar days in a month when demand response was deployed for a reliability event. The stacked bars show the number of days that demand response events occurred in each NERC Region. When the stacked bar exceeds the black diamond, it is an indication that multiple Regions had demand response events on the same day within the month.

[114] Event data for October 2016 through December 2016 is not reported until after publication of this report.

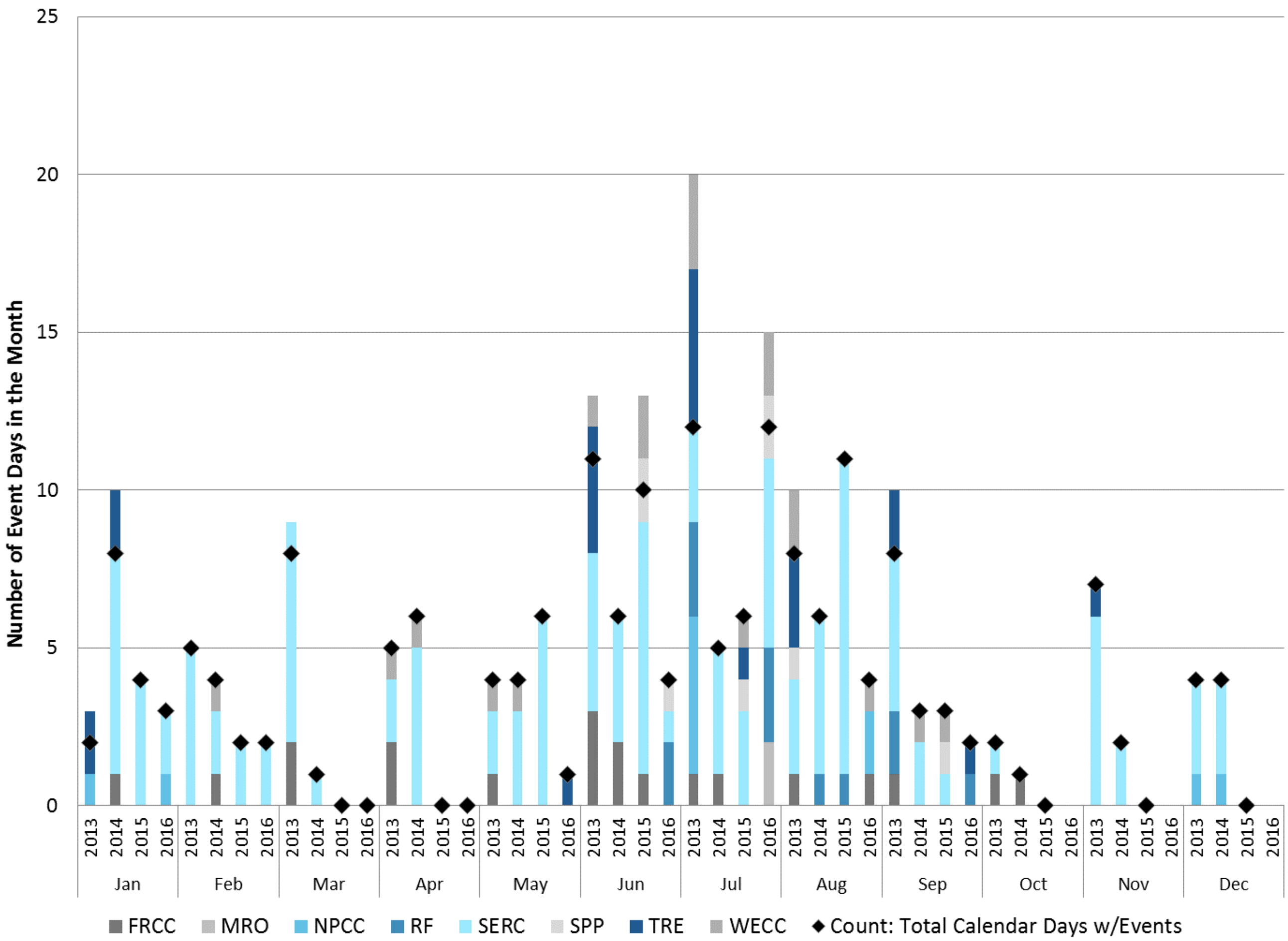


Figure D.3: Demand Response Events by Month and Region, 2013–2016

The peak number of events of DR capacity during this four-year period occurred around the summer peak season, and was especially evident during June and July of 2013. The second highest number of demand response deployments occurred during July of 2016. While there were deployments in several other months in 2016, overall the frequency of deployment events was lower than the previous three years. For example, the Summer[115] of 2015 had 36 calendar days with deployments while the Summer of 2016 had 23 calendar days with deployments (a 36 percent drop in the number of calendar days during which demand response was deployed.). The impact of the Polar Vortex is also evident in the number of days and Regions that dispatched demand response in January 2014. Winter deployments for 2015 and early 2016 were down from 2014, due to warmer weather without the severity of the Polar Vortex events that occurred in 2014.

Figures D.4 and **Figure D.5** represent reliability events from a slightly different perspective. In this case, the cumulative dispatched MW by Region illustrates the locational aspects of the utilization of demand response. The amount of deployed capacity is typically associated with the severity of the events—the more demand response dispatched indicates the greater need for the service it provides. This is evident in 2013 where the high number of deployments shown in **Figure D.3** show a corresponding increase in deployed cumulative dispatched capacity in several Regions in **Figure D.4**. It should be noted that the summer of 2016 had a marked drop in the dispatched capacity from earlier years. However, all Regions deployed demand response in 2016 with most of the capacity being deployed in NPCC and SERC. There was one event in TRE during the summer of 2016 involving a deployment of almost 1000 MW of Load in response to a frequency excursion caused by a large unit trip.

[115] Defined as April 1- September 30

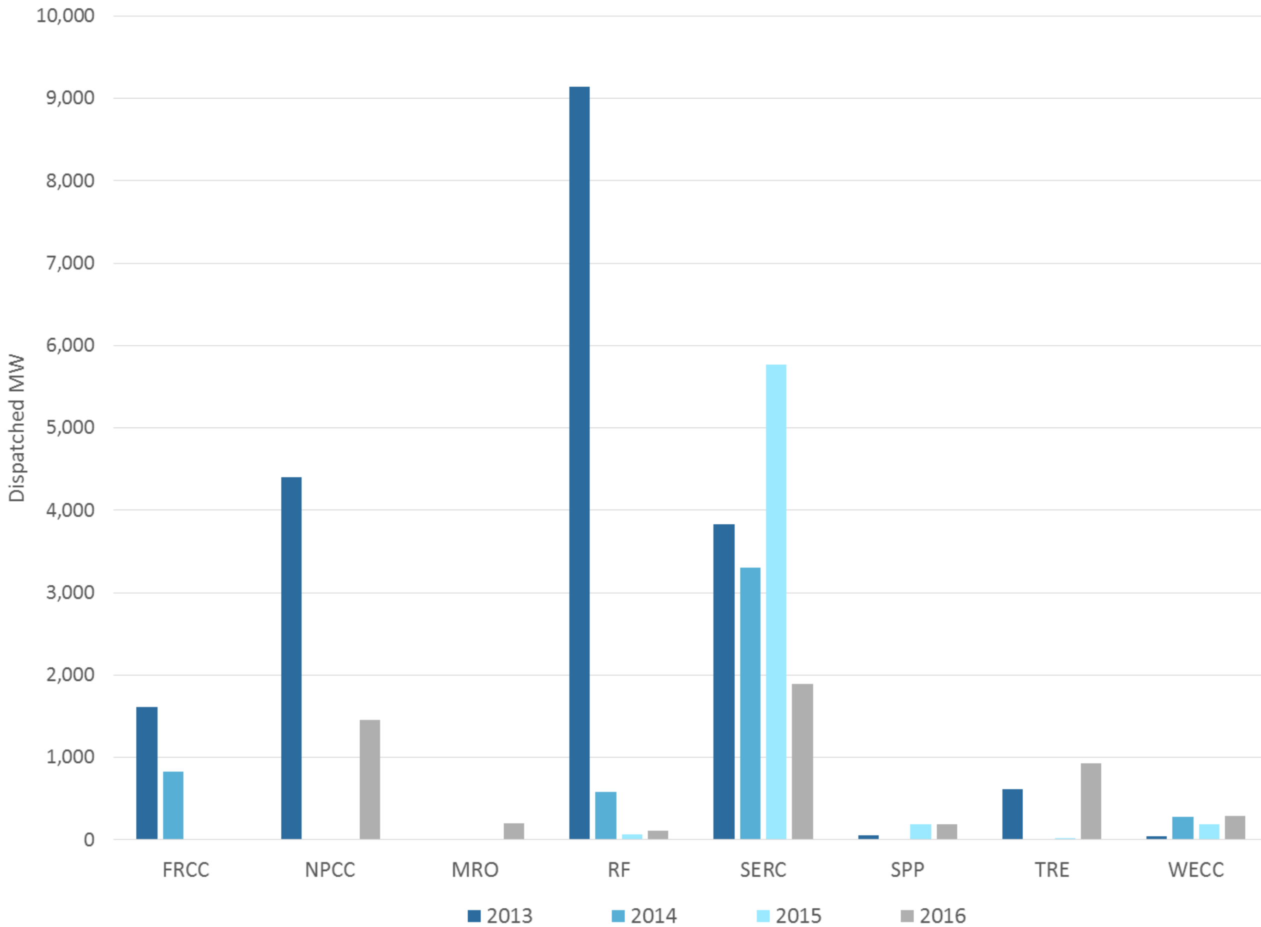


Figure D.4: Cumulative Dispatched MW by Region for Summer Demand Response Events, 2013–2016

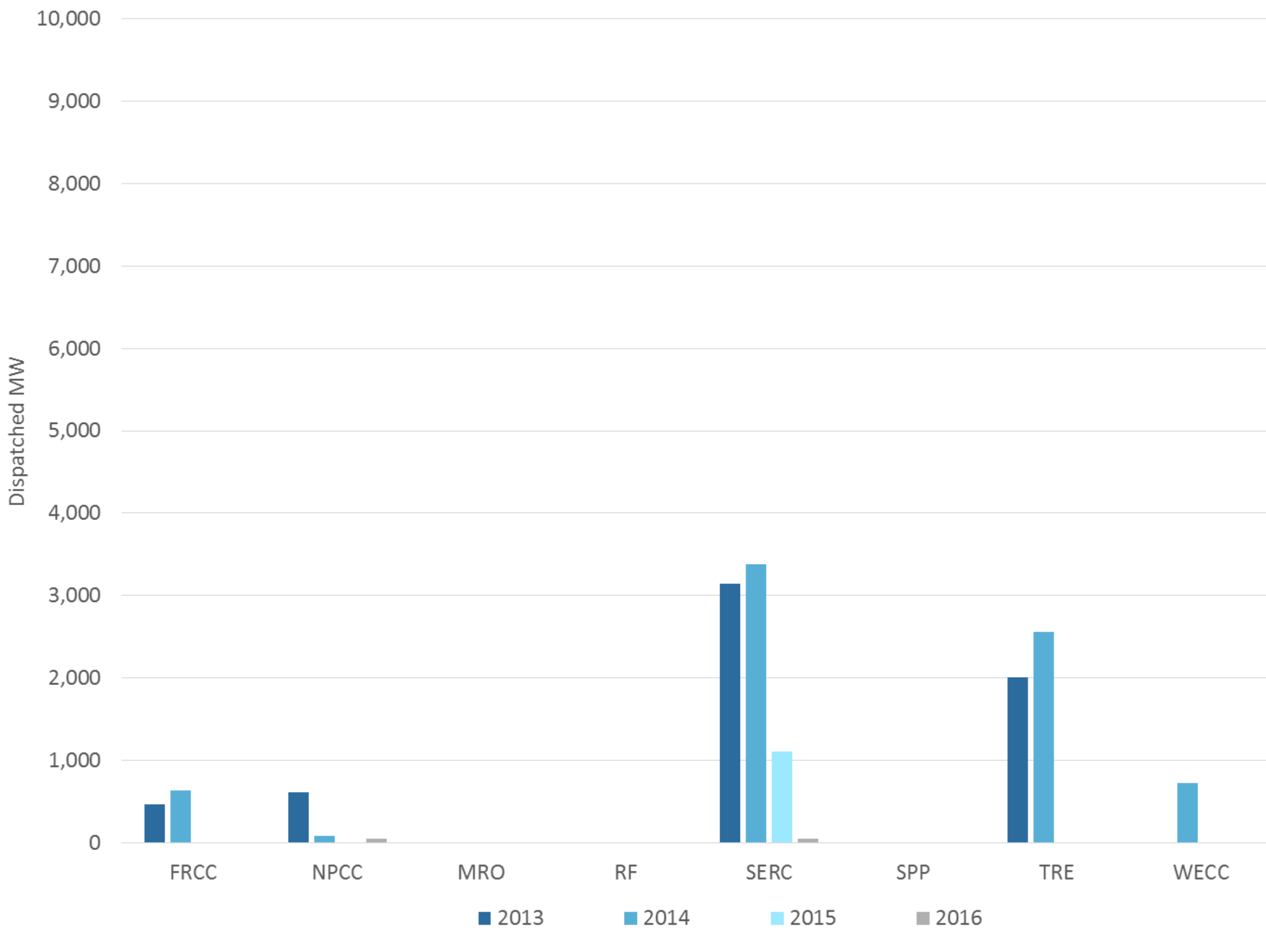


Figure D.5: Cumulative Dispatched MW for Winter Demand Response Events, 2013–2016

Figures D.6 and **Figure D.7** show the cumulative amount of capacity deployed by the duration of the events. The majority of the Dispatched MW during the 2014 and 2015 years are in events lasting less than 60 minutes. Deployments associated with the heat wave over the East Coast and Northeast during the summer of 2013 tended to show much longer deployments, typically lasting four hours or more. Similarly, the events during the Polar Vortex phenomenon were much longer and extended over a broader stretch of the Southeastern US.

The frequency at which demand response is deployed may be a function of the demand response program's design and not an indication of extensive reliability issues in a Region. For example, as shown in Figure D.3 note that in the SERC Region, demand response was deployed nearly every month during the analysis period. When viewed by event duration, the number of dispatched MW for these events shows that these deployments predominantly last for less than one hour.

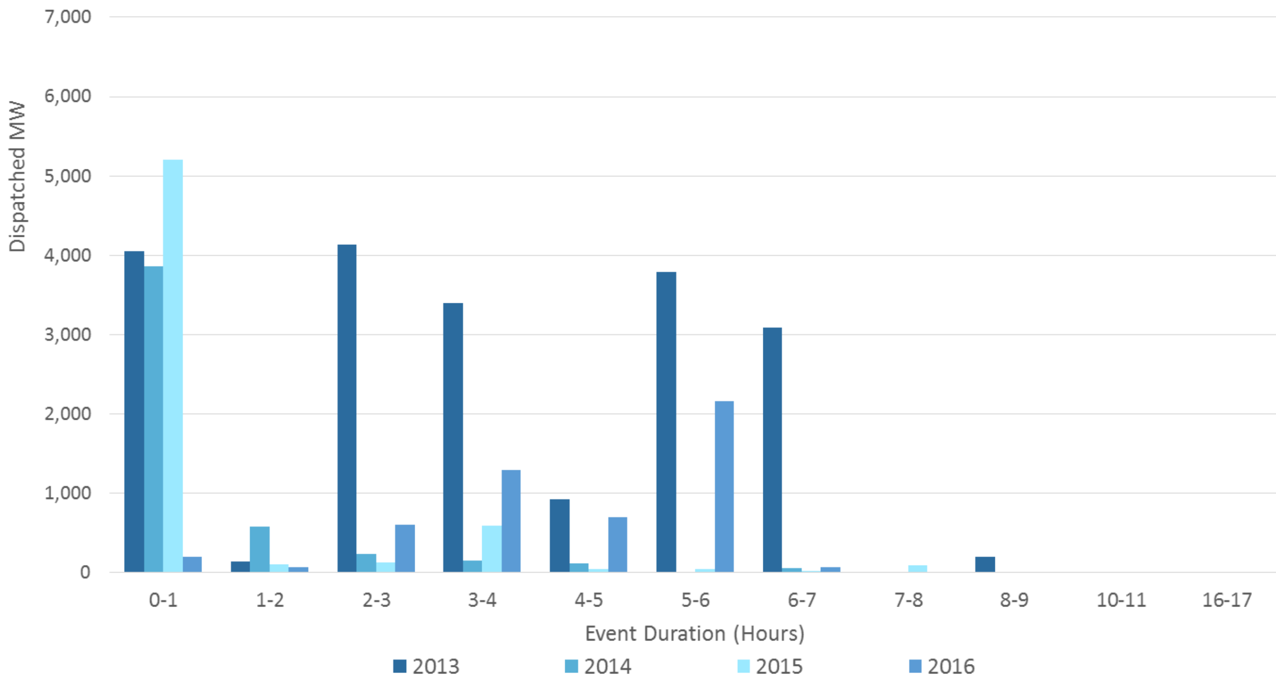


Figure D.6: Cumulative Dispatched MW by Duration for Summer Demand Response Events, 2013–2016

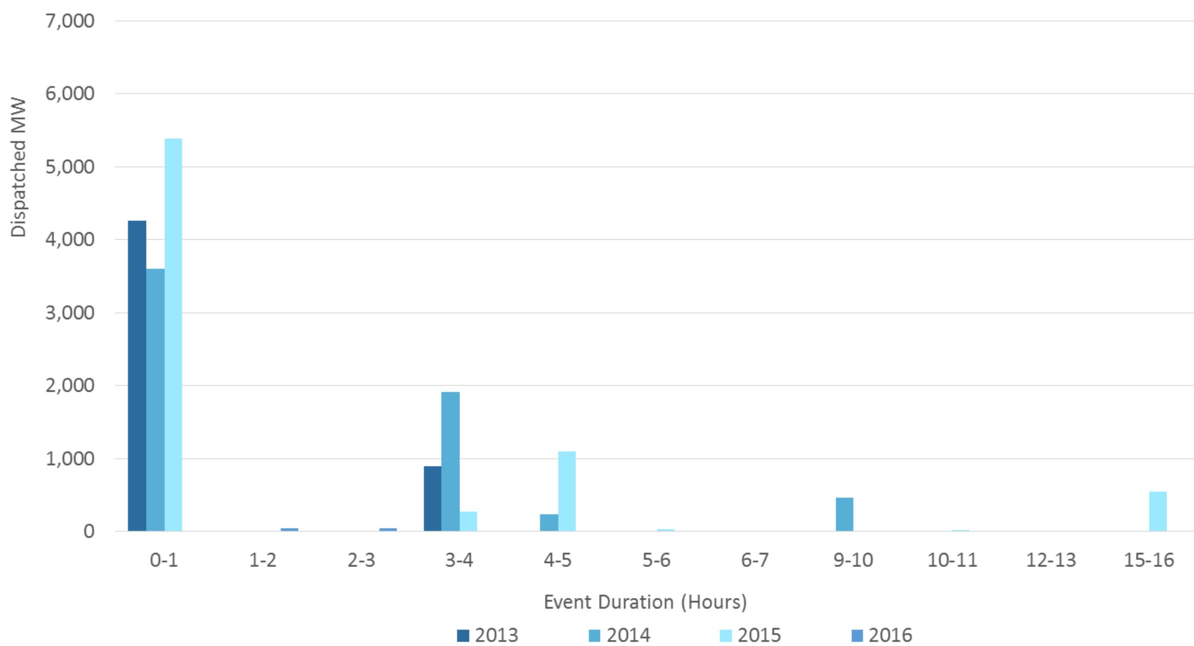


Figure D.7: Cumulative Dispatched MW by Duration for Winter Demand Response Events, 2013–2016

DADS Metrics

In 2015, four DADS metrics were developed by the DADSWG and approved by PAS. These metrics are described in **Table D.1**.

Table D.1: DADS Metrics

Title	Purpose
DADS Metric 1: Realized Demand Reduction of Event Deployment by Month	Shows the amount of demand response reduction (in MW) provided during all the reliability events deployed in a given month by time of day.
DADS Metric 2: Dispatched Demand Response MW by Service Type	Reflects the cumulative megawatts of demand reduction dispatched by service type in reliability event days per month at the NERC or Region level
DADS Metric 3: Realized Demand Response MW by Service Type	Reflects the cumulative time weighted megawatts of demand reduction realized by service type in reliability event days per month at the NERC or Region level
DADS Metric 4: Demand Response Events by Month – Dispatched vs. Realized	Allows for the creation of a demand response realization rate for reliability events to be established and trending

The DADSWG has completed initial analysis of Metrics 2, 3, and 4; the results are provided below. The work group will continue to monitor and analyze the DADS metrics and will provide additional information in future *State of Reliability* reports.

DADS Metric 1

While all metrics require software changes to DADS, Metric 1 requires extensive additional processing and formatting to support reporting this metric.

DADS Metric 2

The amount and types of demand response dispatched by year illustrates how much weather can affect the deployment of demand response. **Figure D.8** and **Figure D.9** show the cumulative dispatched MW of demand response by service type for summer and winter, respectively. During the summer of 2013, the cumulative amount of demand response deployed over all events was nearly 20,000 MW with over 70 percent of the demand response dispatched from load as a capacity resource and nearly equal amounts of direct load control and Interruptible Load. The summers of 2014 and 2015 were much milder, resulting in few deployments and more conservative utilization of demand response, primarily from direct load control and interruptible load. During the summer of 2016, deployments included a marked increase in the amount of demand response providing spinning reserves.

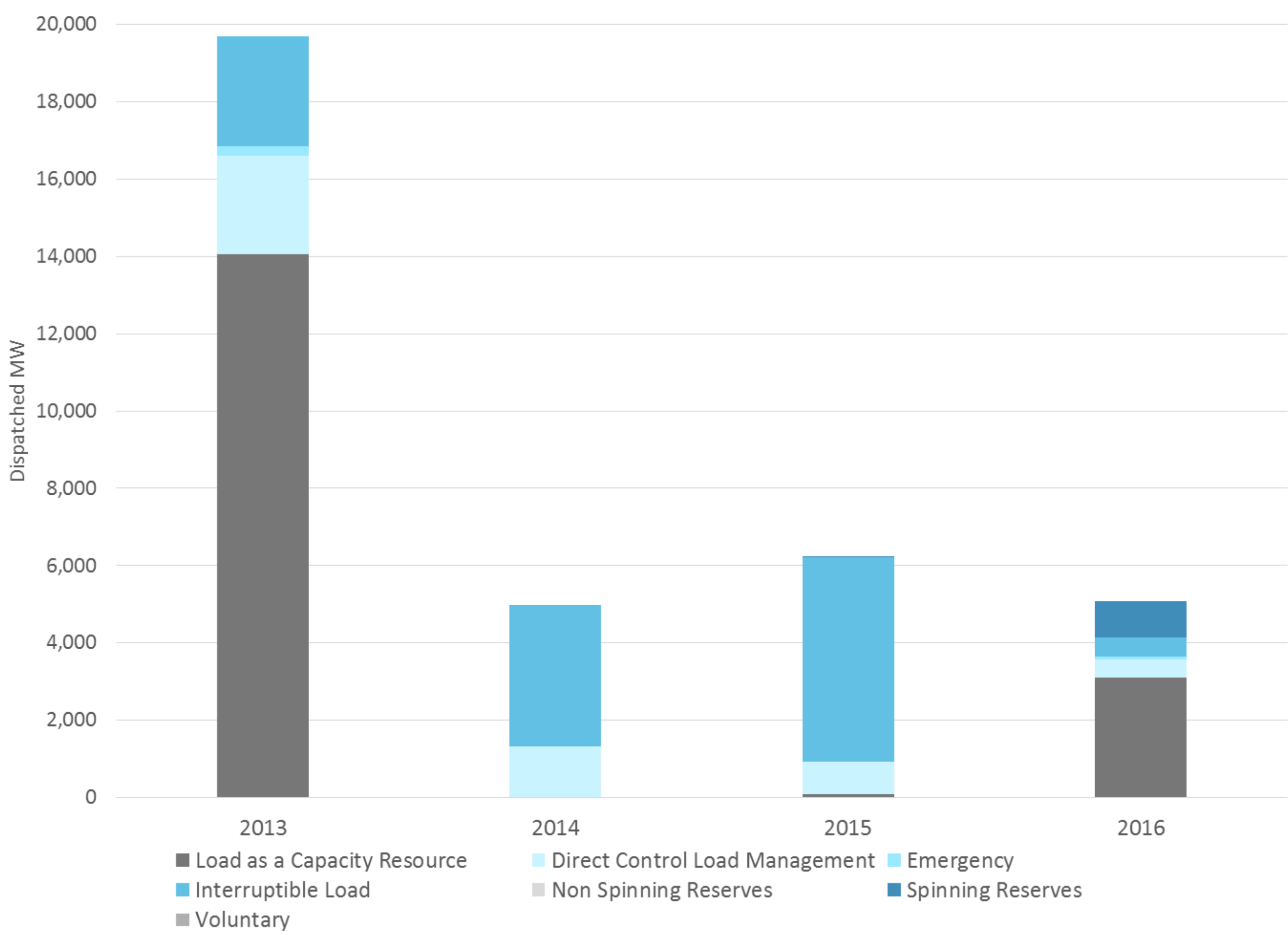


Figure D.8: Cumulative Dispatched MW by Service Type for Summer Demand Response Events, 2013–2016

Winter deployments of demand response are much less extensive as reflected in the cumulative MW dispatched each winter in the analysis period (**Figure D.9**). Deployments during the analysis period were primarily to demand response provided from interruptible load resources. During the winters of 2013 and 2014, demand response providing reserves (spinning and nonspinning) accounted for almost one-third of the cumulative dispatched MW each year.

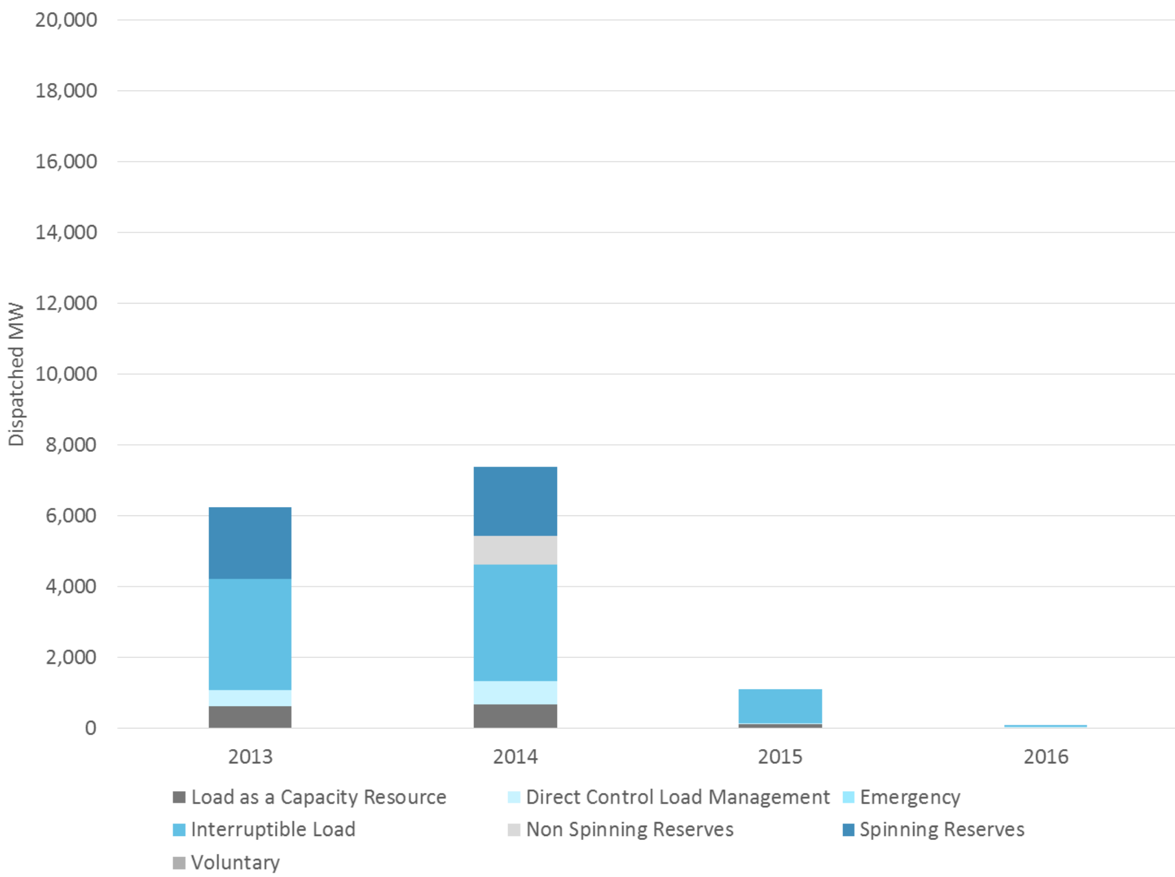


Figure D.9: Cumulative Dispatched MW by Service Type for Winter Demand Response Events, 2013–2016

DADS Metric 3

Figures D.10 and **Figure D.11** report the performance of demand response resources based on service type for summer and winter, respectively. Average hourly response is calculated for each event as the sum of reported response divided by the number of dispatched hours reported with the event.

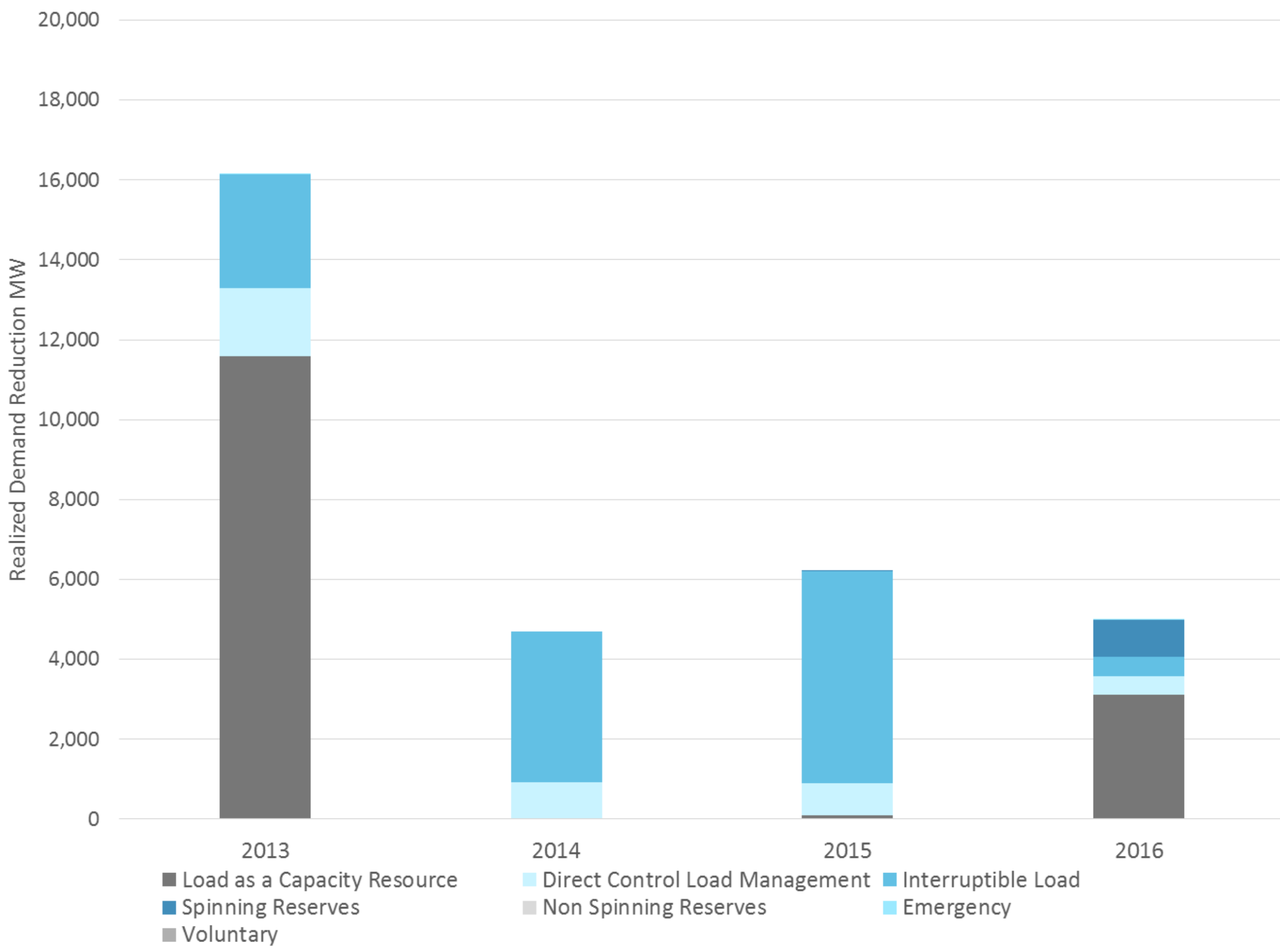


Figure D.10: Cumulative Realized Demand Reduction MW by Service Type for Summer Demand Response Events, 2013–2016

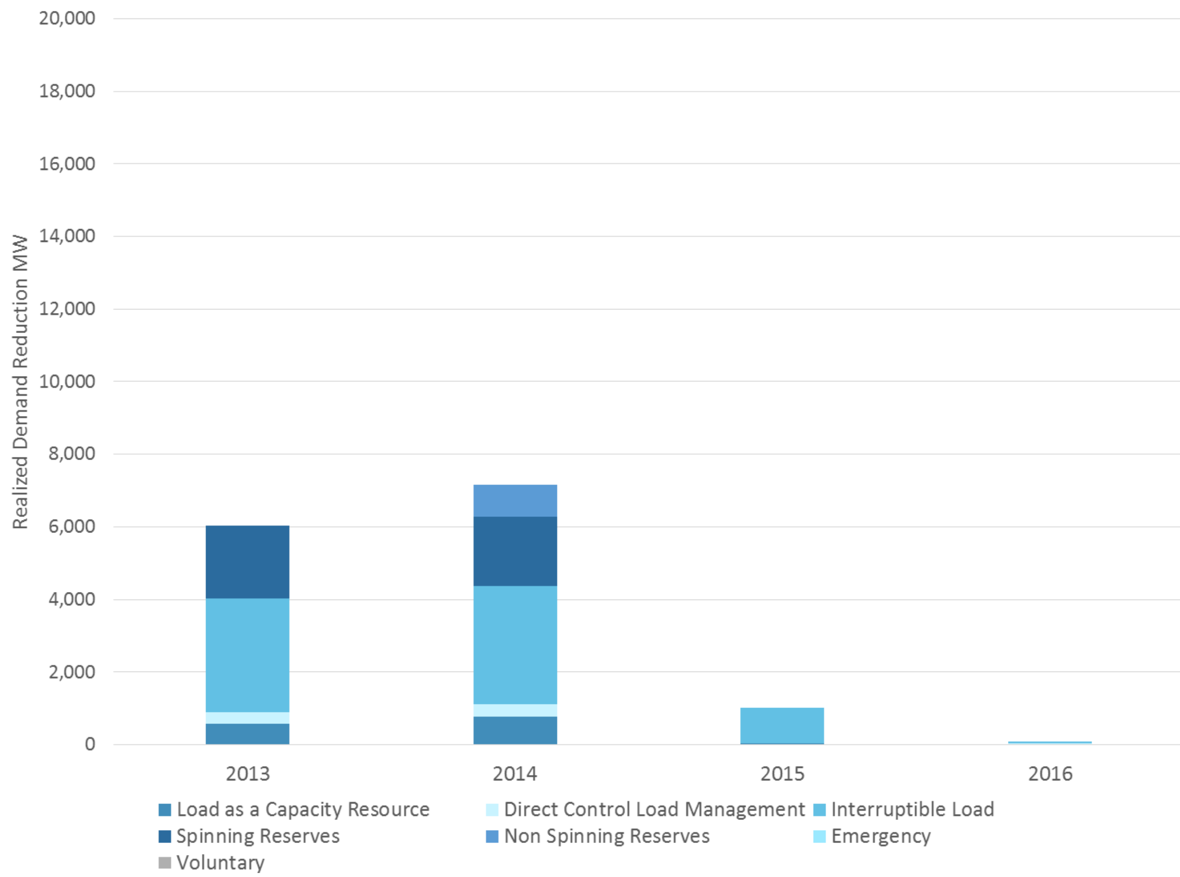


Figure D.11: Cumulative Realized Demand Reduction MW by Service Type for Winter Demand Response Events, 2013–2016

DADS Metric 4

The effectiveness of demand response to support reliability is illustrated by a comparison of the cumulative dispatched MW to the average realized reduction MW each season and year. **Figures D.12** and **Figure D.13** show the cumulative dispatched MW and corresponding performance of all demand response types deployed in a season for each year of the analysis period.

During the summer of 2013, demand response performed at 82 percent of its committed capacity (**Figure D.12**). This includes the deployment of voluntary and emergency types of demand response, which typically performs at a much lower rate (about 15 percent of registered) than other categories of demand response. The voluntary and emergency types of demand response deployed in the summer of 2013 represented 1.3 percent of all dispatched MW. When the summer of 2013 performance was evaluated without the voluntary and emergency types of demand response, there was a slight increase in performance, from 82.1 percent to 82.9 percent. Performance during the summers of 2014 through 2016 was well above 90 percent, due to the amount and types of demand response deployed.

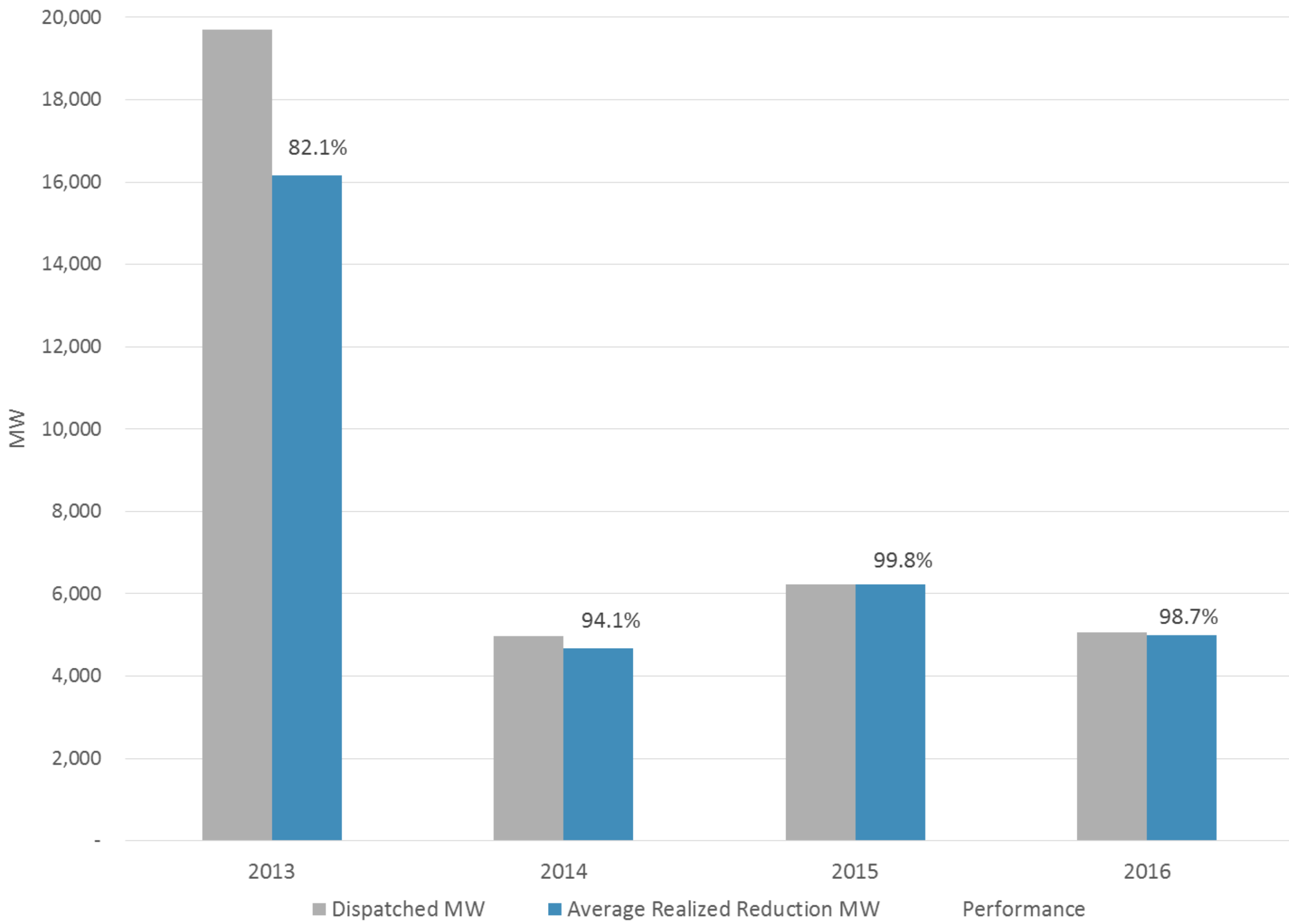


Figure D.12: Demand Response Performance for Summer Demand Response Events, 2013–2016

As previously stated, fewer MW of demand response were deployed in the winter seasons. Performance exceeded 96 percent during events in the winters of 2013–2014 and 90 percent in 2015 (**Figure D.13**). Fewer than 100 MW of demand response were deployed in the winter of 2016.

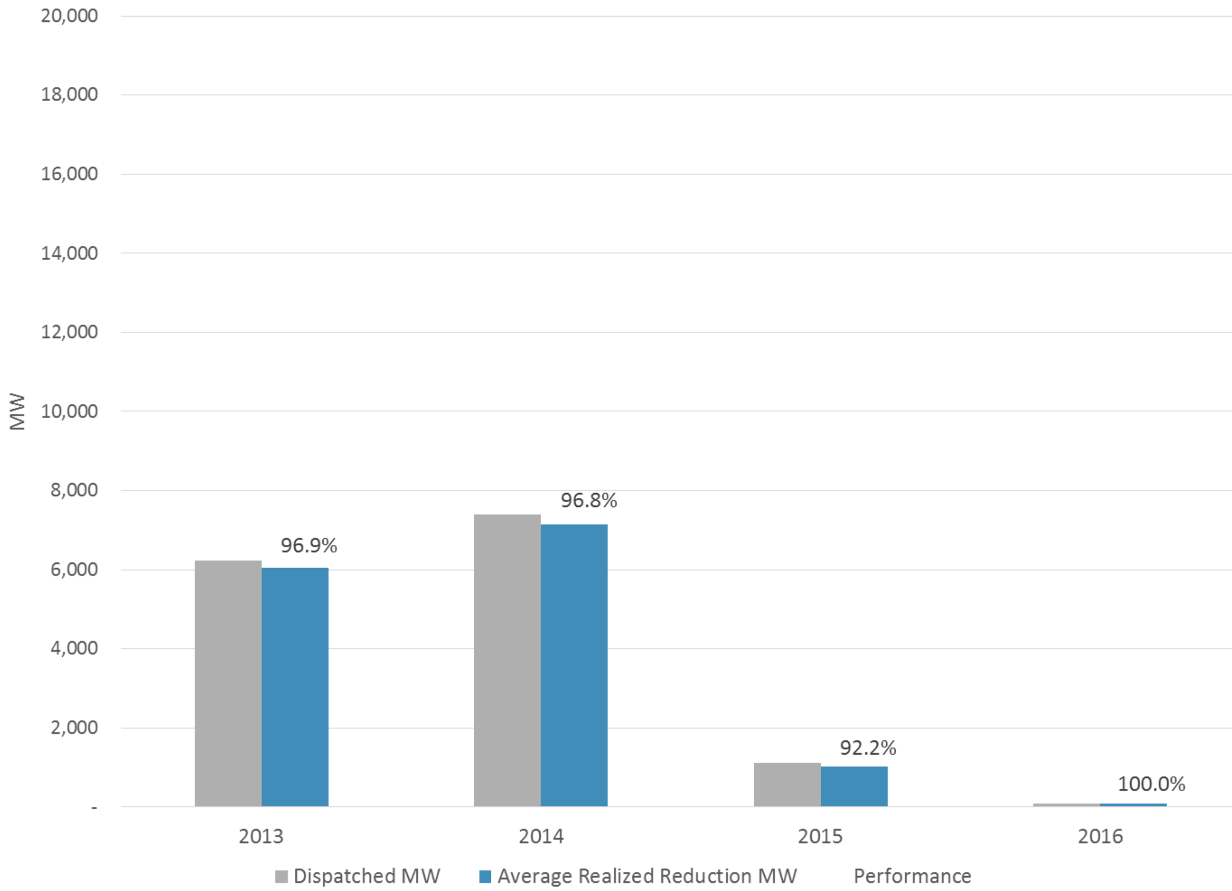


Figure D.13: Demand Response Performance for Winter Demand Response Events, 2013–2016

Looking Ahead

The DADSWG is focused on improving the quality of the demand response data collected by NERC, and this will provide a better perspective on how this type of resource is being used to support reliability. To achieve this objective, the following initiatives are planned for 2017 and beyond:

- Improvements to the DADS application to better support data reporting capabilities for market-based demand response programs that support reliability.
- Development and implementation of training to improve data reporting.
- Participate in the evaluation of demand response data used in the Long-Term Reliability Assessment (LTRA) and other NERC special assessments.

Appendix E: Reliability Indicator Trends

This appendix contains detailed supporting analysis for most of the reliability indicators (metrics) listed and assigned trending values in Chapter 4, Table 4.1. Any metric that particularly speaks to BPS reliability trend changes in 2016 is explained to some degree in Chapter 4. Those metrics might be completely covered in that chapter or might have more detailed analyses in this appendix. For those metrics that generally speak to reliability in any year but did not identify trend changes in 2016, their analyses are completely contained in this appendix.

An exception is M-4: Interconnection Frequency Response; this metric is particularly important given current changes to the BPS resource mix that might threaten adequate ERSs. Description of the focused actions regarding M-4 that BPS stakeholders and regulators took in 2016 are detailed in Chapter 2: 2016 Reliability Highlights rather than in Chapter 4: Reliability Indicator Trends, but all detailed analysis of M-4 is contained in this appendix.

M-1 Planning Reserve Margin

Background

This metric demonstrates the amount of generation capacity available to meet expected demand. It is a forward-looking or leading metric. PAS and Reliability Assessment Subcommittee are collaboratively working to determine if there is a better metric for this report.

This metric is reported in the annual LTRA[116] and the Summer[117] and Winter[118] Assessments. NERC's 2015 LTRA[119] discussed the observed tightening of reserve margins in several assessment areas. Similarly identified have been changes to the resource mix as some areas have diminishing resource diversity and flexibility. These two issues in conjunction could present additional operational issues even if an assessment area is showing sufficient planning reserve margins.

The most recent LTRA[120] indicates, as shown in **Figure E.1**, that all Regions project sufficient reserve margins in the near term (five year window).[121]

[116] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf
[117] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20SRA%20Report_Final.pdf
[118] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/WRA%202016_2017_final.pdf
[119] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf
[120] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf
[121] The reserve margins in Figure E.1 reflect the most critical peak season for each reporting entity when reserves are lowest. This includes consideration of whether each entity is summer or winter peaking.

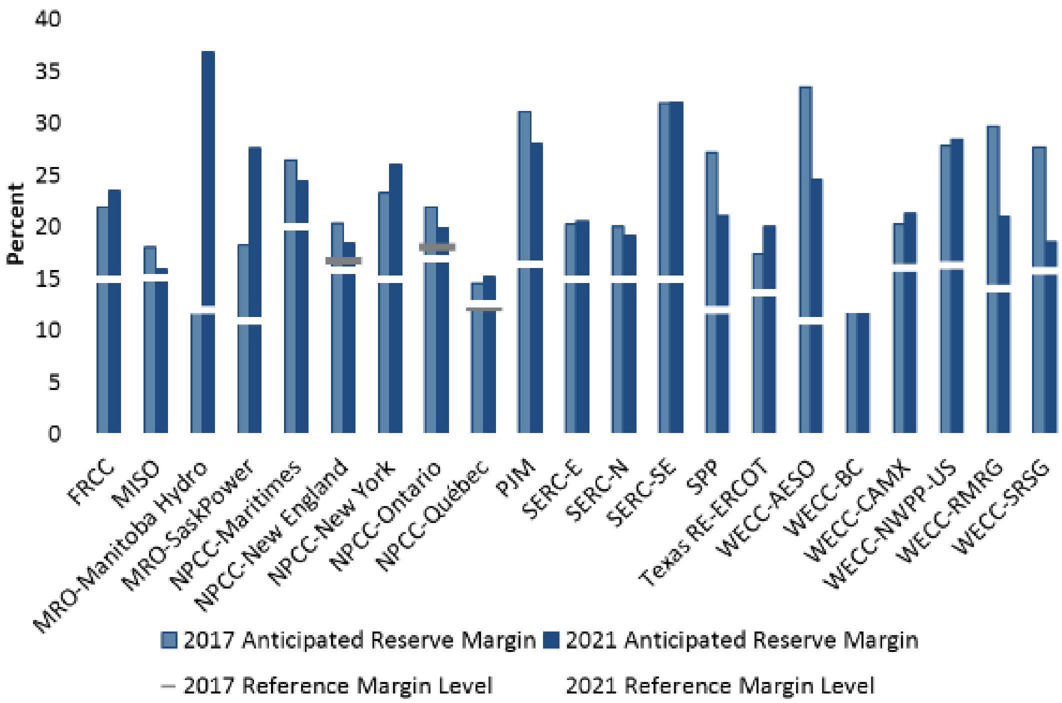


Figure E.1: M-1 Planning Reserve Margin

M-3 System Voltage Performance

Background

This metric was retired from the monitored set of metrics in 2014.

Future Development

Maintaining system voltage and adequate reactive control remains an important reliability performance objective that must be incorporated into the planning, design, and operation of the BES. The ERSWG developed a November 2015 framework report[122] that recommended a set of voltage measures with PAS assigned to develop data collection to support Measure 7: Reactive Capability on the System.

During 2016, PAS developed and conducted a voluntary data collection and released the data for analysis to the SAMS for analysis of Measure 7 as a potential voltage and reactive metric.

M-4 Interconnection Frequency Response

Summary

This metric measures primary frequency response trends for each interconnection so that adequate frequency support is provided to arrest and stabilize frequency during large frequency events. The statistical trends discussed for operating years 2012–2016 should be considered within the context of longer term trends analyzed and discussed in the *Frequency Response Initiative Report* from 2012.[123]

Figure E.2 shows the decline in frequency response since 1994 for the Eastern Interconnection that was discussed in the 2012 *Frequency Response Initiative Report* with data and the short-term trend for the operating years 2012–

[122] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf
[123] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

2016 added. While there is insufficient data to show the same historic time trends for the Western, ERCOT, and Québec Interconnections, many of the issues that led to the decline in the Eastern Interconnection, such as incorrect governor deadband settings, generator controls, and plant-level control interactions have been observed in those interconnections.

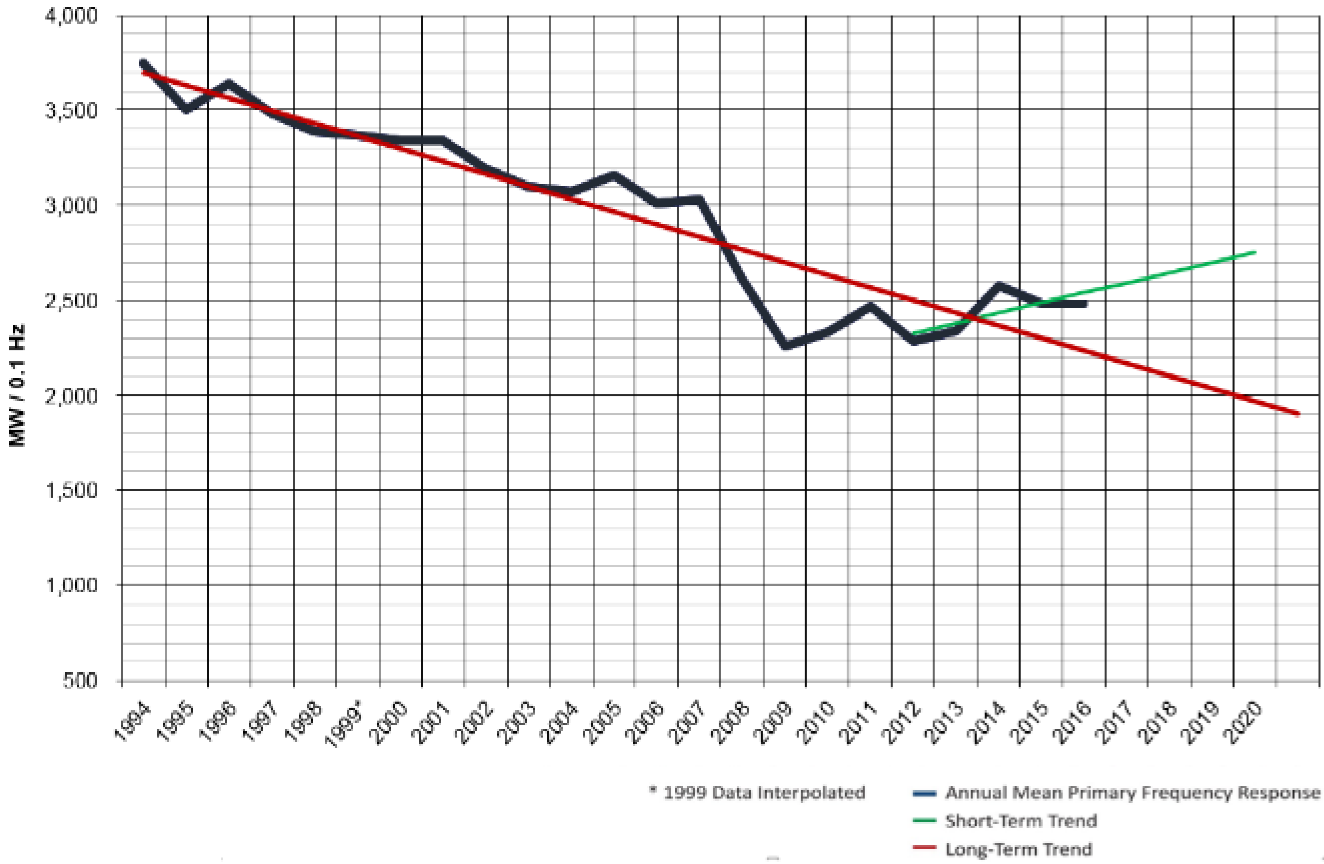


Figure E.2: Eastern Interconnection Frequency Response Trend[124]

Statistical Trends in Frequency Response by Interconnection

NERC applies statistical tests to interconnection frequency response datasets. An operating year, for frequency event purposes, runs from December of the previous year through November of that year. For the 2012–2016 operating years, historical frequency response was statistically analyzed to evaluate performance trends by interconnection. An increasing trend over time indicates that frequency response is improving in that interconnection. It should be noted that in the 2016 operating year no interconnection had an M-4 frequency event where the frequency response performance was below its IFRO. It is important to note that there is a difference between the measured frequency response for a given event and the amount of response that was actually available at the time of the event. Measured response varies depending on starting frequency as well as the size of the resource loss. The following are overall observations and recent trends for each interconnection:

[124] The source of the Frequency Response data from 1994–2009, displayed in Figure E.2, is a report by J. Ingleson & E. Allen, "Tracking the Eastern Interconnection Frequency Governing Characteristic" that was presented at the 2010 IEEE PES. The source of the data from 2010 and 2011 are the daily automated reliability reports. The data for 1999, designated by *, was interpolated. Figure E.2 also reflects a change in the method for calculation of frequency response in 2009 (See FRI Report p. 25).

- Eastern Interconnection frequency response (FR) time trend, over the 2012–2016 operating years, was neither statistically increasing nor decreasing.[125] The mean FR in 2016 statistically significantly increased compared with 2013 but was similar to 2014 and 2015. The 2016 median FR was statistically similar to 2014 and 2015. The Eastern Interconnection shows incremental improvements in frequency response performance as demonstrated by higher mean Point C and mean Value B frequencies. This suggests improved primary frequency response during the arresting phase and recovery phase of the events. However, variability increased in 2016 with a higher maximum and lower minimum FR for all years studied. This could be due to a reduced mean resource MW loss and should be monitored in future years. The overall performance trend for the Eastern Interconnection is considered improving, albeit incrementally, due to these results.
- The ERCOT Interconnection has shown a statistically significant increase in frequency response over the 2012–2016 operating years. The mean and the median FR in 2016 was the highest in the five years. The Interconnection has demonstrated higher mean Point C and higher mean Value B frequencies, suggesting improved overall primary frequency response in both the arresting and recovery phases. However, variability increased in 2016 with the lowest Point C observed trending lower since the 2014 operating year. This could be due to an increase in the number of events sampled and should be monitored in future years. Since 2014, the lowest Point C frequency has been decreasing and the lowest Point C to UFLS margin has been smaller each year, which is a trend that should be monitored. The overall performance trend for the ERCOT Interconnection is considered improving due to these results.
- The Québec Interconnection frequency response trend over the 2012–2016 operating years was neither statistically increasing nor decreasing. In the 2015 and 2016 operating years, mean and median frequency response increased, however only the median increase was statistically significant from 2014 to 2016. No clear trend was observed in the mean Point C or Value B frequencies or in the distribution of events. The overall performance trend for the Québec Interconnection is considered to be stable (unchanged) due to these results.
- The Western Interconnection frequency response time trend in the 2012–2016 operating years was neither statistically increasing nor decreasing. There was a statistically significant increase in FR in 2016 versus 2014. The 2016 median FR was numerically higher than in 2014 and 2015. However, the 2016 variance also statistically significantly increased compared with both 2014 and 2015. The Western Interconnection shows incremental improvements in frequency response performance as demonstrated by higher mean Point C and mean Value B frequencies beginning in 2014. This suggests improved primary frequency response during the arresting phase and recovery phase of the events. However, this could be due to a reduced mean resource MW loss and should be monitored in future years. The performance trend for the Western Interconnection is considered to be improving, albeit slightly, due to these results.

In the 2016 operating year, a change in selection criteria was implemented that included frequency events with a smaller MW loss if the event resulted in a sufficient frequency deviation. Note that this change resulted in a larger sample of events for all interconnections as compared to previous years.

Further statistical significance tests were applied to interconnection frequency response datasets with additional correlation analysis on time of year, load levels, and other attributes also conducted. These results and further statistical analysis can be found in the background for the metric.

Background

Stable frequency is a key ALR performance outcome. Frequency response is essential to support frequency during disturbances that result in large frequency deviations as well as during system restoration efforts. Frequency

[125] A statistical test is performed to determine if the time trend line is increasing or decreasing. A statistically significant trend means that the slope, positive or negative, is unlikely to have occurred by chance. The complete statistical analysis can be found in Appendix E.

response (primary frequency control) is comprised of the actions provided by the interconnection to arrest and stabilize frequency in response to frequency deviations. Frequency response comes from automatic generator governor response, load response (typically from motors), and devices that provide an immediate response based on locally detected changes in frequency by device-level control systems. The purpose of the M-4 metric is to monitor frequency response trends for each interconnection so that adequate primary frequency control is provided to arrest and stabilize frequency during extreme frequency events and avoid tripping the first stage of UFLS for each interconnection.

The IFRO is intended to be the minimum amount of frequency response that must be maintained by an interconnection and is reviewed and determined annually in the *Frequency Response Annual Analysis*[126]. Each BA in the interconnection is allocated a portion of the IFRO that represents its minimum responsibility in accordance with Reliability Standard BAL-003-1.[127] The analysis in this chapter shows how the events resulting in the lowest frequency response compare with the IFRO.

Figure E.3 illustrates a frequency deviation due to a loss of generation resource and the methodology for calculating frequency response. The event starts at time t0. Value A is the average frequency from t-16 to t-2 seconds, Point C is the lowest frequency point observed in the first 12 seconds and Value B is the average from t+20 to t+52 seconds. The difference between Value A and Value B is the change in frequency used for calculating primary frequency response. Frequency response is calculated as the ratio of the megawatts lost when a resource trips and the frequency deviation. For convenience, frequency response is expressed in this report as an absolute value. A large absolute value of frequency response, measured in MW/0.1Hz, is better than a small value.

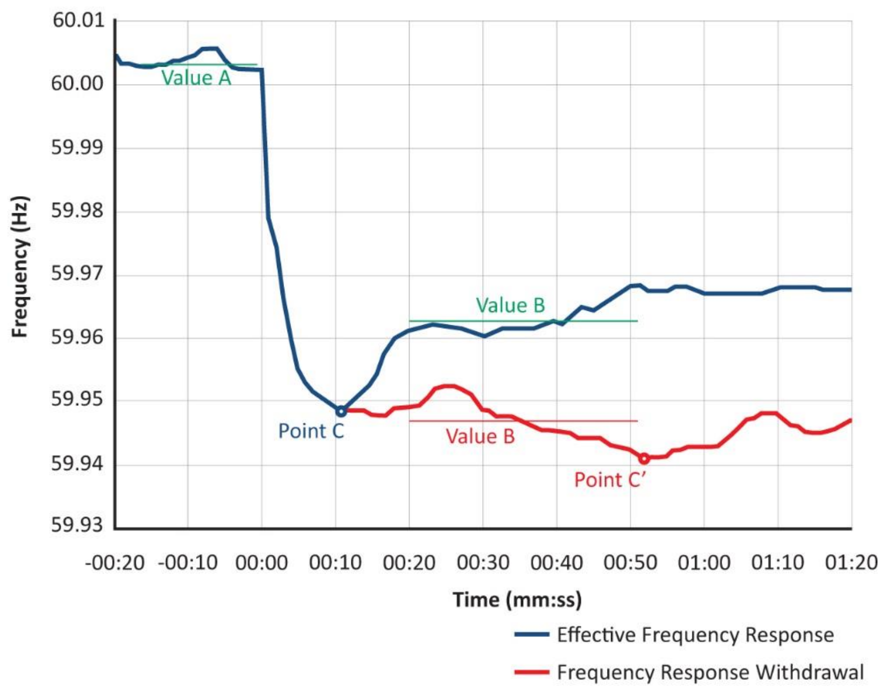


Figure E.3: Criteria for Calculating Value A and Value B

Selected events for frequency response analysis are vetted by the NERC Frequency Working Group (FWG). The event data is used to support Reliability Standard BAL-003-1 in addition to the M-4 metric.

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126 The analysis effective for the 2016 operating year can be found at:
http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/2015_FRAA_Report_Final.pdf

127 http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

The NERC RS has identified issues related to the ability of existing generating resources to provide sustained frequency response including incorrect governor dead-band settings and plant or generator control logic. The NERC OC issued *Reliability Guideline: Primary Frequency Control v1.0 Final*[128] to encourage the industry to address these issues. Additionally, FERC issued a NOPR in 2016[129], seeking comment on FERC's proposal to modify generator interconnection agreements to require that all new generation resources be capable of providing frequency response.

The North American BPS resource mix is changing to integrate an increasing level of inverter-based generation, such as wind turbine and solar, in addition to distributed energy resources and demand response programs. NERC established the ERSWG[130] to assess the impact on reliability resulting from a changing resource mix and developed measures to track and trend reliability impacts including frequency support. The analysis of these metrics may be included in future *State of Reliability* reports in accordance with the adoption of the metrics and data collection processes.

Interconnection Frequency Event Statistics

Table E.1 through **Table E.4** compare the M-4 frequency event statistics for the four Interconnections in accordance with the frequency response methodology shown in **Figure E.3**. It is useful to consider the mean Value B minus Point C to observe whether the frequency characteristics suggest changes in primary frequency response during the arresting and recovery phases. It is also useful to consider the mean and lowest Point C values in relation to the interconnection first-step UFLS relay settings.

In the 2016 operating year, a change in selection criteria was implemented that included frequency events with a smaller MW loss if the event resulted in a sufficient frequency deviation. Note that this change resulted in a larger sample of events for all interconnections as compared to previous years.

Table E.1: Frequency Event Statistics for Eastern Interconnection

Operating Year	Total Number of Events	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (mHz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (mHz)
2012	10	1259	60.001	59.948	59.946	-0.002	0.448	59.937	0.437
2013	32	1157	60.000	59.950	59.948	-0.001	0.450	59.909	0.409
2014	34	1212	59.995	59.947	59.948	0.001	0.447	59.910	0.410
2015	36	1103	59.996	59.948	59.950	0.002	0.448	59.928	0.428
2016	61	938	59.999	59.956	59.959	0.003	0.456	59.930	0.430

The following are observations from **Table E.1**:

- There is an increasing mean B-C margin each year since 2012, suggesting incremental improvements in the Eastern Interconnection frequency response.
- The lowest Point C to UFLS margin has increased each year, beginning in 2013.

[128] http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf
[129] https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-3.pdf
[130] http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx

- Point C and Value B frequencies have both trended higher since 2014. This trend should be monitored in light of a reduced mean resource loss in 2016.
- For frequency events in the 2016 operating year, the lowest Point C frequency was above the first-step UFLS setting of 59.5 Hz[131] by 430 mHz, which is a slightly larger margin than in 2015.

Table E.2: Frequency Event Statistics for ERCOT Interconnection

Operating Year	Total Number of Events [132]	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (Hz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (Hz)
2012	46	672	59.995	59.825	59.872	0.047	0.525	59.729	0.429
2013	40	721	59.997	59.836	59.896	0.061	0.536	59.732	0.432
2014	33	639	59.996	59.850	59.900	0.050	0.550	59.744	0.444
2015	34	642	59.999	59.866	59.912	0.046	0.566	59.728	0.428
2016	50	601	59.998	59.868	59.920	0.052	0.568	59.704	0.404

The following are observations from **Table E.2**:

- The mean Point C and Value B frequencies have both trended higher each year since 2012, suggesting improved overall primary frequency response in both the arresting and recovery phases.
- The mean Point C to UFLS margin has improved each year since 2012.
- For frequency events in the 2016 operating year, the lowest Point C frequency was above the first-step UFLS setting of 59.3 Hz by 404 mHz, which is a slightly larger margin than in 2015.

Table E.3: Frequency Event Statistics for Québec Interconnection

Operating Year	Total Number of Events [133]	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (Hz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (Hz)
2012	25	852	60.003	59.452	59.854	0.402	0.952	58.792	0.292
2013	35	973	59.996	59.395	59.825	0.430	0.895	58.868	0.368
2014	33	806	60.004	59.413	59.836	0.423	0.913	58.986	0.486
2015	29	627	60.003	59.555	59.872	0.292	1.055	59.273	0.773
2016	49	740	59.998	59.487	59.859	0.372	0.977	59.019	0.519

The following are observations from **Table E.3**:

- There is no clear trend in primary frequency response statistics due to loss of resources.

[131] The highest UFLS setpoint in the Eastern Interconnection is 59.7 Hz in FRCC, based on internal stability concerns. The FRCC concluded that the IFRO starting frequency of the prevalent 59.5 Hz for the Eastern Interconnection is acceptable in that it imposes no greater risk of UFLS operation in FRCC for an external resource loss event than for an internal FRCC event.

[132] One loss of load event was excluded from the ERCOT statistics in Table E.2 for the 2014 operating year.

[133] In the Quebec Interconnection, loss of load events were excluded from the statistics in Table E.3 for the following operating years: 2012 (6), 2013 (5), 2014 (9), 2015 (5), and 2016 (18).

- For frequency events in the 2016 operating year, the lowest Point C frequency was above the first-step UFLS setting of 58.5 Hz by 519 mHz, which is a smaller margin than in 2015 but larger than all other years above.

Table E.4: Frequency Event Statistics for Western Interconnection									
Operating Year	Number of Events	Mean Resource Loss (MW)	Mean Value A (Hz)	Mean Pt C (Hz)	Mean Value B (Hz)	Mean B-C Margin (Hz)	Mean Pt C-UFLS Margin (Hz)	Lowest Pt C (Hz)	Lowest Pt C-UFLS Margin (Hz)
2012	5	1016	60.010	59.906	59.939	0.033	0.406	59.880	0.380
2013	13	945	59.993	59.887	59.924	0.037	0.387	59.843	0.343
2014	17	1095	60.001	59.880	59.917	0.036	0.380	59.671	0.171
2015	21	846	59.998	59.903	59.934	0.032	0.403	59.845	0.345
2016	47	734	60.008	59.918	59.956	0.037	0.418	59.819	0.319

The following are observations from Table E.4:

- Point C and Value B frequencies have both trended higher since 2014, which could suggest improved overall primary frequency response in both the arresting and recovery phases. This trend should be monitored in light of a declining mean resource loss in those years.
- For frequency events in the 2016 operating year, the lowest Point C frequency was above the first-step UFLS setting of 59.5 Hz by 319 mHz, which is a smaller margin than in 2015 but larger than the lowest margin of 171 mHz in 2014.

Interconnection Frequency Response: Time Trends

The time trend analyses uses the interconnection FR datasets for the 2012–2016 operating years. In this section, relationships between FR and the explanatory variable T (time = year, month, day, hour, minute, second) are studied. **Figures E.4** through **Figure E.7** show the interconnection FR scatter plots with a linear regression trend line, the 95 percent confidence interval for the data, and the 95 percent confidence interval for the slope of the time trend line.

It is important to note that there is a difference between the measured frequency response for a given event and the amount of response that was actually available at the time of the event. Measured response varies depending on starting frequency as well as the size of the resource loss.

Eastern Interconnection

In the Eastern Interconnection, there is a positive correlation of 0.12 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p value of both tests is 0.10). This result leads to the inference that the positive correlation may have occurred simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR, shown in **Figure E.4**, has a positive slope (0.00000184), the slope of the linear regression is not statistically significant, and on average, the Eastern Interconnection FR trend has been stable from 2012–2016.

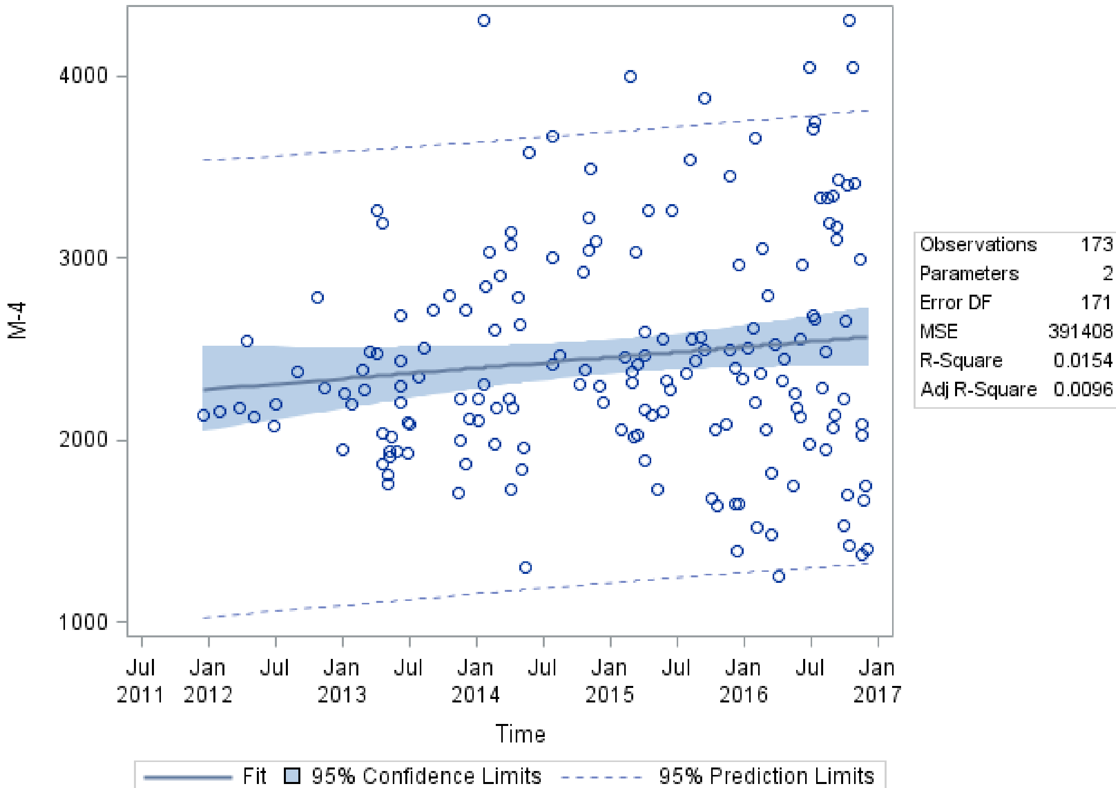

Figure E.4: Eastern Interconnection FR Scatter Plot and Time Trend Line 2012–2016

ERCOT Interconnection

In the ERCOT Interconnection, there is a positive correlation of 0.32 between T and FR; further, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) results in a rejection of the null hypothesis about zero correlation at a standard significance level (p-value of both tests is below 0.0001). This proves that it was very unlikely that the observed positive correlation occurred simply by chance. A linear trend line for the scatter plot connecting T and FR (shown in **Figure E.5**) has a positive slope (0.00000163), and the linear regression slope is highly statistically significant. On average, the ERCOT interconnection FR grew from 2012 to 2016 at the monthly rate of 4.25 MW/0.1 Hz.

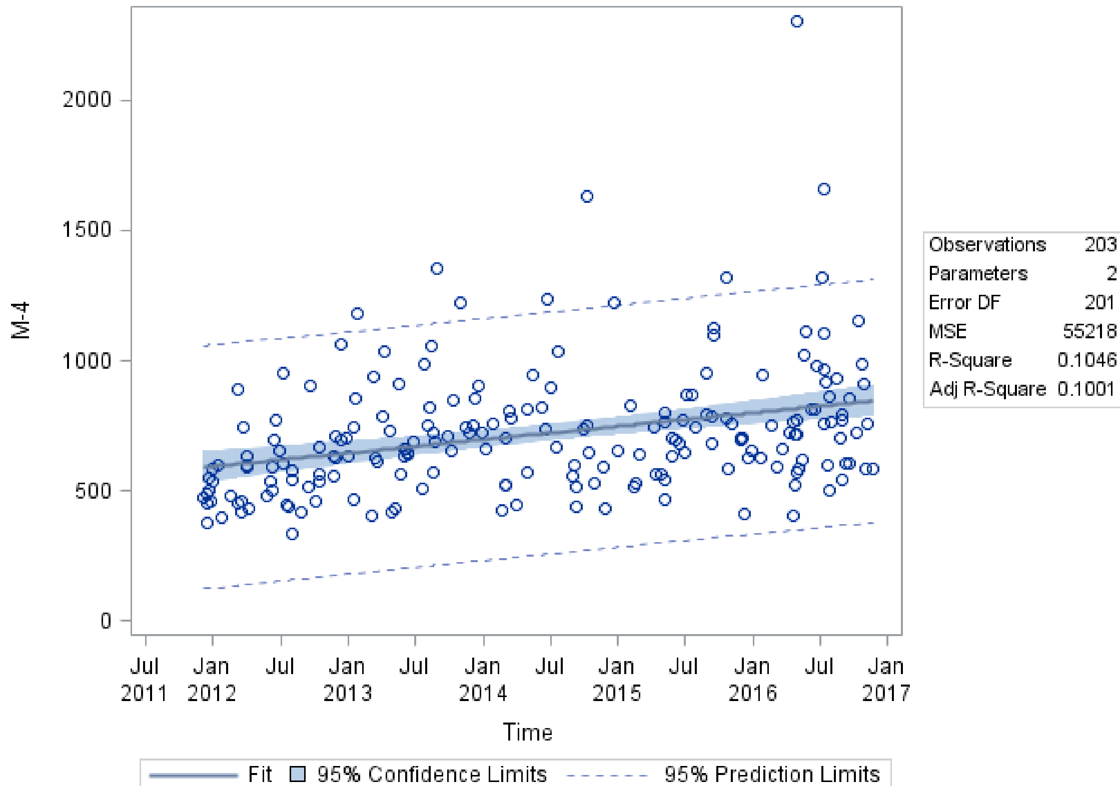

Figure E.5: ERCOT Interconnection Frequency Response Scatter Plot and Time Trend Line 2012–2016

Québec Interconnection

In the Québec Interconnection, there is a negative correlation of -0.12 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p value of both tests is 0.10). This result leads to the conclusion that the negative correlation very likely has occurred simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR, shown in **Figure E.6**, has a negative slope (-0.000000621), the linear regression is not statistically significant, and, on average, the Québec Interconnection FR has been flat from 2012 to 2016.

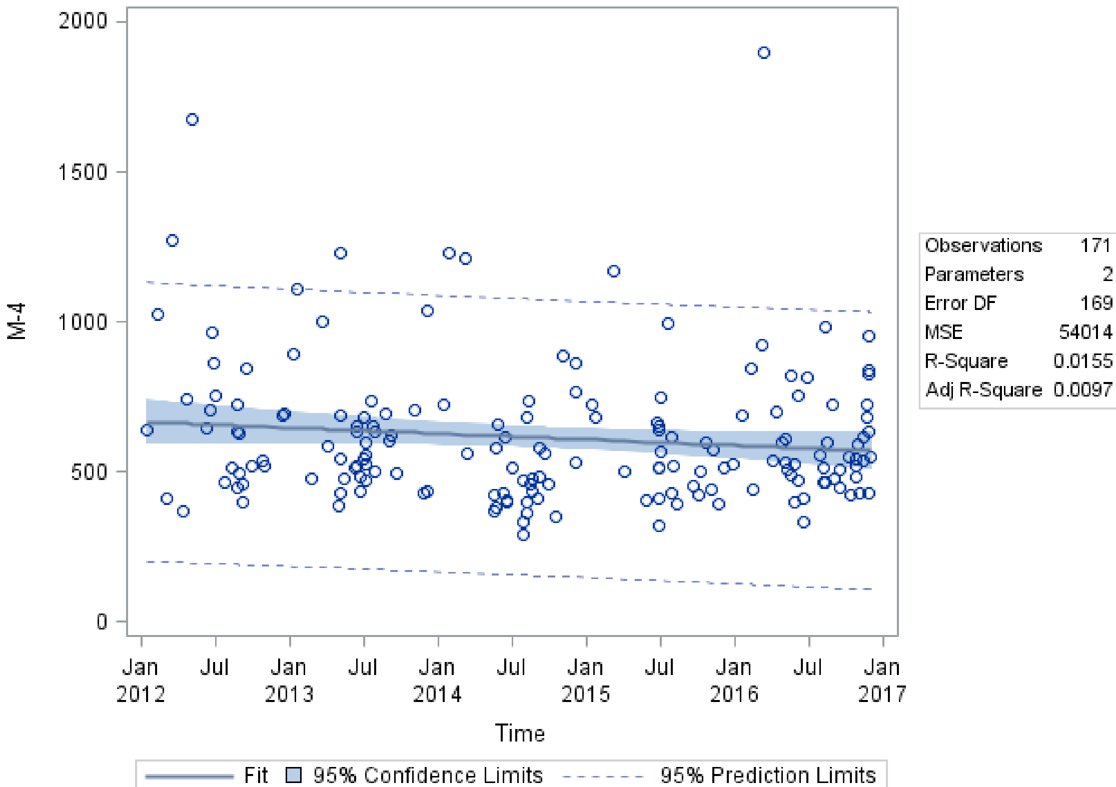

Figure E.6: Québec Interconnection Frequency Response Scatter Plot and Time Trend Line 20122016

Western Interconnection

In the Western Interconnection, there is a positive correlation of 0.12 between T and FR; however, the statistical test on the significance of the correlation (and the equivalent test of the significance of a linear regression) fails to reject the null hypothesis about zero correlation at a standard significance level (p value of both tests is 0.21). This result leads to the conclusion that the positive correlation very likely have occurred simply by chance. It implies that even though a linear trend line for the scatter plot connecting T and FR, shown in **Figure E.7**, has a positive slope (0.00000151), the slope of the linear regression is not statistically significant, and on average, the Western Interconnection FR trend has been stable from 2012–2016.

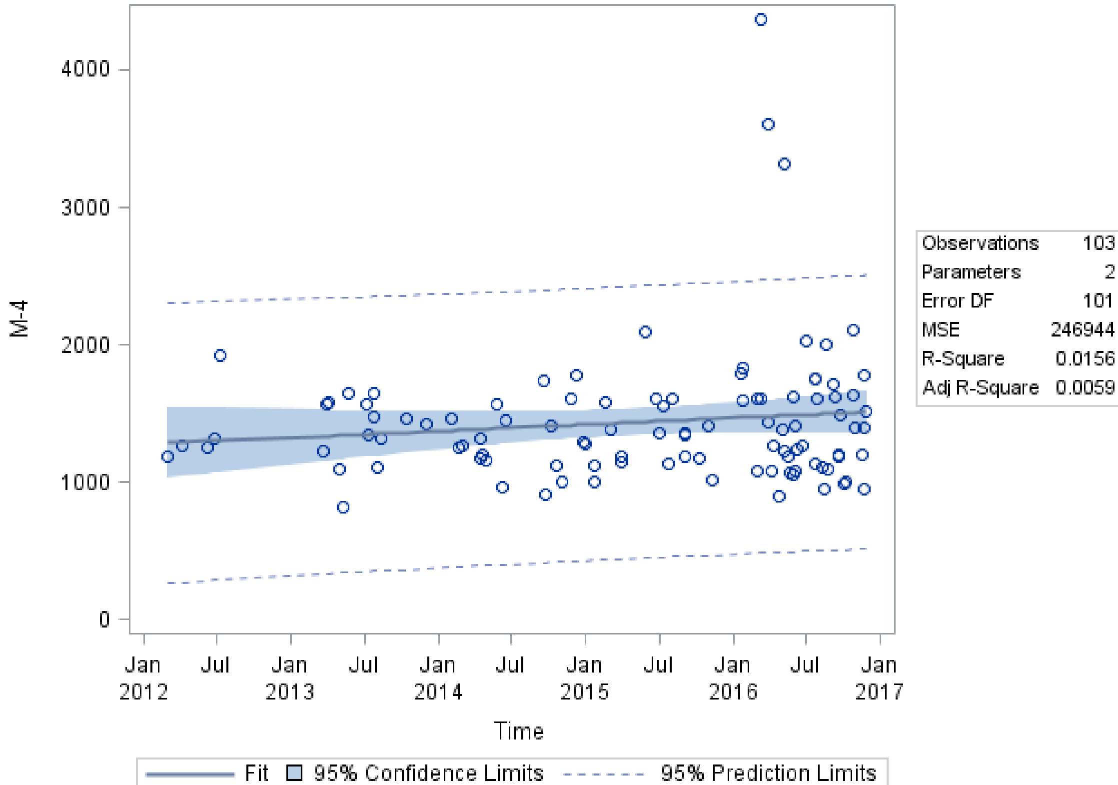

Figure E.7: Western Interconnection Frequency Response Scatter Plot and Time Trend Line 2012–2016

Interconnection Frequency Response: Year-to-Year Changes

The analyses of changes by year use the interconnection FR datasets from the 2012–2016 operating years. The sample statistics are listed by year in Tables E.5 through E.8. The last column lists the number of FR events that fell below the absolute IFRO.[134]

Figures E.8 through **Figure E.11** show the box and whisker plots of the annual distribution of the interconnection's FR. The boxes enclose the interquartile range with the lower edge at the first (lower) quartile and the upper edge at the third (upper) quartile. The horizontal line drawn through a box is the second quartile or the median. The lower whisker is a line from the first quartile to the smallest data point within 1.5 interquartile ranges from the first quartile. The upper whisker is a line from the third quartile to the largest data point within 1.5 interquartile ranges from the third quartile. The data points beyond the whiskers represent outliers, or data points more than or less than 1.5 times the upper and lower quartiles, respectively. The diamonds represent the mean.

Next, to statistically compare parameters of the annual distributions of the frequency response listed in Tables E.5 to E.8, ANOVA's Fisher's Least Significant Difference test and t-test were used to analyze all pair-wise changes in the mean FR, the Mann-Whitney and Wilcoxon test was used to compare annual medians, and the tests on the homogeneity of variances to analyze changes in variance (and, thus, in the standard deviation).[135]

In the 2016 operating year, a change in selection criteria was implemented that included frequency events with a smaller MW loss if the event resulted in a sufficient frequency deviation. Note that this change resulted in a larger sample of events for all interconnections as compared to previous years.

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[134] http://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf

[135] All tests at the significance level 0.05.

Eastern Interconnection

Table E.5 and Figure E.8 illustrate Eastern Interconnection year-to year changes in the average and median FR as well as in its variation. There were no frequency events with FR below IFRO in 2012–2016.

Table E.5: Sample Statistics for Eastern Interconnection								
Operating Year (OY)	Number of Events	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	IFRO for the OY	Number of Events with FR Below the IFRO
2012–2016	**173**	**2,456.7**	**628.7**	**2,329.8**	**1,253.2**	**4,307.4**	**N/A**	**0**
2012	10	2,288.3	222.7	2,187.5	2,081.5	2,783.5	1002	0
2013	32	2,239.1	384.1	2,200.7	1,707.0	3,264.4	1002	0
2014	34	2,639.7	626.9	2,619.7	1,300.3	4,304.1	1014	0
2015	36	2,479.9	577.1	2,372.0	1,635.8	3,996.9	1014	0
2016	61	2,482.9	767.4	2,368.6	1,253.2	4,307.4	1015	0

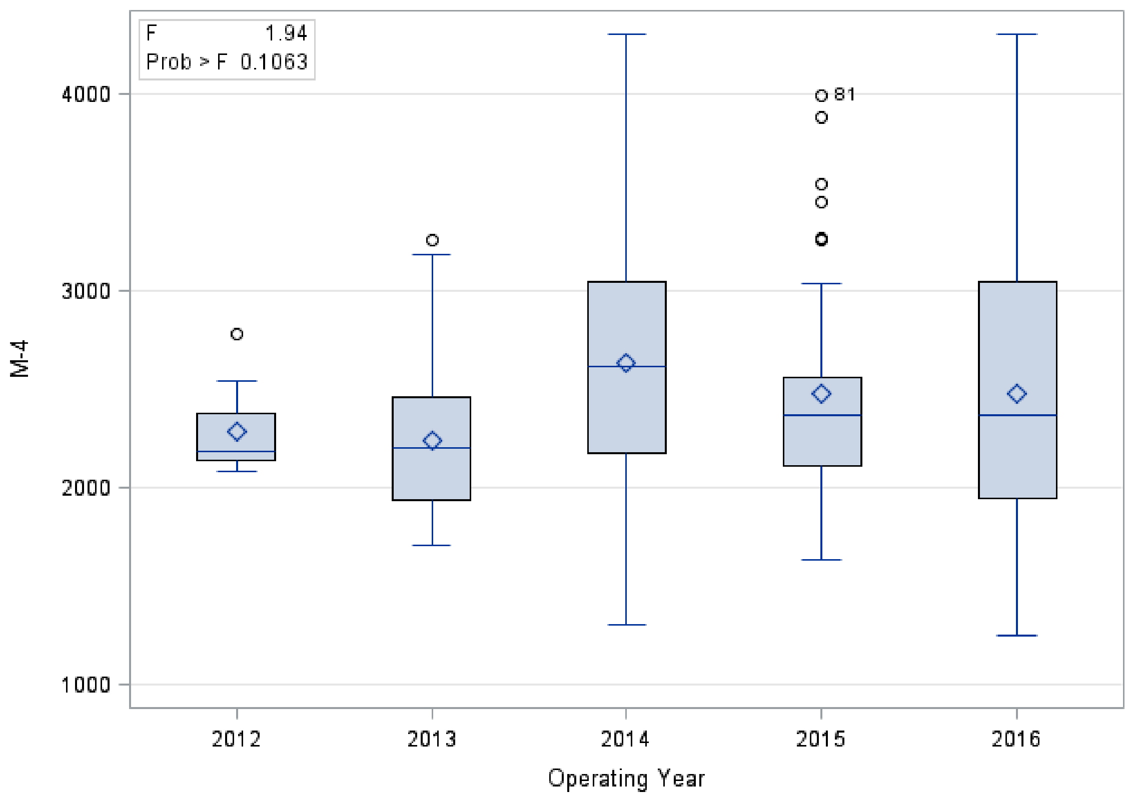

Figure E.8: Eastern Interconnection Frequency Response Distribution by Operating Year 2012–2016

There was a statistically significant increase in both the mean frequency response and the variance of frequency response in 2014 vs. 2013 and in 2016 vs. 2013 operating years; the 2014 median statistically significantly increased compared with 2013 and has not changed statistically after that (a very small number of events in the 2012 operating year does not allow for a reliable statistical comparison with other years). For the 2016 operating year, frequency events with the minimum frequency response of 1253 MW/0.1Hz were 23.4 percent above the IFRO with the event resulting in a C point frequency within 460 mHz of the interconnection first step UFLS setting from a starting frequency of 60.008 Hz.

ERCOT Interconnection

Table E.6 and **Figure E.9** illustrate year-to year changes in the average and median FR as well as in its variation. Over the five years, there was one frequency event with FR below IFRO (in 2015).

Table E.6: Sample Statistics for ERCOT Interconnection

Operating Year (OY)	Number of Events	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	IFRO for the OY	Number of Events with FR Below the IFRO
2012–2016	**203**	**719.0**	**247.7**	**688.7**	**336.7**	**2,304.4**	**N/A**	**1**
2012	46	561.6	135.6	540.8	336.7	948.6	286	0
2013	40	752.2	218.2	704.9	406.6	1,353.9	286	0
2014	33	727.2	245.9	720.2	425.7	1,628.0	413	0
2015	34	755.8	196.7	722.1	468.6	1,315.8	471	1
2016	50	806.7	315.7	752.0	403.6	2,304.4	381	0

Figure E.9 shows the box plot of the annual distribution of the ERCOT FR.

The mean and the median FR in the 2013, 2014, 2015 and 2016 operating years were significantly better than in the 2012. Numerically, the mean and the median FR in 2016 were the highest over the five years in the study, but the variance also statistically significantly increased compared with 2015. These results corroborate an observation on the improving frequency response trend in ERCOT. For 2016 operating year frequency events had the lowest frequency response of 404 MW/0.1Hz, which was 6.0 percent above the IFRO with the event resulting in a C point frequency nadir within 605 mHz of the interconnection first step UFLS setting from a starting frequency of 60.015 Hz.

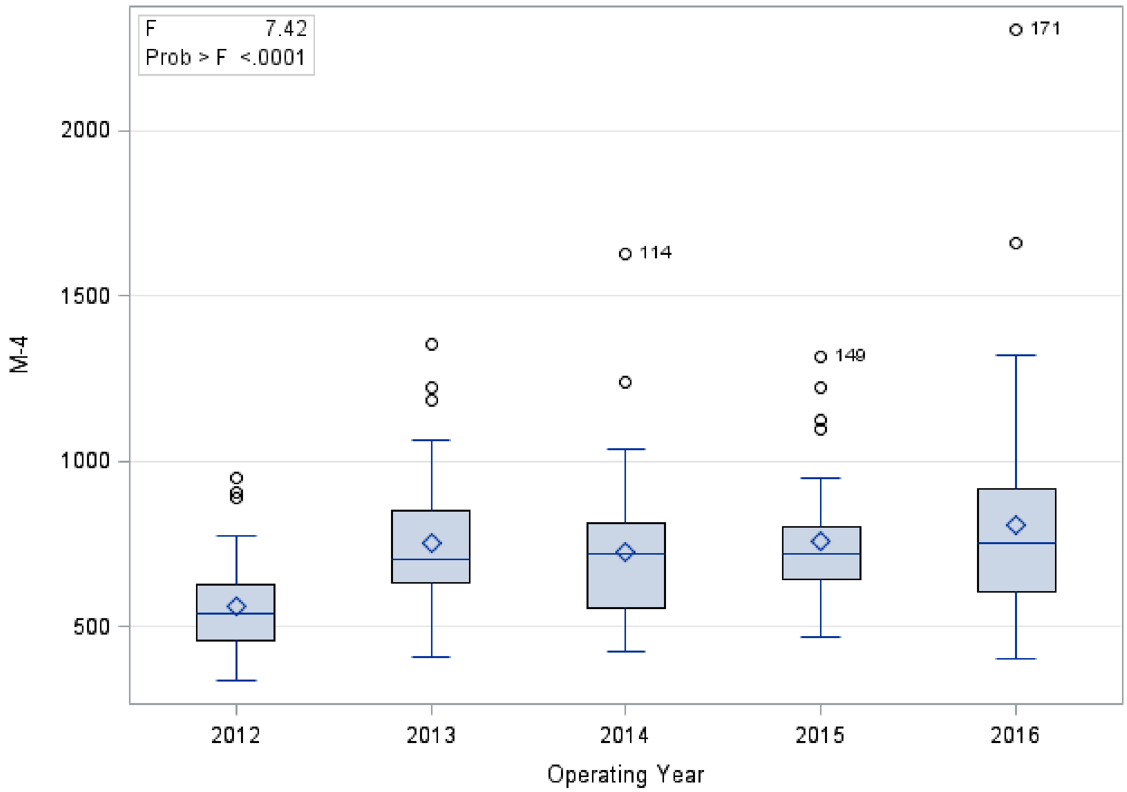

Figure E.9: ERCOT Frequency Response Distribution by Operating Year 2012–2015

Québec Interconnection

Table E.7 and **Figure E.10** illustrate year-to year changes in the average and median FR as well as in its variation. There were no frequency events with FR below IFRO in 2012–2016.

Table E.7: Sample Statistics for Quebec Interconnection

Operating Year (OY)	Number of Events	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	IFRO for the OY	Number of Events with FR Below the IFRO
2012–2016	**171**	**612.9**	**233.5**	**545.9**	**288.3**	**1900.0**	**N/A**	**0**
2012	25	689.8	299.1	635.0	370.8	1673.6	179	0
2013	35	624.1	187.5	596.3	389.1	1227.8	179	0
2014	33	555.5	236.0	468.8	288.3	1230.6	180	0
2015	29	586.2	190.1	531.8	320.1	1167.4	183	0
2016	49	620.0	243.7	543.8	334.5	1900.0	179	0

Figure E.10 shows the box plot of the annual distribution of the Québec Interconnection FR.

Fisher's Least Significant Difference test found only one statistically significant change in the mean FR; a decrease in 2014 vs. 2012. In the 2015 and 2016 operating years the mean FR consistently but not significantly increased. The Wilcoxon test showed that after the lowest median value in 2014, the 2015 and 2016 medians consistently increased with the 2016 being statistically significantly greater than in 2014. Finally, tests for homogeneity of variance detected a statistically significant increase in the 2016 variance compared with 2015. For 2016 M4 frequency events the lowest frequency response of 334 MW/0.1Hz occurred during a loss-of-load event and was 86.6 percent above the IFRO with the event resulting in a C point frequency of 60.510 Hz from a starting frequency of 59.975 Hz.

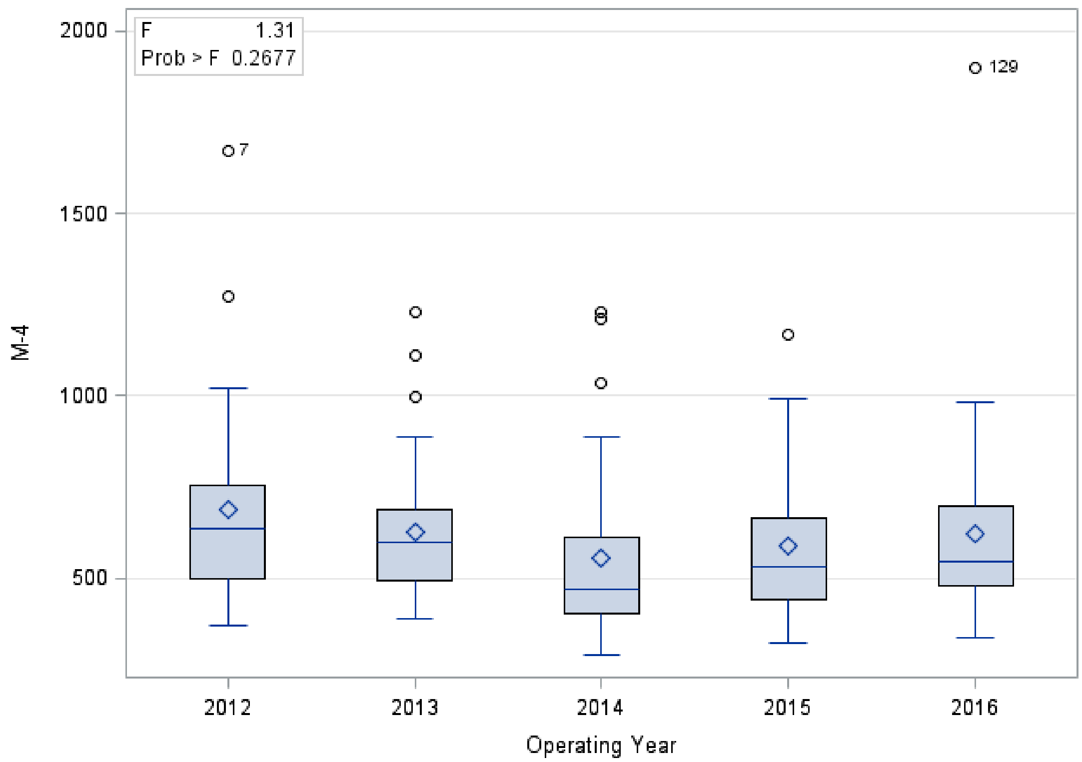

Figure E.10: Québec Interconnection Frequency Response Distribution by Operating Year 2012–2016

Western Interconnection

Table E.8 lists the average and median FR as well as in its variation. Over the five years, there were two frequency events with FR below IFRO (2013 and 2014).

Table E.8: Sample Statistics for Western Interconnection

Operating Year (OY)	Number of Events	Mean of Frequency Response	Standard Dev. of Frequency Response	Median	Minimum	Maximum	IFRO for the OY	Number of Events with FR Below the IFRO
2012–2016	**103**	**1,436.7**	**498.4**	**1,349.8**	**821.9**	**4,368.4**	**N/A**	**2**
2012	5	1,692.2	978.1	1,267.0	1,184.1	3,439.7	840	0
2013	13	1,373.6	251.0	1,463.1	821.9	1,645.0	840	1
2014	17	1,288.9	228.1	1,265.6	905.0	1,743.2	949	1
2015	21	1,360.7	269.4	1,348.5	1,007.6	2,098.8	906	0
2016	47	1,544.6	672.7	1,400.0	901.7	4,368.4	858	0

Figure E.11 shows the box plot of the annual distribution of the Western Interconnection FR. The lowest 2016 IFRM of 902 MW/0.1 Hz occurred for an event at approximately 2:15 a.m. in April. Frequency responsive resource dispatch was low during this light load period.

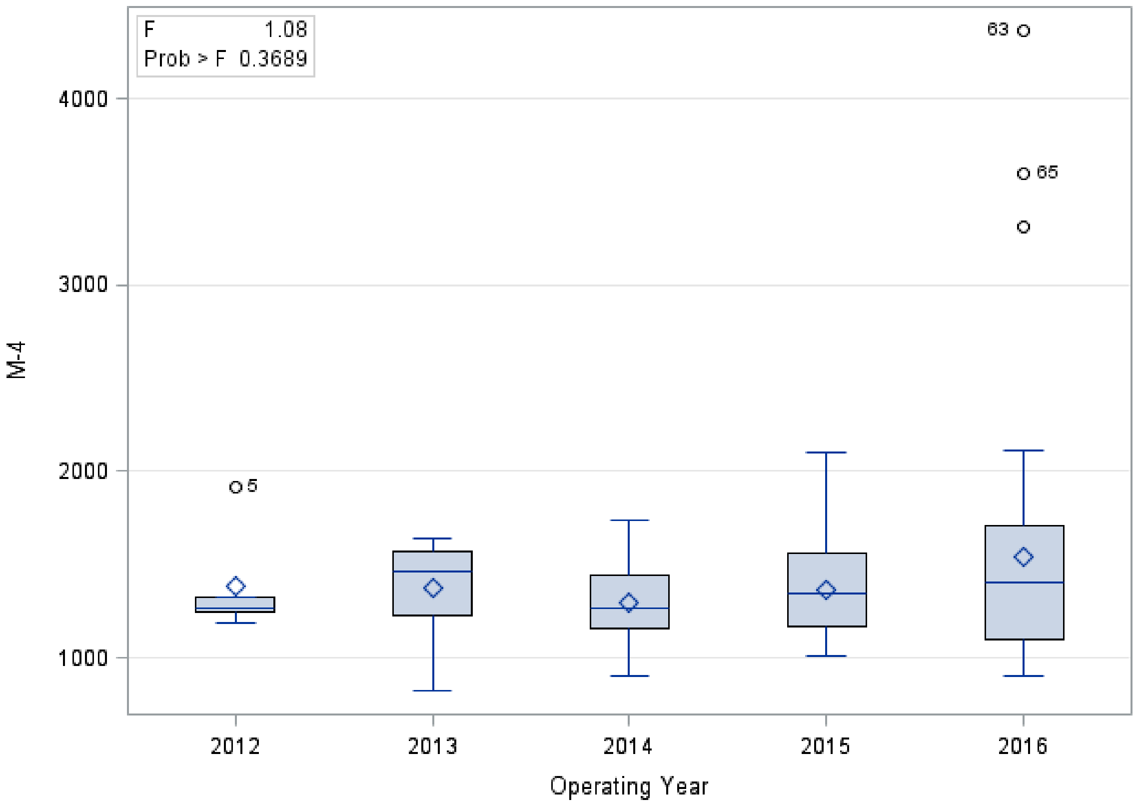

Figure E.11: Western Interconnection Frequency Response Distribution by Year 2012–2016

There was a statistically significant increase in the expected FR in 2016 versus 2014. The 2016 median FR was numerically higher than in 2014 and 2015. However, the 2016 variance also statistically significantly increased compared with both 2014 and 2015 (the 2012 and 2013 data sets were too small for a valid statistical inference). For 2016 frequency events, the minimum frequency response of 902 MW/0.1Hz was 5.1 percent above the IFRO with the event, resulting in a C point frequency nadir within 438 mHz of the interconnection first step UFLS setting from a starting frequency of 60.037 Hz.

Interconnection Frequency Response: Analysis of Distribution

Eastern Interconnection

Figure E.12 shows the histogram of the Eastern Interconnection FR for the 2012–2016 operating years based on the 173 observations of M-4. This is a right-skewed distribution with the median of 2,329.8 MW/0.1 Hz, the mean of 2,456.7 MW/0.1 Hz, and the standard deviation of 628.7 MW/0.1 Hz.

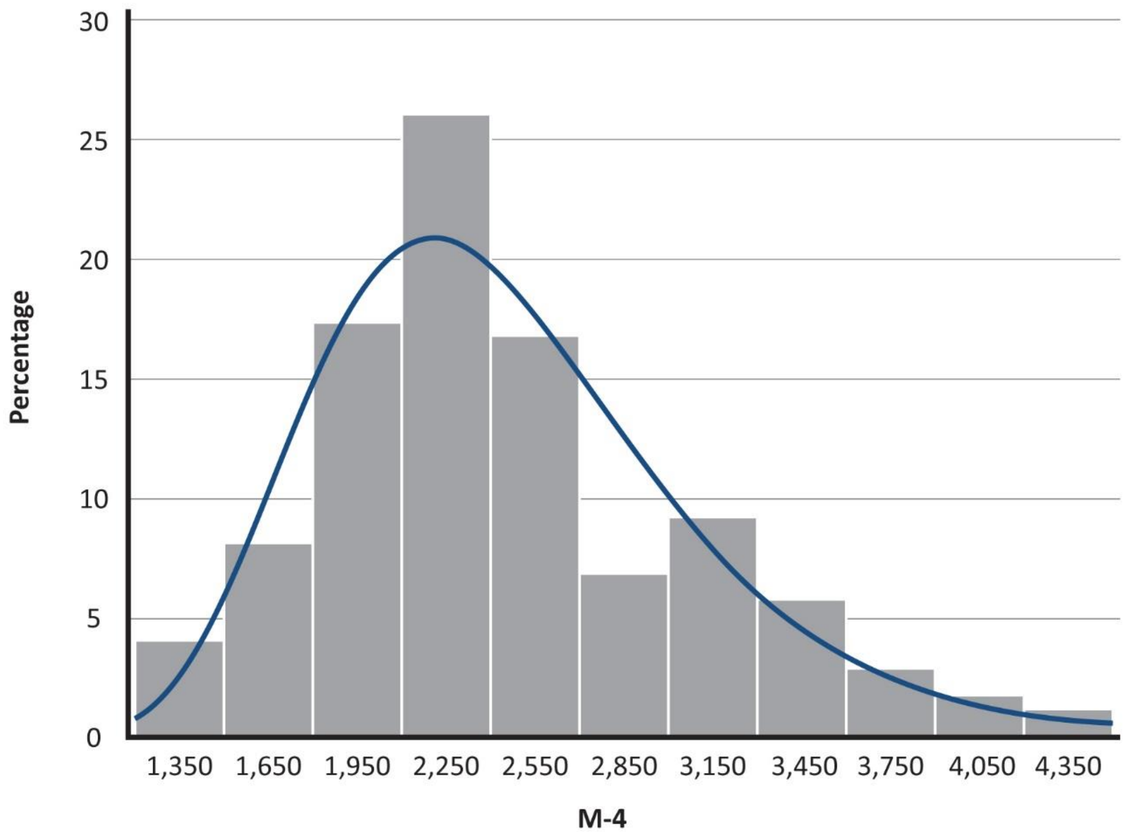

Figure E.12: Histogram of the Eastern Interconnection Frequency Response 2012–2016

Kolmogorov-Smirnov, Cramer-von Mises, and Anderson-Darling Goodness-of-Fit tests varied in conclusions: Kolmogorov-Smirnov and Anderson-Darling tests showed that a lognormal distribution can be an appropriate approximation for the five year Eastern Interconnection FR distribution (p-values of 0.13 and 0.06 point out to a not very good fit) while Cramer-von Mises test resulted in rejection of the null hypothesis on the lognormality of the distribution. No other table distribution fit the Eastern FR data.

The parameters of this lognormal distribution are as follows: the threshold = 672.0, the scale = 7.6, and the shape = 0.28. The probability density function of the fitted distribution is shown in **Figure E.12** as a green curve.

ERCOT Interconnection

Figure E.13 shows the histogram of the ERCOT Interconnection FR for the 2012–2016 operating years based on the 203 observations of M-4. This is a right-skewed distribution with the median of 688.73 MW/0.1 Hz, the mean of 718.95 MW/0.1 Hz and the standard deviation of 247.72 MW/0.1 Hz.

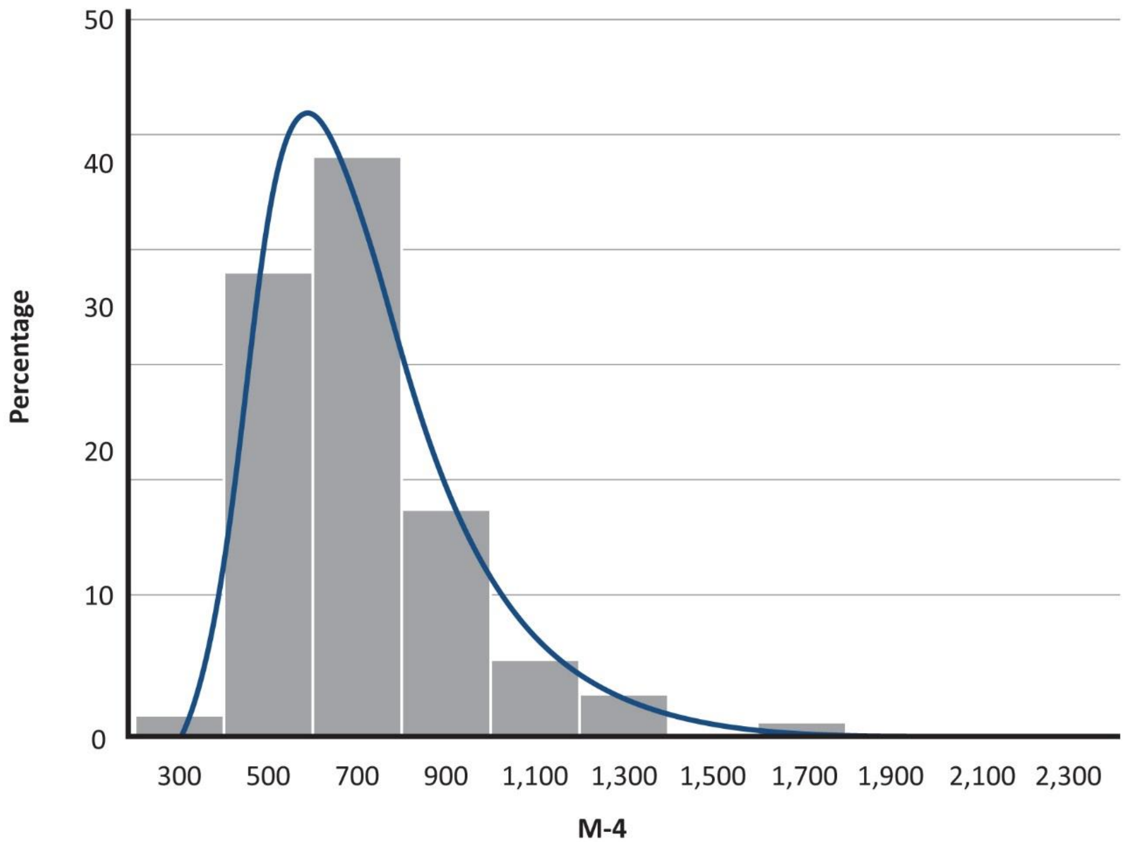

Figure E.13: Histogram of the ERCOT Interconnection Frequency Response 2012–2016

The Kolmogorov-Smirnov, Cramer-von Mises, and Anderson-Darling Goodness-of-Fit tests showed that a lognormal distribution can be a good approximation for the ERCOT FR distribution for the four years (p-values are greater than 0.25, 0.13 and 0.17, respectively). The parameters of this lognormal distribution are as follows: the threshold = 225.6, the scale = 6.1, and the shape = 0.46. The probability density function of the fitted distribution is shown in **Figure E.13** as a green curve.

Québec Interconnection

Figure E.14 shows the histogram of the Québec Interconnection FR for the 2012–2016 operating years based on the 171 observations of M-4. This is a right-skewed distribution with the median of 545.9 MW/0.1 Hz, the mean of 612.9 MW/0.1 Hz, and the standard deviation of 233.5 MW/0.1 Hz.

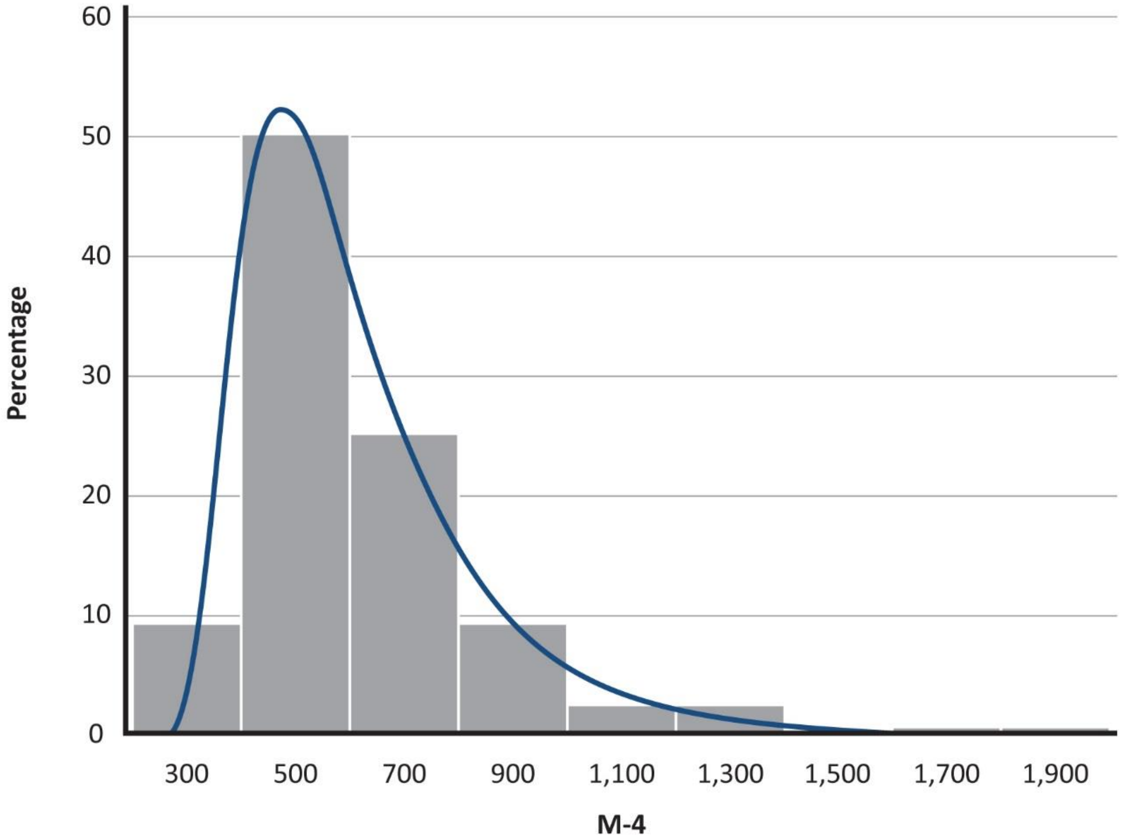

Figure E.14: Histogram of the Québec Interconnection Frequency Response 2012–2016

Kolmogorov-Smirnov, Cramer-von Mises, and Anderson-Darling Goodness-of-Fit tests showed that a lognormal distribution can be a good approximation for the Québec Interconnection FR distribution for the five years (all p-values are greater than 0.25). The parameters of this lognormal distribution are as follows: the threshold = 235.2, the scale = 5.8, and the shape = 0.55. The probability density function of the fitted distribution is shown in **Figure E.14** as a green curve.

Western Interconnection

Figure E.15 shows the histogram of the Western Interconnection FR for the 2012–2016 operating years based on the 103 observations of M-4. This is a right-skewed distribution with the median of 1349.8 MW/0.1 Hz, the mean of 1436.7 MW/0.1 Hz, and the standard deviation of 498.4 MW/0.1 Hz.

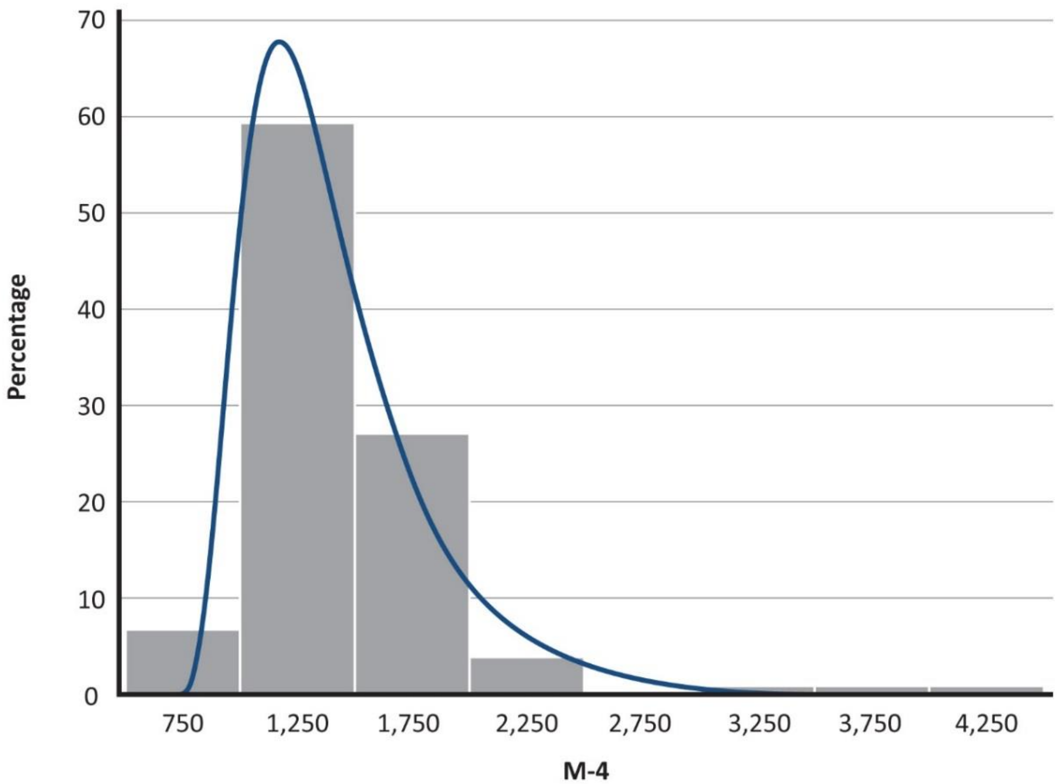

Figure E.15: Histogram of the Western Interconnection Frequency Response 2012–2016

Kolmogorov-Smirnov, Cramer-von Mises, and Anderson-Darling Goodness-of-Fit tests varied in conclusions: the first two tests showed that a lognormal distribution can be an appropriate approximation for the five-year Western Interconnection FR distribution (p-values of 0.12 and 0.19 point out to a not very good fit, partly due to the three 2016 upper outliers as seen in Figure E.11) while Anderson-Darling test resulted in rejection of the null hypothesis on the lognormality of the distribution (p-value=0.06). No other table distribution fit the Western FR data.

The parameters of the lognormal distribution are as follows: the threshold = 699.8, the scale = 6.5, and the shape = 0.54. The probability density function of the fitted lognormal distribution is shown in **Figure E.15** as a green curve.

Explanatory Variables for Frequency Response and Multiple Regression

Explanatory Variables

In the 2013–2016 *State of Reliability* reports, NERC staff evaluated how specific indicators could be tied to severity of frequency deviation events. In 2016, a set of explanatory variables that might affect the interconnection FR has been extended to 10 variables. This year, the renewable generation is added by source for all interconnections except the Eastern Interconnection. The selected variables are neither exhaustive nor pair-wise uncorrelated, and some pairs are strongly correlated; however, all are included as candidates to avoid the loss of an important contributor to the FR variability. First, the frequency response and explanatory variables are tested for a significant correlation (positive or negative); if a significant correlation is found, numerical estimates are provided of the explanatory variable impact to the FR. Then a multiple (i.e., multivariate) regression model, describing the frequency response with these explanatory variables as regressors, is built for each interconnection. Model selection methods help ensure the removal of highly correlated regressors and run multicollinearity diagnostics

(variance inflation diagnostics) for a multiple regression model selected. The explanatory variables included in this study are as follows:
Time: A moment in time (year, month, day, hour, minute, second) when an FR event happened. Time is measured in seconds elapsed between midnight of January 1, 1960 (the time origin for the date format in SAS), and the time of a corresponding FR event. This is used to determine trends over the study period.

Winter (Indicator Function): Defined as one for FR events that occur from December through February, and zero otherwise.

Spring (Indicator Function): Defined as one for FR events that occur from March through May, and zero otherwise.
Summer (Indicator Function): Defined as one for FR events that occur from June through August, and zero otherwise.

Fall (Indicator Function): Defined as one for FR events that occur from September through November, and zero otherwise.

On-peak Hours (Indicator Function) Defined as one for FR events that occurred during on-peak hours, and zero otherwise. On-peak hours are designated as follows: Monday to Saturday from 0700–2200 (Central Time) excluding six holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Predisturbance Frequency A: Value A as shown in Figure E.3 (measured in Hz).

Margin = C-UFLS: Difference between an event nadir, Point C, as shown in Figure E.3 and the UFLS for a given interconnection. Measured in Hz. The UFLS values are listed in **Table E.9**.

Table E.9: Underfrequency Load Shed

Interconnection	Highest UFLS Trip Frequency
Eastern	59.5 Hz
ERCOT	59.3 Hz
Québec	58.5 Hz
Western	59.5 Hz

Interconnection Load Level: Measured in megawatts.

Interconnection Load Change by Hour: Difference between interconnection load at the end of the hour and at the beginning of the hour during which the frequency event occurred. Measured in megawatts.

Renewable Generation by Type: ERCOT provided the 2012–2016 hourly data for wind generation load. Note that wind is the only significant renewable source in ERCOT with the average hourly generation of about 4600 MW in 2015 (for comparison, solar generation is still less than 200 MW total installed capacity and hydroelectric generation is even smaller).

The Québec Interconnection provided the 2013–2016 hourly data for wind generation load.

WECC provided the 2013–2015 hourly data for renewable generation load level in the WI by generation type (Hydro, Wind, and Solar).

Data Sets: Some datasets (Interconnection load for the EI and the WI, Wind Load for ERCOT and the WI, Hydro and Solar loads) are not available for the five-year range for the 2012–2016 operating years. In such cases, the correlation between FR and this explanatory variable is calculated based on the available data. Even complete five-year data sets have insufficient sizes for a good explanatory and predictive model, which requires estimates of big number of parameters. An adequate model for each interconnection can only come with an annual increase of the FR data sets.

Summary of Correlation Analysis

For each interconnection, results of the correlation and a single regression analysis are shown in Table E.12, Table E.15, Table E.18 and Table E.21 and explained in details in the respective sections below. The explanatory variables are ranked from highest Pearson's coefficient of determination to the smallest; the coefficient indicates the explanatory power of an explanatory variable for the frequency response. Summary **Table E.10** lists the ranks of statistically significant[136] variables for frequency response in each interconnection. In **Table E.10**, the "Positive" indicates a statistically significant positive correlation, "Negative" indicates a statistically significant negative correlation, and a dash indicates no statistically significant linear relation.

Table E.10: Observation Summary

Explanatory Variable	Eastern	ERCOT	Québec	Western
Time	-	2 (positive)	-	-
Winter	-	6 (negative)	3 (positive)	-
Spring	3 (negative)	-	4 (positive)	4 (positive)
Summer	4 (positive)	5 (positive)	5 (negative)	-
Fall	-	-	7 (negative)	-
Predisturbance Frequency A (Hz)	1 (negative)	1 (negative)	6 (negative)	2 (negative)
Margin = C-UFLS (Hz)	2 (negative)	-	2 (positive)	-
On-Peak Hours	-	-	-	-
Interconnection Load	-	4 (positive)	1 (positive)	1 (positive)
Interconnection Load Change by Hour	-	-	-	-
Wind Load	No data	3 (positive)	-	-
Hydro Load	No data	No data	No data	3 (positive)
Solar Load	No data	No data	No data	-

A statistically significant positive correlation between time and FR confirms an increasing trend for FR in the ERCOT Interconnection. Predisturbance Frequency has a statistically significant impact to FR in all the interconnections—the higher A the lower FR. Low frequency events with a starting frequency above 60 Hz (Value A) tend to have smaller FR since it is less likely that frequency will drop below the governor deadband setting. Interconnection load is significantly and positively correlated with FR in all interconnections except the EI. Among interconnections with renewable generation data available, Hydro load in the WI and Wind load in ERC0T positively and statistically significantly affect the respective FR.

[136] At the significance level 0.1.

For each interconnection there is found at least one season with statistically different expected FR than the other seasons combined. Winter events have on average smaller FR than other seasons in ERCOT but greater FR than other seasons in Québec. Spring events have on average smaller FR than other seasons in the EI but greater FR than other seasons in the Québec Interconnection (QI) and the WI. Summer events have on average smaller FR than other seasons in the QI but greater FR than other seasons in the EI and ERCOT. Finally, fall events have on average smaller FR than other seasons in the QI.

Margin = C-UFLS is statistically significantly correlated with FR in the EI and the QI; however, in the QI the correlation is positive (the higher Margin the higher FR) while in the EI the correlation is negative.

Other observations from the comparative analysis by interconnection are as follows:

- As expected with larger datasets, the statistical significance of the results and the explanatory power of regressors improve. However, to build good explanatory and predictive models of frequency response with multiple explanatory variables, more years of data and possibly additional variables are needed.
- The majority of the events occurs during on-peak hours, ranging from 57 percent in the WI to 66 percent in the QI.
- In the EI, 44 percent of events start with Predisturbance Frequency A<60 Hz while the other interconnections majority of events start with A>60 Hz (54 percent in ERCOT and the QI, and 57 percent in the WI).
- In the QI, more events occur when the Interconnection load level decreases, and more events occur in the other interconnections when the load level increases.

More details on the correlation analysis and multivariate models by Interconnection are provided in the following information.

Eastern Interconnection: Correlation Analysis and Multivariate Model

Descriptive statistics for the 10 explanatory variables and the Eastern Interconnection FR are listed in Table E.11.

Table E.11: Descriptive Statistics: Eastern Interconnection

Variable	N	Mean	Standard Dev.	Median	Minimum	Maximum
Time	173				12/1/2011	11/30/2016
Winter	173	0.21	0.41	0	0	1
Spring	173	0.32	0.47	0	0	1
Summer	173	0.21	0.41	0	0	1
Fall	173	0.25	0.44	0	0	1
Predisturbance Frequency A (Hz)	173	60.00	0.01	60.00	59.97	60.03
Margin = C-UFLS (Hz)	173	0.45	0.01	0.45	0.41	0.49
On-Peak Hours	173	0.65	0.48	1	0	1
Interconnection Load (MW)	118	341,334	58,385	333,204	229,029	496,521
Load Change by Hour (MW)	118	402	10,366	441	-32019	28,611
Frequency Response	173	2,457	629	2,330	1,253	4,307

Interconnection load and interconnection load change by hour data are available for the 118 FR events that occurred from 2012–2015 calendar years. Other data are available for all 173 events.

The correlation and a single regression analysis result in the hierarchy of the explanatory variables for the Eastern Interconnection FR as shown in **Table E.12**. The table lists p-values of the test on the significance of correlation between each explanatory variable and FR. If p-value is smaller than 0.1, the correlation is statistically significant at the 0.1 significance level. For such a variable, the value of a coefficient of determination R^2 in the last column indicates the percentage in variability of the FR data that can be explained by variability of this explanatory variable.

Table E.12: Correlation and Regression Analysis: Eastern Interconnection

Explanatory Variable	Correlation with FR	P-value	R^2 If Statistically Significant[137]
Predisturbance Frequency A (Hz)	-0.55	<.0001	30.7%
Margin = C-UFLS (Hz)	-0.35	<.0001	12.2%
Spring	-0.19	0.013	3.6%
Summer	0.18	0.016	3.3%
Time	0.12	0.104	N/A
Load Change by Hour (MW)	0.08	0.380	N/A
Interconnection Load (MW)	0.08	0.399	N/A
Fall	0.06	0.423	N/A
On-Peak Hours	-0.05	0.497	N/A
Winter	-0.03	0.673	N/A

Out of the 10 explanatory variables, four have a statistically significant correlation with the Eastern Interconnection FR. Predisturbance Frequency A has the strongest correlation with and the greatest explanatory power (30.7 percent) for the FR. Predisturbance Frequency and Margin are negatively correlated with FR. Thus, events with higher A have smaller expected FR: on average, the EI frequency response decreases by 309.3 MW/0.1 Hz as A increases by 10 mHz. Similarly, events with larger Margin (and therefore higher nadir C) have statistically significantly smaller expected FR: on average, FR decreases by 189.1 MW/0.1 Hz as Margin increases by 10 mHz. Note that A and Margin are not independent variables: there is a statistically significant positive correlation of 0.70 between them (p-value of the test of the significance of correlation <0.0001).

Next, Indicator of spring has a significant negative correlation with FR, which means that on average spring events have a statistically significantly smaller FR than the other seasons (2283 MW/0.1 Hz versus 2538 MW/0.1 Hz); they also have a larger variability (FR variance). Finally, summer has a significant positive correlation with FR, which means that on average summer events have a statistically significantly higher FR than the other seasons (2676 MW/0.1 Hz versus 2397 MW/0.1 Hz); their variance is similar to events for the other seasons. The remaining six variables do not have a statistically significant linear relationship with FR.

Since both Interconnection load and Load Change by Hour are not significantly correlated with FR, these two variables are excluded from the multiple regression model to keep the sample size relatively large (173 observations versus 118). The step-wise selection and backward elimination algorithms result in a multiple

[137] At the significance level 0.1

regression model that connects the 2012–2016 Eastern Interconnection FR with Predisturbance Frequency A and spring (the other variables are not selected or were eliminated by the algorithms).[138] The model's coefficients are listed in **Table E.13**.

Table E.13: Coefficients of Multiple Model: Eastern Interconnection						
Variable	**DF**	**Parameter Estimate**	**Standard Error**	**t-value**	**p-value**	**Variance Inflation Value**
Intercept	1	1877785	207283	9.06	<.0001	0.00
Spring	1	-276.9	83.3	-3.32	0.0011	1.000082
Predisturbance Frequency A (Hz)	1	-31255	3455	-9.05	<.0001	1.000082

The adjusted coefficient of the determination adj R^2 of the model is 34.2 percent; the model is highly statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 510 MW/0.1 Hz. Variance inflation factors for the regressors are very close to 1, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model. The parameter estimates, or the coefficients for the regressors, indicate how change in a regressor value impacts FR. Note that the regressors in the final model are not correlated: t-test confirms that the spring events and the other seasons combined have statistically similar expected A and the variance of A.

ERCOT: Correlation Analysis and Multivariate Model

Descriptive statistics for the 11 explanatory variables (including Hourly Wind Load) and the ERCOT Interconnection FR are listed in **Table E.14**.

Table E.14: Descriptive Statistics: ERCOT Interconnection						
Variable	**N**	**Mean**	**Standard Dev.**	**Median**	**Minimum**	**Maximum**
Time	203				12/1/2011	11/30/2016
Winter	203	0.20	0.40	0	0	1
Spring	203	0.28	0.45	0	0	1
Summer	203	0.30	0.46	0	0	1
Fall	203	0.23	0.42	0	0	1
Predisturbance Frequency A (Hz)	203	60.00	0.02	60.00	59.95	60.03
Margin = C-UFLS (Hz)	203	0.55	0.05	0.56	0.41	0.82
On-Peak Hours	203	0.64	0.48	1	0	1
Interconnection Load (MW)	203	42,153	10,438	40,015	23,905	67,209
Load Change by Hour (MW)	203	92	1,760	8	-4937	4,601
Wind Load (MW)	203	3,834	2,634	3,057	81	13,865
Frequency Response	203	719	248	689	337	2,304

[138] Regressors in the final model have p-values not exceeding 0.1

For all variables, the data is available for the 203 FR events that occurred from 2012–2016 operating years. The correlation and a single-regression analysis result in the hierarchy of the explanatory variables for the ERCOT Interconnection FR shown in **Table E.15**. The table lists p-values of the test on the significance of correlation between each explanatory variable and FR. If p-value is smaller than 0.1, the correlation is statistically significant at the 0.1 significance level. For such a variable, the value of a coefficient of determination R^2 in the last column indicates the percentage in variability of the FR data that can be explained by variability of this explanatory variable.

Table E.15: Correlation and Regression Analysis: ERCOT Interconnection

Explanatory Variable	Correlation with FR	P-value	R^2 (If Statistically Significant[139])
Predisturbance Frequency A (Hz)	-0.362	<.0001	13.1%
Time	0.323	<.0001	10.5%
Wind Load (MW)	0.219	0.002	4.8%
Interconnection Load (MW)	0.135	0.055	1.8%
Summer	0.132	0.060	1.8%
Winter	-0.123	0.080	1.5%
Margin = C-UFLS (Hz)	-0.100	0.157	N/A
Spring	-0.078	0.271	N/A
On-Peak Hours	-0.073	0.303	N/A
Fall	0.055	0.436	N/A
Load Change by Hour (MW)	-0.015	0.833	N/A

Out of the 11 parameters, five are statistically significantly correlated with ERCOT's FR. Predisturbance Frequency A has the strongest correlation with and the greatest explanatory power (13.1 percent) for the FR. A and FR are negatively correlated (the higher A the smaller expected FR). On average, the frequency response decreases by 36.3 MW/0.1 Hz as A increases by 10 mHz. Time and FR are positively correlated; on average, frequency response improves in time. The average rate of the FR increase over the 2012–2016 operating years is 4.3 MW/0.1 Hz a month.

Next, wind load and interconnection load are positively correlated with FR; it is noteworthy that the correlation of FR with Wind generation is stronger than with the overall load (almost 5 percent in the variability of ERCOT frequency response in 2012–2016 can be explained by variability in its wind generation) and that there is no significant correlation between wind and overall interconnection load during FR events. On average, a wind load increase of 1,000 MW corresponds to a frequency response increase of 25.7 MW/0.1 Hz, while an Interconnection load increase of 1,000 MW corresponds to a frequency response increase of 3.2 MW/0.1 Hz. Note that both wind generation and interconnection load significantly grew over the 2012–2016 operating years.

Last, indicators of summer and winter have a statistically significant correlation with the ERCOT FR. On average, summer events have a significantly higher FR than the other seasons combined (769 MW/0.1 Hz versus 698 MW/0.1 Hz); the summer events variance is similar to events from the other seasons. The indicator of winter has a negative correlation with FR, which means that winter events have smaller FR on average than the other seasons

[139] At the significance level 0.1

(658 MW/0.1 Hz versus 734 MW/0.1 Hz); their variance is similar to events for the other seasons combined. The remaining six variables do not have a statistically significant[140] linear relationship with FR.

Both the step-wise selection algorithm and the forward selection algorithm result in a multiple regression model that connects the ERCOT Interconnection FR with time, Predisturbance Frequency A and Wind load (the other eight variables are not selected or were eliminated as regressors).[141] The coefficients of the multiple model are listed in **Table E.16**.

Table E.16: Coefficients of Multiple Model - ERCOT Interconnection						
Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	286,931	46,774	6.13	<.0001	0.00
Time	1	0.00000159	0.00	5.03	<.0001	1.07
Predisturbance Frequency A (Hz)	1	-4817	780	-6.17	<.0001	1.01
Wind Load	1	0.011	0.006	1.92	0.0569	1.07

The model's adjusted coefficient of multiple determination adj R^2 is 25.4 percent (that is the model accounts for more than 25 percent of the ERCOT FR variability); the model is highly statistically significant ($p < 0.0001$). The random error has a zero mean and the sample deviation σ of 214 MW/0.1 Hz. Variance inflation factors for the regressors do not exceed four, and this confirms an acceptable level of multicollinearity that does not affect a general applicability of the model. The parameter estimates, or the coefficients for the regressors, indicate how change in a regressor value impacts FR.

Québec: Correlation Analysis and Multivariate Model

Descriptive statistics for the 11 explanatory variables and the Québec Interconnection FR are in **Table E.17**.

Table E.17: Descriptive Statistics - Québec Interconnection						
Variable	N	Mean	Standard Dev.	Median	Minimum	Maximum
Time	171				12/1/2011	11/30/2016
Winter	171	0.12	0.33	0	0	1
Spring	171	0.20	0.40	0	0	1
Summer	171	0.41	0.49	0	0	1
Fall	171	0.26	0.44	0	0	1
Predisturbance Frequency A (Hz)	171	60.00	0.02	60.00	59.94	60.06
Margin = C-UFLS (Hz)	171	1.19	0.45	1.07	0.29	2.28
On-Peak Hours	171	0.66	0.47	1	0	1
Interconnection Load (MW)	171	21,003	4,558	19,330	13,520	35,000
Load Change by Hour (MW)	171	2	711	-40	-2010	2,450

140 At the significance level 0.1

141 Regressors in the final model have p-values not exceeding 0.1.

Table E.17: Descriptive Statistics - Québec Interconnection						
Variable	**N**	**Mean**	**Standard Dev.**	**Median**	**Minimum**	**Maximum**
Wind Load (MW)	144	753	575	651	8	2,475
Frequency Response	171	613	234	546	288	1,900

The Wind generation hourly data are available for the 144 frequency response events that occurred from 2013–2016. Other data are available for all 171 events.

The correlation and a single-regression analysis result in the hierarchy of the explanatory variables for the Québec Interconnection FR shown in **Table E.18**. The table lists p-values of the test on the significance of correlation between each explanatory variable and FR. If p-value is smaller than 0.1, the correlation is statistically significant at the 0.1 significance level. For such a variable, the value of a coefficient of determination R^2 in the last column indicates the percentage in variability of the FR data that can be explained by variability of this explanatory variable.

Table E.18: Correlation and Regression Analysis: Québec Interconnection			
Explanatory Variable	**Correlation with FR**	**P-value**	**R^2 (If Statistically Significant)[142]**
Interconnection Load (MW)	0.319	<.0001	10.2%
Margin = C-UFLS (Hz)	0.214	0.0049	4.6%
Winter	0.203	0.008	4.1%
Spring	0.195	0.010	3.8%
Summer	-0.164	0.032	2.7%
Predisturbance Frequency A (Hz)	-0.153	0.046	2.3%
Fall	-0.147	0.055	2.2%
Time	-0.125	0.105	N/A
On-Peak Hours	-0.081	0.295	N/A
Load Change by Hour (MW)	-0.078	0.309	N/A
Wind Load (MW)	0.055	0.509	N/A

Seven explanatory variables are statistically significantly correlated with FR. Interconnection load has the strongest correlation and the greatest explanatory power (10.2 percent) for the FR. The load level and FR are positively correlated (i.e., the higher interconnection load is during a frequency response event, the higher expected frequency response value of this event). On average, a load increase of 1,000 MW leads to a frequency response increase of 16.4 MW/0.1 Hz. The margin is positively correlated with FR: on average, a margin increase of 10 mHz corresponds to a FR increase of 1.1 MW/0.1 Hz.

All four seasons are statistically significantly correlated with FR. On average, winter and spring events have significantly higher frequency response than the other seasons combined (739 MW/0.1 Hz versus 595 MW/0.1 Hz

[142] At the significance level 0.1

and 703 MW/0.1 Hz versus 590 MW/0.1 Hz, respectively). The spring events (unlike winter events) have significantly greater FR variance than the other seasons combined. Next, the summer and fall events have, on average, significantly smaller frequency response than the other seasons combined (567 MW/0.1 Hz versus 645 MW/0.1 Hz and 556 MW/0.1 Hz versus 633 MW/0.1 Hz, respectively) and significantly smaller FR variance than the other seasons. The main reason winter events have a higher FR is because winter is the peak usage season in the Québec Interconnection. More generator units are on-line; therefore, there is more inertia in the system, so it is more robust in responding to frequency changes in the winter (the highly significant positive correlation between variables winter and interconnection load also confirms this). Another observation is that only 12 percent of the Québec Interconnection events have occurred in winter.

Finally, A and FR are statistically significantly and negatively correlated; on average, frequency response decreases by 19.3 MW/0.1 Hz as A increases by 10 mHz. Note that unlike the EI, the QI events do not show a correlation between A and margin (p-value of the test on the significance of correlation is 0.42). The remaining four variables do not have a statistically significant[143] linear relationship with FR.

Since wind load is not significantly correlated with FR, and this variable is excluded from the multiple regression model to keep the sample size larger (171 observations versus 144). Both the step-wise selection algorithm and the backward elimination algorithm result in a multiple regression model that connects the Québec Interconnection FR with fall, Predisturbance Frequency A, margin and interconnection load (the other variables are not selected or were eliminated).[144] The coefficients of the multiple model are listed in **Table E.19**.

Table E.19: Coefficients of Multiple Model: Québec Interconnection

Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	161,567	53,350.0	3.03	0.003	0
Fall	1	-97.55	37.2	-2.62	0.010	1.037
Predisturbance Frequency A (Hz)	1	-2690.1	889.2	-3.03	0.003	1.042
Margin = C-UFLS (Hz)	1	114.8	35.7	3.21	0.002	1.005
Interconnection Load (MW)	1	0.0163	0.0035	4.61	<.0001	1.002

The model's adjusted coefficient of multiple determination adj R^2 is 19.0 percent (19 percent of the Québec Interconnection FR variability can be explained by the combined variability of these four parameters); the model is highly statistically significant ($p<0.0001$). The random error has a zero mean and a sample deviation σ of 210 MW/0.1 Hz. Variance inflation factors for the regressors do not exceed 1.05, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model. Variables of winter and summer bring little new information about variability of FR due to their high correlation with Interconnection Load; therefore, they become redundant and eliminated from the model. On the other hand, Predisturbance Frequency and Margin (and, thus, A and nadir C) are not significantly correlated and both stay in the final model.

Western Interconnection: Correlation Analysis and Multivariate Model

Descriptive statistics for the 13 explanatory variables (including wind, solar, and hydro loads by hour). The Western Interconnection FRs are listed in **Table E.20**.

[143] At the significance level 0.1.

[144] Regressors in the final model have p-values not exceeding 0.1.

Table E.20: Descriptive Statistics - Western Interconnection						
Variable	**N**	**Mean**	**Standard Dev.**	**Median**	**Minimum**	**Maximum**
Time	103				12/1/2011	11/30/2016
Winter	103	0.16	0.36	0	0	1
Spring	103	0.23	0.42	0	0	1
Summer	103	0.28	0.45	0	0	1
Fall	103	0.33	0.47	0	0	1
Predisturbance Frequency A (Hz)	103	60.00	0.02	60.00	59.97	60.05
Margin = C-UFLS (Hz)	103	0.40	0.04	0.41	0.17	0.46
On-Peak Hours	103	0.57	0.50	1	0	1
Interconnection Load (MW)	56	89,539	15,248	87,355	65,733	146,424
Load Change by Hour (MW)	56	1571	3331	1929	-6311	6404
Wind Load	51	4,695	2,627	3,735	1,125	11,339
Hydro Load	51	30,174	6,557	31,562	16,405	43,105
Solar Load	51	2,046	1,959	1,699	0	6,033
Frequency Response	103	1,437	498	1,350	822	4,368

Interconnection load and interconnection load change by hour data are available for the 56 frequency response events that occurred during the 2012–2015 years. Renewable generation (Wind, Hydro, and Solar Load) is available by source for the 2013–2015 events. Other data is available for all 103 events.

The correlation and a single-regression analysis result in the hierarchy of the explanatory variables for the Western Interconnection FR are shown in **Table E.21**. The table lists p-values of the test on the significance of correlation between each explanatory variable and FR. If the p-value is smaller than 0.1, the correlation is statistically significant at the 0.1 significance level. For such a variable, the value of a coefficient of determination R^2 in the last column indicates the percentage in variability of the FR data that can be explained by variability of this explanatory variable.

Table E21: Correlation and Regression Analysis: Western Interconnection			
Explanatory Variable	**Correlation with FR**	**P-value**	**R^2 (If Statistically Significant[145])**
Interconnection Load (MW)	0.361	0.006	13.0%
Predisturbance Frequency A (Hz)	-0.340	0.001	11.5%
Hydro Load	0.303	0.031	9.2%
Spring	0.191	0.053	3.7%
Solar Load	0.163	0.252	N/A
Load Change by Hour (MW)	0.148	0.277	N/A
Fall	-0.127	0.202	N/A
Time	0.125	0.209	N/A
On-Peak Hours	0.112	0.261	N/A
Summer	-0.028	0.782	N/A
Winter	-0.024	0.807	N/A
Wind Load	0.015	0.917	N/A
Margin = C-UFLS (Hz)	-0.006	0.952	N/A

Four explanatory variables are statistically significantly correlated with FR. Interconnection Load has the strongest correlation and the greatest explanatory power (13 percent) for the FR. The load level and FR are positively correlated (i.e., the higher Interconnection Load is during a frequency response event—the higher expected frequency response of this event). On average, a load increase of 1,000 MW leads to a frequency response increase of 6.0 MW/0.1 Hz. Next, Predisturbance Frequency A and FR are statistically significantly and negatively correlated; on average, frequency response decreases by 105.0 MW/0.1 Hz as A increases by 10 mHz. Hydro generation is positively correlated with FR; on average, a hydro load increase of 1,000 MW leads to a frequency response increase of 11.6 MW/0.1 Hz. It is interesting to note that the Hydro load and the overall load for the WI events are not correlated (p-value of the test on the significance of correlation is 0.32).

Out of four seasons, only spring is statistically significantly correlated with FR. On average, the spring events have higher frequency response than the other seasons combined (1,609 MW/0.1 Hz versus 1,384 MW/0.1 Hz); they also have significantly greater FR variance than the other seasons combined. The remaining nine variables do not have a statistically significant[146] linear relationship with FR.

Even though five explanatory variables have smaller data size than the others, their exclusion from a multiple regression model do not improve the model (neither by increasing its explanatory power nor by reducing the error). Using all 13 variables as input regressors, the step-wise selection algorithm results in a multiple regression model that connects the Western Interconnection FR with interconnection load and indicator of on-peak hours (the other variables are not selected or were eliminated).[147] The coefficients of the multiple model are listed in **Table E.22**.

[145] At the significance level 0.1.

[146] At the significance level 0.1.

[147] Regressors in the final model have p-values not exceeding 0.1.

Table E.22: Coefficients of Multiple Model - Western Interconnection						
Variable	DF	Parameter Estimate	Standard Error	t-value	p-value	Variance Inflation Value
Intercept	1	832.9	183.7	4.53	<.0001	0.00
On-Peak Hours	1	155.1	68.6	2.26	0.028	1.11
Interconnection Load (MW)	1	0.0046	0.0021	2	0.035	1.11

The adjusted coefficient of the determination adj R^2 of the model is 19.8 percent; the model is highly statistically significant ($p<0.0001$). The random error has a zero mean and the sample deviation σ of 225 MW/0.1 Hz. Variance inflation factors for the regressors are close to 1, which confirms an acceptable level of multicollinearity that does not affect a general applicability of the model even though the two regressors are significantly correlated. Overall, the small sample size of the WI data does not allow the building of a good predictive model; it should be refined when more data becomes available

M-6 Disturbance Control Standard Failures

Background

This metric measures the ability of a BA or reserve sharing group (RSG) to balance resources and demand following a reportable disturbance, thereby returning the interconnection frequency to within defined limits; this could include the deployment of contingency reserves. The relative percent recovery of a BA's or RSG's area control error (ACE) provides an indication of performance for disturbances that are equal to or less than the most severe single contingency (MSSC). NERC Reliability Standard BAL-002-1[148] requires that a BA or RSG evaluate performance for all reportable disturbances and report findings to NERC on a quarterly basis.

M-7 Disturbance Control Events Greater than Most Severe Single Contingency (MSSC)

Background

This metric measures the ability of a BA or RSG to balance resources and demand following reportable disturbances that are greater than their MSSC. The results will help measure how much risk the system is exposed to during extreme contingencies and how often they occur. NERC Reliability Standard BAL-002-1 requires that a BA or RSG report all disturbance control standard (DCS) events and instances of nonrecovery to NERC, including events greater than MSSC.

Assessment for M-6 and M-7

Figure E.16 shows that the trend of M-6 DCS-reportable events is essentially unchanged in 2016 from 2013, 2014, and corrected 2015 data. **Table E.23** shows that in 2016, there was no M-6 DCS event for which there was less than 100 percent recovery within the determined period.

Figure E.16 also shows that the number of M-7 events were higher in 2016 than in 2015, although still considerably lower than in 2012, 2013, or 2014. There was one M-7 event in 2016 for which 100 percent recovery was not achieved within the required timeframe.

Based on the similar annual results over the last four years, M-6 is stable.

[148] http://www.nerc.com/files/BAL-002-1.pdf

Based on the improvement in both 2016 and 2015 relative to 2012–2014, M-7 is stable for the short term in the approved state achieved in 2015.

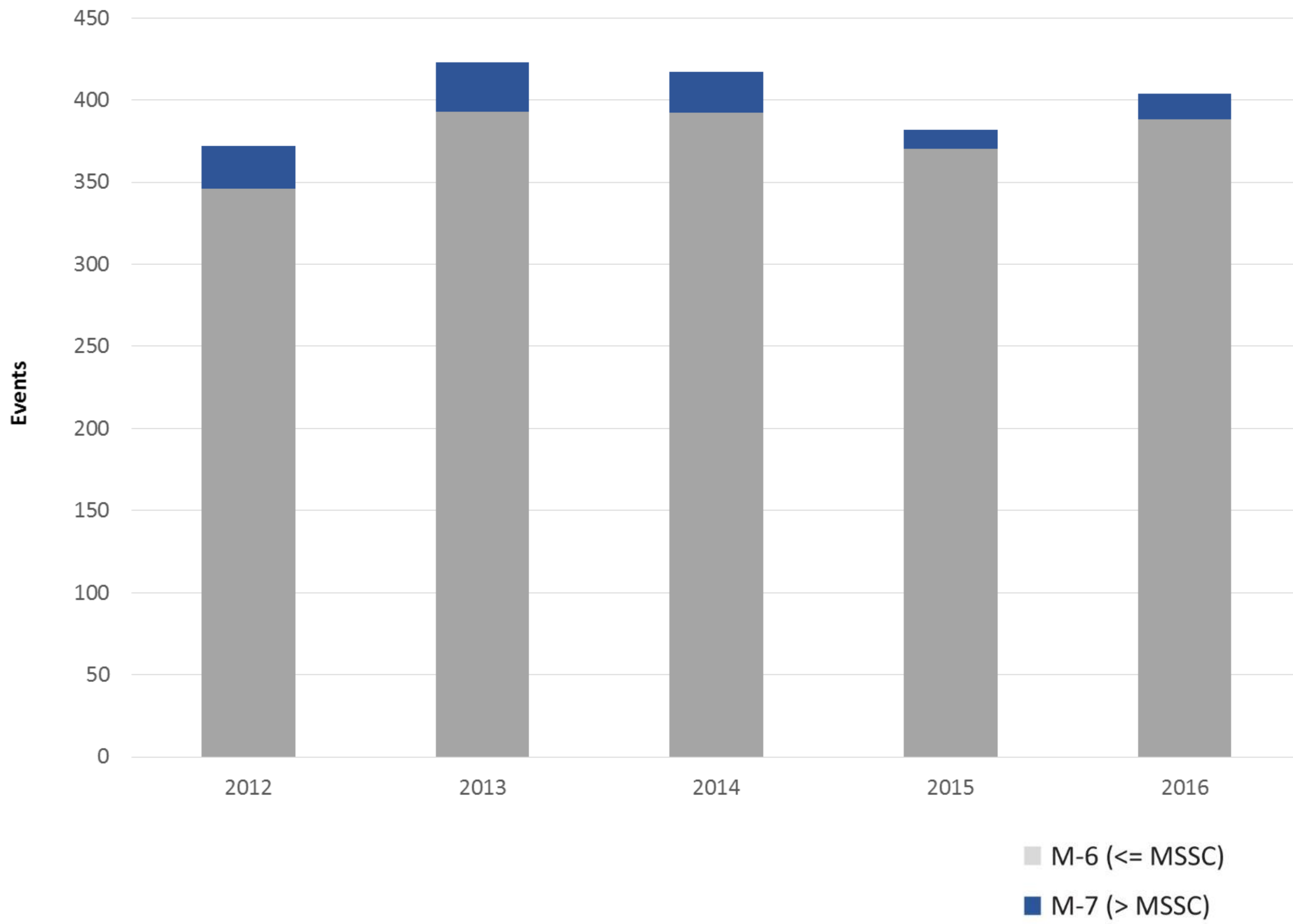

Figure E.16: M-6 & M-7 DCS Events

Table E.23: M-6 & M-7 DCS Events				
YEAR	M-6 100% Recovery	M-6 < 100% Recovery	M-7 100% Recovery	M-7 < 100% Recovery
2012	346	0	26	2
2013	390	3	28	2
2014	392	0	25	0
2015	370	1	12	0
2016	388	0	15	1

M-8 Interconnection Reliability Operating Limit Exceedances

Background

This metric measures both the number of times and duration that an IROL is exceeded. An IROL is a SOL that, if violated, could lead to instability, uncontrolled separation, or cascading outages.[149] Each RC is required to operate

[149] T_v is the maximum time that an interconnection reliability operating limit can be violated before the risk to the interconnection or other RC area(s) becomes greater than acceptable. Each interconnection reliability operating limit's T_v shall be less than or equal to 30 minutes.

within IROL limits and minimize the duration of such exceedances. IROL exceedance data is reported in four duration intervals as shown in **Figures E.17** through **Figure E.19**.

Assessment

Figure E.17 demonstrates the performance for the EI from 2011–2016. The *State of Reliability 2015* described some changes in data reporting for two of the Regions in the EI that led to an increase in the number of exceedances in 2014. In 2015, the number of exceedances declined from 2014 levels. While the number of exceedances less than 10 mins increased a declining trend of exceedances greater than 10 mins can be seen. This may have signaled an increase in operating near an IROL limit but a decrease in time necessary to respond to operations outside of IROL limits. In 2016, the number of exceedances increased not only in the less than 10 mins range but also in the greater than 10 mins.

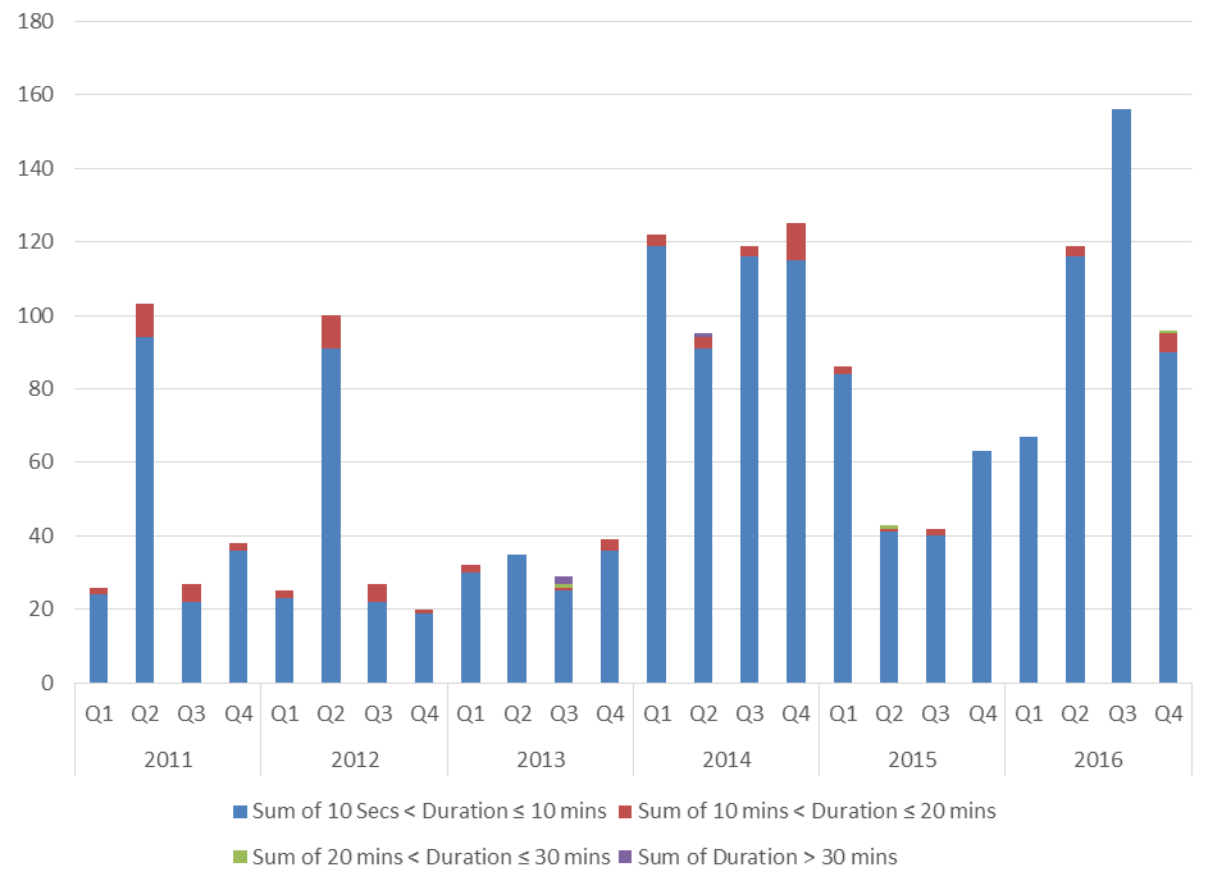

Figure E.17: Eastern Interconnection: IROL Exceedances

Figure E.18 demonstrates the performance of the ERCOT Interconnection from 2011-2016. The trend has been stable at no exceedances since the second quarter of 2013.

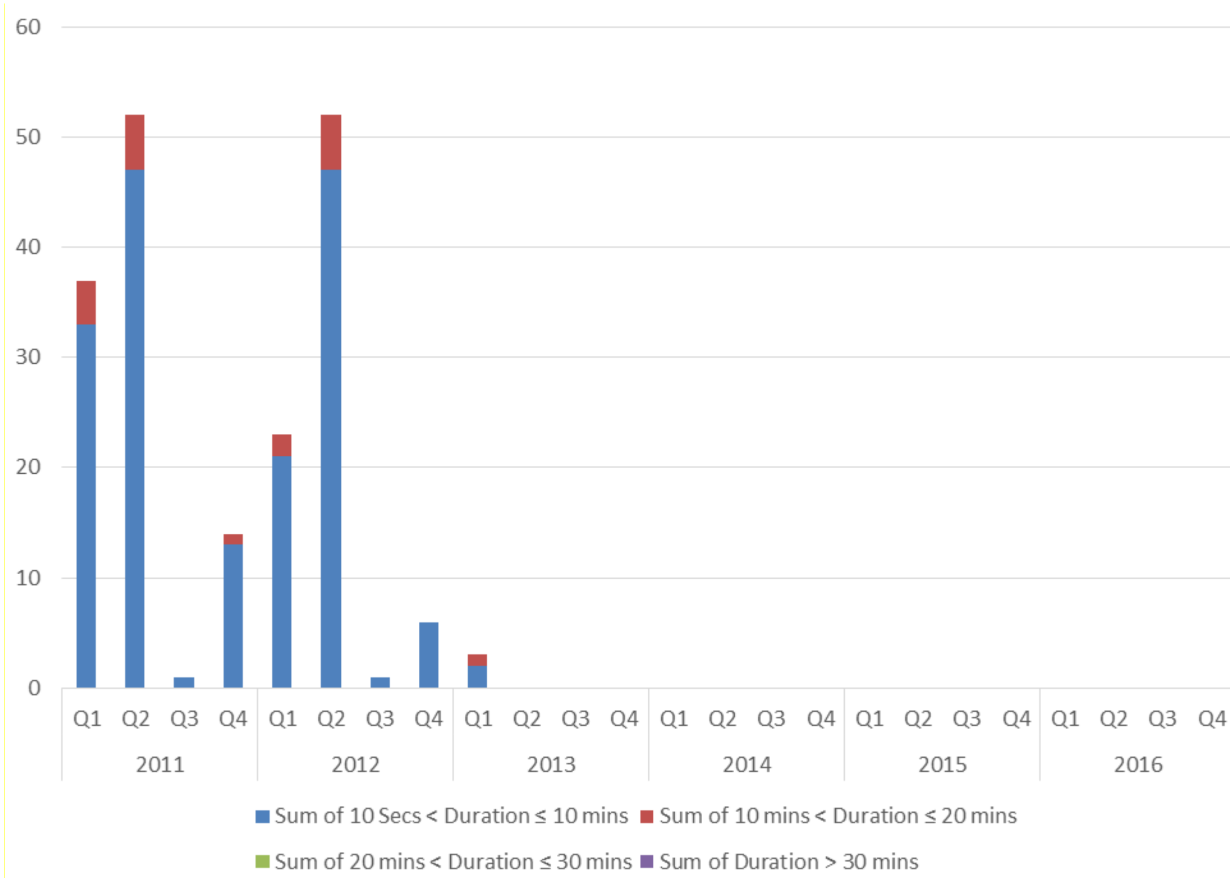

Figure E.18: ERCOT Interconnection: IROL Exceedances

Figure E.19 demonstrates performance for the Western Interconnection from 2011–2016. The *State of Reliability Report 2015* noted changes in data reporting for the Western Interconnection that led to the reporting of IROLs. Prior to 2014, only SOLs were reported. Since 2014, the trend has been stable with no IROL exceedances reported.

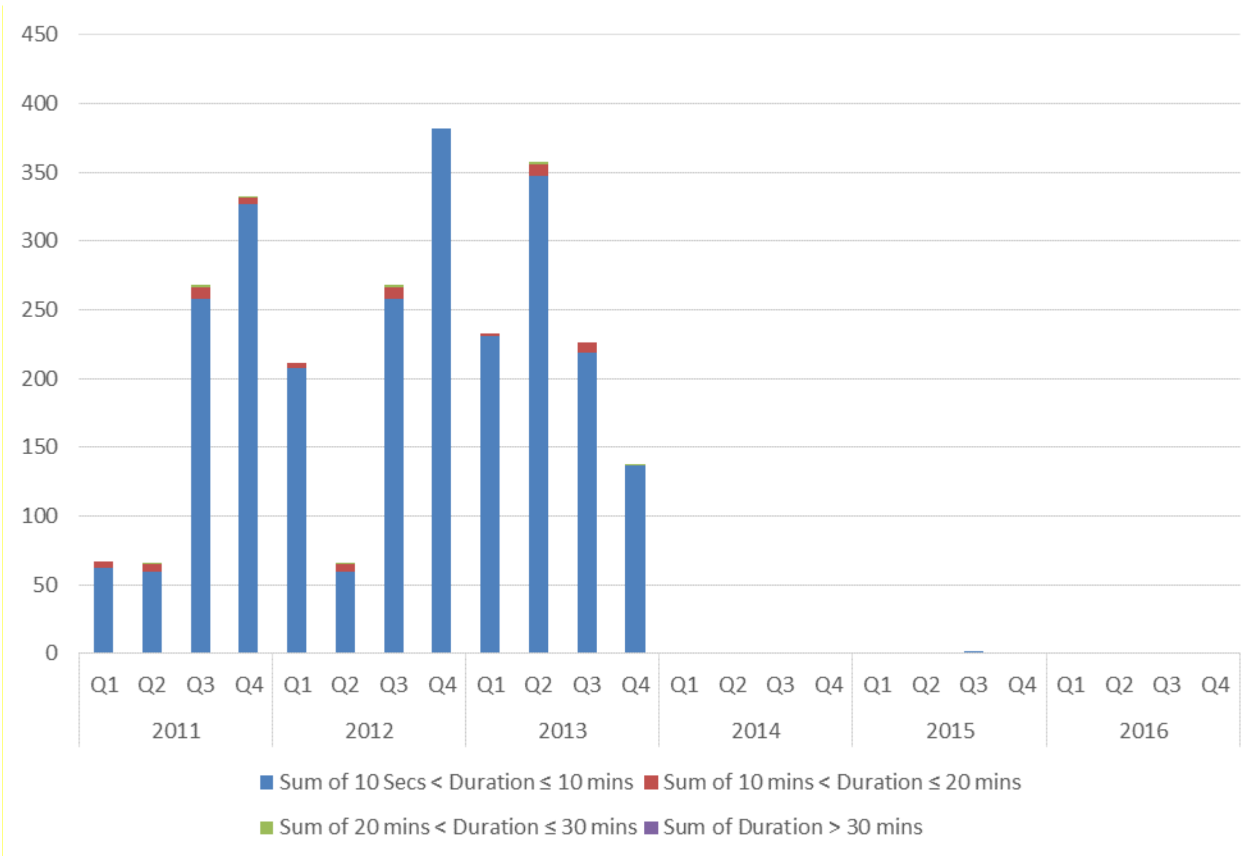

Figure E.19: Western Interconnection – SOL/IROL Exceedances

M-9 Correct Protection System Operations

Background

Protection system misoperations were identified as an area that required further analysis in past *State of Reliability* reports. The improvements to the data collection process, that the SPCS proposed, were implemented and have improved the accuracy of misoperation reporting. At the recommendation of the SPCS, the respective protection system subcommittees (within each RE) began misoperation analysis in early 2014 and have continued to conduct such analysis on an annual basis. In 2016, NERC updated to an online collection of data with updates and enhancements to the system expected in 2017.

Assessment

Figure 4.4 shows the correct operations rate for NERC during the reporting period. Total protection system operations were first requested with fourth quarter 2012 misoperations data. This is to reflect the updated metric M-9 Correct Protection System Operations. The rate provides a consistent way to trend misoperations and to normalize for weather and other factors that can influence the count. Incremental improvements continue to be seen.

Figure E.20 shows the count of misoperations by month through the third quarter of 2016. The counts can show variability or similarity by year for each month and seasonal trends. For example, the chart shows higher numbers of misoperations in summer than the rest of the year.

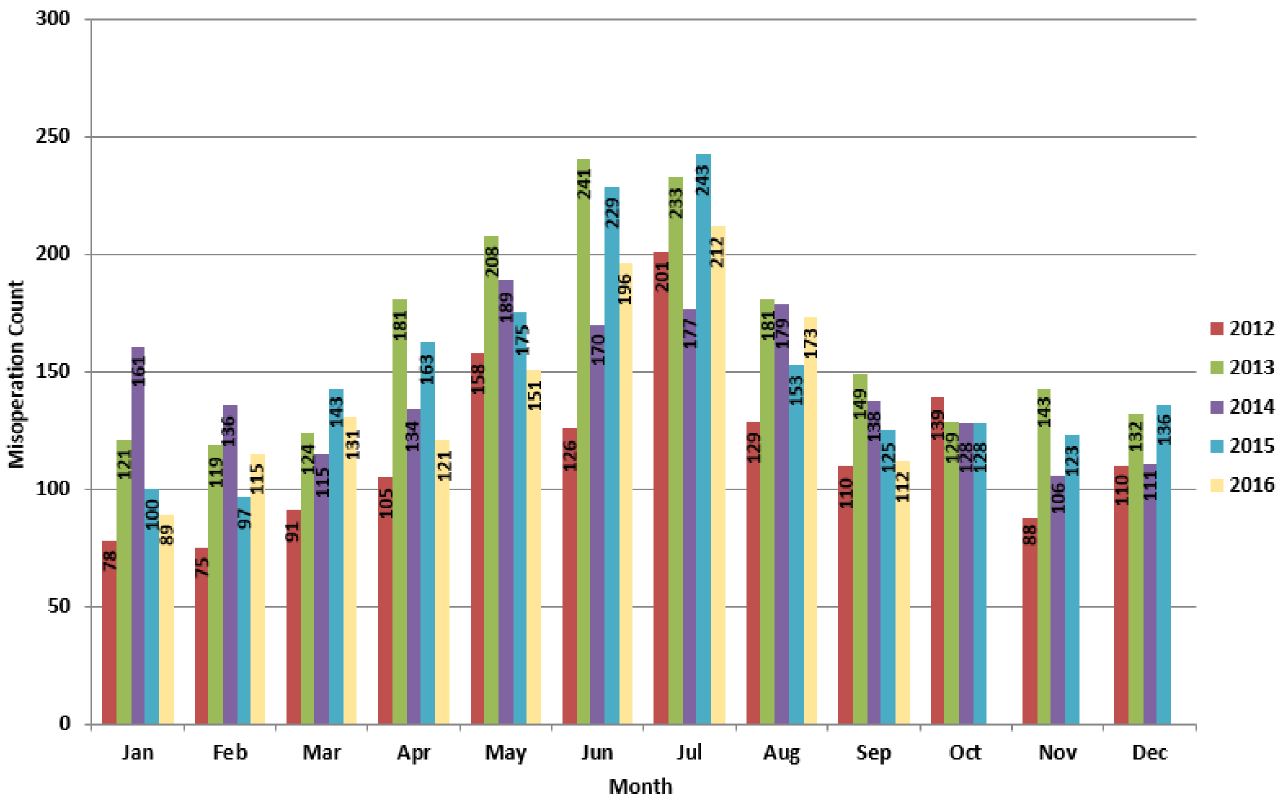

Figure E.20: Protection System Misoperations by Month (2Q 2012–3Q 2016)

Figure E.21 illustrates misoperations by cause code where the top three causes continue to be incorrect setting, logic, or design error; relay failures/malfunctions; and communication failure. These cause codes have consistently accounted for approximately 65 percent of all misoperations since data collection started in 2011. Recent reporting updates have broken down the single "Incorrect Setting, Logic, or Design Error" cause code into separate cause codes of "Incorrect Settings," "Logic Errors," and "Design Errors" to allow analysis at a higher granularity to address issues that may exist in one of the cause code subgroups. In Figure E.21, however, these causes are still shown by an aggregated wedge and are analyzed together (illustrated in Figure 4.7) for a consistent year-to-year comparison over the four-year time frame.

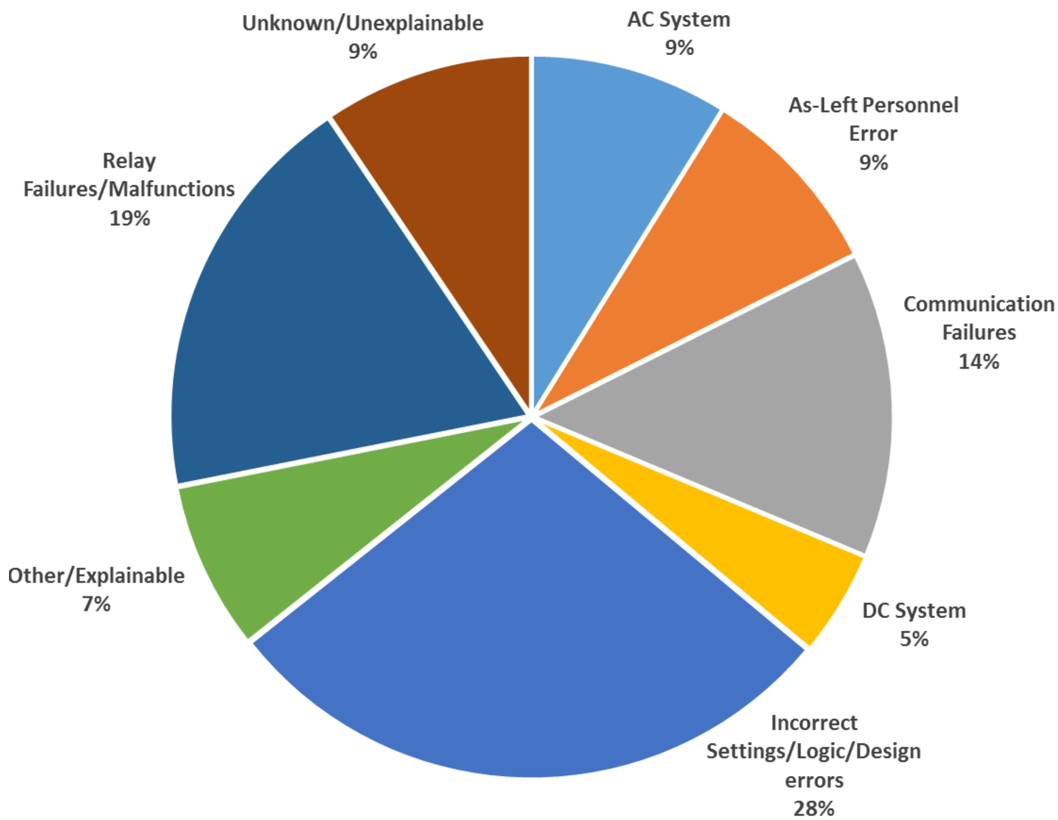

Figure E.21: NERC Misoperations by Cause Code (2Q 2012–3Q 2016)

Linkage between Misoperations and Transmission-Related Qualified Events

An analysis of misoperation data and events in the EA Process found that in 2015 there were 50 transmission-related system disturbances which resulted in a qualified event. Of those 50 events, 34 events, or 68 percent, had associated misoperations. Of the 34 events, 33 of them, or 97 percent, experienced misoperations that significantly increased the severity of the event. There were four events where one or more misoperations and a substation equipment failure occurred in the same event. The relay ground function accounted for 11 misoperations in 2014 causing events that were analyzed in the EA Process. This was reduced to six events in 2015. It was further reduced to only one event in 2016. The focus on the relay ground function has been attended by a reduction in its involvement in qualified events. It is not clear if any statistical basis will be able to confirm that its role in relay misoperations has been similarly decreasing.

Actions to Address Misoperations

To increase awareness and transparency, NERC will continue to conduct industry webinars[150] on protection systems and document success stories on how GOs and TOs are achieving high levels of protection system performance. The quarterly protection system misoperation trend can be viewed on NERC's website.[151]

NERC introduced MIDAS in 2016, a data collection site for misoperations. MIDAS updates are scheduled for 2017 to improve data submission and analysis. NERC collaborates closely with the Regions to relay best practices and improve data collection.

Summaries of Individual Regional Entity Initiatives:

[150] http://www.nerc.com/files/misoperations_webinar_master_deck_final.pdf
[151] http://www.nerc.com/pa/RAPA/ri/Pages/ProtectionSystemMisoperations.aspx

FRCC

The FRCC SPCS conducted peer reviews of protection system misoperations prior to the protection system owners submitting the data to NERC MIDAS. The FRCC SPCS is a member services group but includes FRCC staff as part of the review. The subcommittee is working on developing new and refining existing internal metrics with FRCC staff in order to better understand where to focus attention in the FRCC footprint. In 2017, FRCC will be conducting a misoperations assessment to identify lessons learned and make recommendations for improvements at the entity and Region levels.

MRO

The MRO Protective Relay Subcommittee (PRS) is preparing a second white paper to discuss the misoperation modes of several protection system schemes that have been observed to have a greater negative impact on system reliability within MRO. This paper will then identify effective approaches to reduce their occurrence. This paper will be distributed to all applicable Entities and also presented at the MRO annual Reliability Conference.

The MRO has also conducted event review meetings between the PRS and entities experiencing particularly severe events involving misoperations. The intent of these meeting is both to provide additional expertise and experience to the reporting entities, and to also disseminate lessons learned from the event to other entities.

Finally, MRO will be altering its misoperation review policy to conform to the requirements of NERC’s MIDAS reporting application.

NPCC

The NPCC has instituted a procedure for peer review and analysis of all NPCC protection system misoperations. The NPCC review process is intended as a feedback mechanism that promotes continuous improvements based on lessons learned from reported protection system misoperations. The NPCC task force on system protection reviewed NERC lessons learned and NPCC-reported protection system misoperations while providing regional perspectives for entities’ use to further improve performance and reduce misoperations.

NPCC collected additional data on microprocessor-based relay misoperations to develop potential measures that address misoperations caused by Incorrect Setting/Logic/Design Errors and to share knowledge of identified relay vendor specific product concerns along with the vendor recommended mitigations.

RF

RF has addressed the NERC misoperation reduction goal by providing training opportunities on protection topics to RF’s member entities. The RF Protection Subcommittee has initiated annual refresher training in the areas of protection issues identified as the top misoperation causes in the Region and in NERC. The topics have included design concepts for protection communication systems and polarization techniques associated with protection system settings. In 2016, RF added a training opportunity for field protection engineers and technicians; these personnel are responsible for the installation and (commissioning) testing of protection system equipment, and they ensure that these protection systems are installed and function as designed. RF will continue to offer these opportunities into the future and has invited the other Regions to participate.

Also, in 2016, RF implemented a peer review process using members of the RF Protection Subcommittee to analyze the reported misoperations and to offer feedback on analysis and mitigation techniques. This process leverages the expertise and experiences of the Protection Subcommittee to help entities in the Region reduce their misoperations.

SERC

The SERC Protection and Controls Subcommittee (PCS) has created a SERC Regional Best Practices for Protection System Misoperations Reduction[152] paper for entities to reference. SERC has also developed a metric to measure risk based on cause, category, voltage, Misoperation rate, and CAP response time.

SPP RE

The SPP System Protection & Control Working Group (SPCWG) has prepared a white paper discussing misoperations caused by communication failures,[153] a leading cause of misoperations in the SPP Region. The SPCWG is currently working on a white paper that discusses misoperations caused by Incorrect Settings/Logic/Design Errors, the second leading cause of misoperations in the SPP Region. These white papers then identify effective approaches to reduce misoperation occurrences.

Texas RE

Texas RE has worked with ERCOT's System Protection Working Group (SPWG) on the following:

- Development and monitoring of multiple metrics and historical trends for misoperations by voltage class, cause, corrective action plan completion rates, etc.
- Development of a metric on human performance issues as it relates to the cause of misoperations
- Presentation of the analysis and summary of quarterly protection system misoperation data and historical trends at each SPWG meeting
- Analysis of historical misoperations due to incorrect settings and determination that over 40 percent were due to ground fault overcurrent coordination issues
- Assisted the SPWG in the creation of a white paper to document best practices regarding ground overcurrent coordination to be shared among all entities in the Region

These efforts have raised the awareness of the main causes of misoperations in the Region and have led to the reduction in misoperations caused by Incorrect Settings, Logic, and Design Errors.

WECC

WECC tracks trends in misoperations in its annual *State of the Interconnection*[154] report and is conducting an in-depth analysis to identify the most effective areas to focus on to reduce misoperations. WECC will publish a report in 2017 that targets the top three cause categories contributing to misoperations in the West: Incorrect Settings, Relay Failures, and Unknown. This report will include recommendations and best practices that entities can use to evaluate their own practices regarding misoperations. Through outreach efforts and working with its Relay Work Group, WECC encourages entities to evaluate their individual systems to best determine ways to reduce misoperations. WECC is working with a team of stakeholders to develop a strategy to reduce misoperations in the Western Interconnection. In Fall 2017, WECC will hold a misoperations summit to share and discuss the reduction strategy and the issue of misoperations in general.

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[152] http://www.serc1.org/docs/default-source/committee/ec-protection-and-control-subcommittee/serc-regional-best-practices-for-protection-system-misoperations-reduction-8-19-2016.pdf

[153] https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fwww.spp.org%2Fdocuments%2F23167%2Fspcwg_commmisops_whitepaper_final_mopc.doc

[154] https://www.wecc.biz/Reliability/2016%20SOTI%20Final.pdf

Misoperations Analysis

Misoperation Rate by Region and for NERC

Table E.24 lists the NERC operation and misoperation counts and the corresponding misoperation rates by Region and for NERC with the 16 available quarters (Q4 2012–Q3 2016). NERC's numbers are based on the combined data for the Regions available for the respective time periods. It should be noticed that due to an improving performance of M-9, the most recent, year 4, rate stands lower than the overall rate for the for years (8.7 percent versus 9.5 percent).

Table E.24 : Operations and Misoperations by Region from Q4 2012 to Q3 2016

Region	Operations	Misoperations	Misoperation Rate
FRCC	2,673	263	9.8%
MRO	5,624	613	10.9%
NPCC (Q1 2013 to Q3 2016)	10,126	743	7.3%
RF	10,677	1,468	13.7%
SERC	16,443	1,381	8.4%
SPP	7,975	903	11.3%
TRE	8,940	644	7.2%
WECC (Q2 and Q3 2016 only)	3,002	179	6.0%
NERC	**65,461**	**6,194**	**9.5%**

Comparison of Regional Misoperation Rates

Regional misoperation data was analyzed to find statistically significant differences[155] in misoperation rates between Regions based on the four-year data (except for Q1 2013–Q3 2016 for NPCC and Q2 and Q3 2016 for WECC). **Table E.25** shows results of the statistical tests that compare misoperation rates by Region. The second column lists Regions with a statistically significantly higher rate than the Region in each row, the fourth column lists Regions with a lower rate, and the third column—Regions with no significant difference in the misoperation rate.

Table E.25: Summary of Statistical Comparison of Regional Misoperation Rates

Region	Regions with Higher Rate	No Significant Difference	Region with Lower Rate
RF	none	none	SPP, MRO, FRCC, SERC, NPCC, TRE, WECC
SPP	RF	MRO	FRCC, SERC, NPCC, TRE, WECC
MRO	RF	SPP, FRCC	SERC, NPCC, TRE, WECC
FRCC	RF, SPP	MRO	SERC, NPCC, TRE, WECC
SERC	RF,SPP, MRO, FRCC	none	NPCC, TRE, WECC
NPCC	RF, SPP, MRO, FRCC, SERC	TRE	WECC
TRE	RF, SPP, MRO, FRCC, SERC	NPCC	WECC
WECC	RF, SPP, MRO, FRCC, SERC, NPCC, TRE	none	none

155 Large sample test on population proportions at the 0.05 significance level

M-10 Transmission Constraint Mitigation

This metric was approved for retroactive retirement by the PC in June of 2017.

Complete data for this metric was no longer collected for the *State of Reliability 2016*. The metric measured the number of mitigation plans that included SPSs, RASs, and/or operating procedures developed to meet reliability criteria.

M-11 Energy Emergency Alerts

Background

To ensure that all RCs clearly understand potential and actual energy emergencies in the interconnection, NERC has established three levels of energy emergency alerts (EEA) as detailed in EOP-002-3.1.[156]. This metric measures the duration and number of times EEAs of all levels are issued and when firm load is interrupted due to an EEA level 3 event. EEA trends may provide an indication of BPS capacity. This metric may also provide benefits to the industry when considering correlations between EEA events and planning reserve margins.

When an EEA3 alert is issued, firm-load interruptions are imminent or in progress in accordance with EOP-002-3.1. The issuance of an EEA3 may be due to a lack of available generation capacity or when resources cannot be scheduled due to transmission constraints.

Assessment

Table E.26 shows the number of EEA3 events declared from 2006–2016. Only two EEA3s were declared in 2016, one more than the previous year. However, this was less than in any year 2006–2014.

Table E.26: 2016 Energy Emergency Alert 3											
Region	Number of Events										
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
NERC	**5**	**26**	**13**	**38**	**7**	**23**	**14**	**6**	**4**	**1**	**2**
FRCC	0	0	0	0	0	0	0	1	2	0	0
MRO	0	0	0	0	0	0	0	0	0	0	0
NPCC	0	0	0	1	0	0	0	0	1	0	0
RF	0	0	0	0	0	0	0•	0	0	0	0
SERC	2	14	2	0	3	2	7	0	1	0	0
SPP	1	9	8	37	4	15	6	2	0	0	0
TRE	0	0	0	0	0	1	0	0	0	0	0
WECC	2	3	3	0	0	5	1	3	0	1	2

Table E.27 shows the number of all EEAs declared in 2016, broken out by Region as well as event level.

Table E.27: 2016 EEA Level by Region				
Region	EEA1	EEA2	EEA3	Total
FRCC	0	0	0	0
MRO	6	7	0	13
NPCC	6	4	0	10
RF	0	0	0	0
SERC	0	0	0	0

[156] http://www.nerc.com/files/EOP-002-3_1.pdf

Table E.27: 2016 EEA Level by Region				
Region	**EEA1**	**EEA2**	**EEA3**	**Total**
SPP	0	0	0	0
WECC	5	2	2	9
TRE	0	0	0	0
Grand Total	**17**	**13**	**2**	**32**

In **Figure E.22**, a graph is provided for 2013–2016, showing the duration and amount of load shed (by category), if any, by all EEAs in each year. The two 2016 EEA3s had a combined duration of 9.7 hours and 515 MW of load.

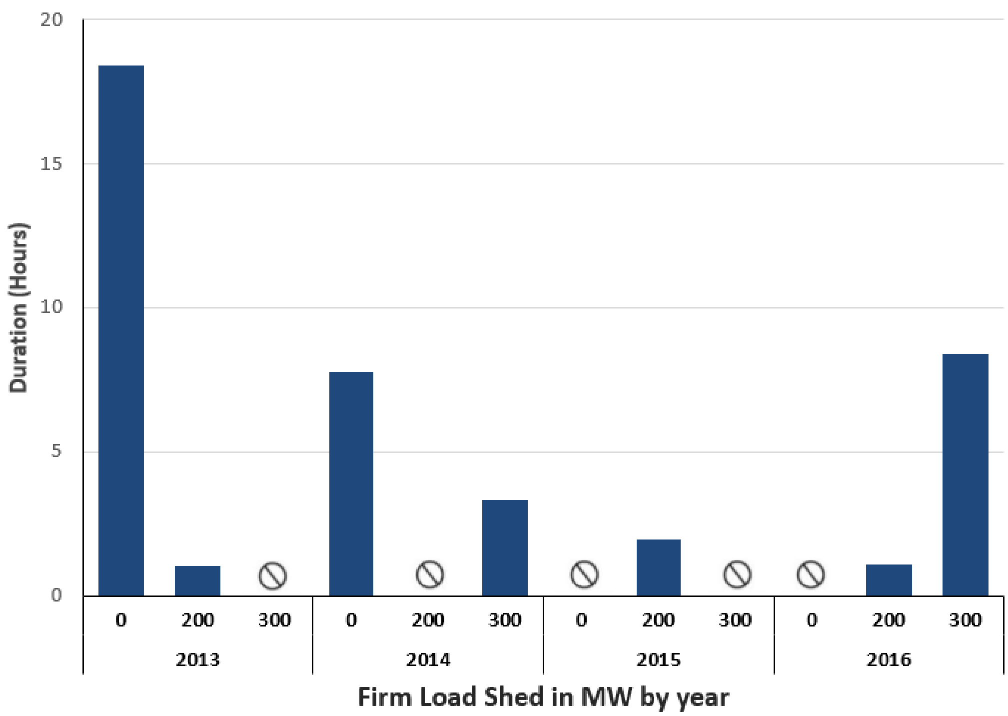

Figure E.22: Firm Load Shed and Duration Associated with EEA3 Events by Year

Appendix F: Statistical Significance Whitepaper

One of the main goals of performance analysis is to measure the performance of the BPS to identify significant reliability risk factors. This is accomplished, in part, by developing and tracking key reliability indicators. Significant changes in these indicators can point to improvements in reliability or signal reliability risks.

The significance of these changes is evaluated using *hypothesis testing*, which is a statistical method for making inferences about a population based on a representative sample. If hypothesis testing indicates the changes are indeed significant, they are referred to as *statistically significant*. This report introduces and explains statistical hypothesis testing and the meaning of the term statistically significant for readers without a background in statistics.

Theoretical Background

Statistical Hypotheses

A statistical hypothesis is a statement about the properties of a population or the relationship between different populations. Statistical tests are run on a representative sample of the population to determine if the hypothesis is true or false. Statisticians and data analysts evaluate the hypotheses by comparing data observed in reality to results expected if the statement were true. If observations differ markedly from the expectations, the hypothesis is rejected in favor of an alternative hypothesis. If they do not, the hypothesis is accepted.[157]

The statement to be disproved is called the *null hypothesis*; the statement to accept (in favor of the null hypothesis) is called the *alternative hypothesis*. For example, an engineer studying failure rates of generating units may wish to test the following hypotheses:

- Null hypothesis: "Model A units fail as often as Model B units."
- Alternative hypothesis: "Model A units fail more often than Model B units."

The exact testing procedure depends on the alternative hypothesis. Slightly different procedures would be used for the engineer to test the alternative hypothesis: that Model A units fail either more often or less often than Model B units.

Testing Statistical Hypotheses

To decide between the null and alternative hypotheses, the engineer collects samples from both types of units and calculates a *test statistic*. A test statistic is a quantity derived from these two samples. In this example, it measures "a distance" between the rates for the two populations. The distribution of the test statistic is known if the null hypothesis is true. In another words, the probability that the statistic will take any given value or belong to any given interval is known in advance.

To conduct the test, the range of possible values of the test statistic is divided into two parts: an *acceptance region* and a *critical region* as shown in **Figure F.1**. The boundary between is called the *critical value*. If the test statistic falls in the acceptance region, the sample is consistent with the null hypothesis, thus it is accepted. If the test statistic falls in the critical region, the sample is not consistent with the null hypothesis and it is rejected in favor of the alternative hypothesis.

In the above example, the engineer will calculate average observed failure rates for a sample of Model A units and a sample of Model B units. If the null hypothesis is true, and the units have the same underlying failure rate, the

[157] Some authors prefer to say "fail to reject" rather than "accept."

difference between the observed failure rates will follow a standard normal distribution with an average value of zero.[158] The test is as follows:

- The engineer rejects the null hypothesis if the difference between the observed failure rates is large due to a sampling error.[159] In that case, it can be concluded that Model A units indeed have a higher failure rate.
- On the other hand, if the difference is not much larger than zero, the null hypothesis is not rejected. The failure rate of Model A units may be smaller or equal to the failure rate of Model B units, but it is not larger.[160]

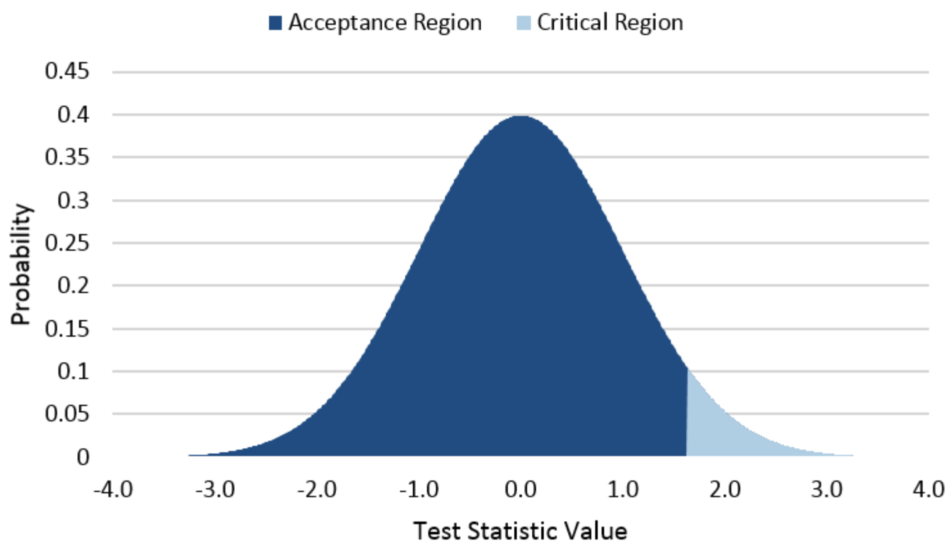

Figure F.1: Distribution of the Test Statistic If the Null Hypothesis Is True

Selecting Critical Values

There are four possible outcomes of a hypothesis test visible in **Figure 4.2**. A correct decision can be either to reject a null hypothesis when it is false or to accept a null hypothesis when it is true. However, if the null hypothesis is true, but the test statistic falls in the critical region, the analyst would falsely reject a true hypothesis. This is called a *Type I error*. If the null hypothesis is false, but the test statistic falls in the acceptance region, the analyst would falsely accept a false hypothesis. This is called a *Type II error*.

[158] This follows from the Central Limit Theorem if the sample sizes are large. The observed rates must first be multiplied by a scaling factor specified by the test.

[159] Sampling error arises from dissimilarity between a population and a sample from it. A large randomly selected sample will have less sampling error than a small nonrandom sample.

[160] The test was designed based on the alternative hypothesis, "Model A units fail more often than Model B units." No conclusion can be made about whether the Model A units fail less often. A different alternative hypothesis and test would be used for this purpose.

		Test Statistic Location	
		Critical Region	Acceptance Region
Null Hypothesis	False	Correct Rejection	Type II Error
	True	Type I Error	Correct Acceptance

Figure F.2: Possible Outcomes of a Hypothesis Test

The size of the critical region determines the probability of a Type I error. When conducting a hypothesis test, it is decided in advance how acceptable this outcome is and an appropriate *significance level* is selected accordingly. This is the probability that a Type I error will occur, the probability that a sample will lead to rejecting the null hypothesis, even though it is true. Some common values are 0.10 (10 percent chance of a Type I error) and 0.05 (Five percent chance of a Type I error). Based on the distribution of the test statistic under the null hypothesis and the selected significance level, the critical value is chosen in such a way that the probability for the test statistic to fall above it (or below, depending on the test) is equal to the significance level.[161]

The significance level cannot be set to be an arbitrarily low. As the probability of a Type I error decreases, the probability of a Type II error increases (The exact probability depends on the distribution of the test statistic.) The significance level of a test must be chosen carefully to balance the probability of each type of error.

Statistical Significance

If the test statistic falls in the critical region, the result is called *statistically significant*. It means the data does not support the null hypothesis; the probability of observing this result if the null hypothesis were true does not exceed the chosen significance level.

Instead of merely saying whether the test statistic was significant at a given significance level, it is common to report the *P-value*. The P-value of a test statistic is the probability of observing that test statistic (or the test statistic more extreme) in the event the null hypothesis is true. This value is the smallest significance level that would lead to rejecting the null hypothesis.

When documenting test results, it could be reported that the difference in failure rates was significant with a P-value of 0.03. This means that the probability of at least the observed difference occurring if the null hypothesis were true is 3 percent. Reporting the P-value, rather than simply saying the results were significant, allows readers to see why the analysts have arrived at their conclusion and to then decide for themselves whether the results are significant.

Statistical Versus Practical Significance

Depending on the nature of the population under study, it is possible for hypothesis testing to detect very small differences. If the sample size is large, and the variability in failure rates between units is small, the engineer might

[161] This rule allows a generalization for a two-sided test with several critical values.

find a statistically significant difference in failure rates that is not worth mentioning in practical terms. This practicality is often referred to as practical significance. One must take care when interpreting practical significance versus statistical significance, especially when the result will drive decision-making. Therefore, one should examine and understand the situation to determine if a result is not only statistically significant but also practically significant.

Examples from Performance Analysis

Reliability Indicator M-9: Misoperation Rate

Table F.1 presents observed protection system misoperation rates for two twelve-month periods.[162] The misoperation rate declined by 1.2 percent from one period to the next. Hypothesis testing allows us to evaluate whether this was a significant change or one simply due to chance.

Table F.1: Observed Misoperation Data			
Time Period	**Misoperations**	**Total Operations**	**Misoperation Rate**
July 2014–June 2015	1,436	14,789	9.7%
July 2015–June 2016	1,357	16,016	8.5%

First, a statistical model that will allow defining of the testable hypotheses must be established. Suppose that when an operation occurs, it will be a misoperation with a fixed but unknown probability p. Then, out of a given number of operations n, the number of misoperations x follows a binomial distribution. Then the question to answer becomes whether the misoperation rate during the first period (p_1) was significantly greater than the misoperation rate during the second period (p_2). Thus, the null and alternative hypotheses are defined as follows:

- Null hypothesis: $p_1 = p_2$
- Alternative hypothesis: $p_1 > p_2$

For large samples, such as this one, the difference between the observed misoperation rates will follow a standard normal distribution with an average value of zero.[163] Figure F.1 illustrates the acceptance and critical regions for this test with a significance level of 0.05. The null hypothesis is rejected if the test statistic is greater than 1.64. The probability of seeing a difference larger than this critical value, if the null hypothesis is true, is less than five percent.

In fact, the calculated test statistic is 3.78. This is well above the critical value, indicating that the difference is statistically significant. Its P-value (7.90×10^{-5}) is much lower than the established significance level of 0.05. To illustrate how strong this result is, it would require a confidence level of more than 99.99 percent before considering the results of this test not statistically significant. The difference in rates is much too large to be due to chance. It can be concluded that the misoperation rate decreased statistically significantly between the two time periods.

Reliability Indicator M-14: Outages Initiated by Failed Substation Equipment

Reliability Indicator M-14 is the average number of automatic outages per ac circuit 200 kV and above, initiated by Failed AC Substation Equipment. This Indicator increased between 2013 and 2014 as listed in **Table F.2**. Again, hypothesis testing was used to evaluate whether this was the result of random chance.

[162] Excluding WECC
[163] The difference in rates must first be multiplied by a scaling factor specified by the test.

Table F.2: Reliability Metric M-14			
Year	Outages Initiated by Failed AC Substation Equipment	AC Circuits > 200 kV	Outages per Circuit
2013	229	7,655	0.030
2014	267	7,753	0.033

To frame testable hypotheses, it is assumed that occurrences of the outages an ac circuit experiences follow a Poisson process with an average rate r of outages per year.[164] If the average outage rate in 2013 is r_1 and the rate in 2014 is r_2, the hypotheses are:

- Null hypothesis: $r_1 = r_2$
- Alternative hypothesis: $r_1 \neq r_2$

According to Hoel,[165] if the null hypothesis is true, a particular function $\lambda(r_1, r_2)$ follows a known distribution.[166] Figure F.3 displays the distribution of the test statistic if the null hypothesis is true. The shaded critical region reflects a 0.05 significance level. At that level, the test states the critical value to be 3.84. If the rates are equal, the probability that $\lambda(r_1, r_2)$ is greater than the critical value is less than five percent.

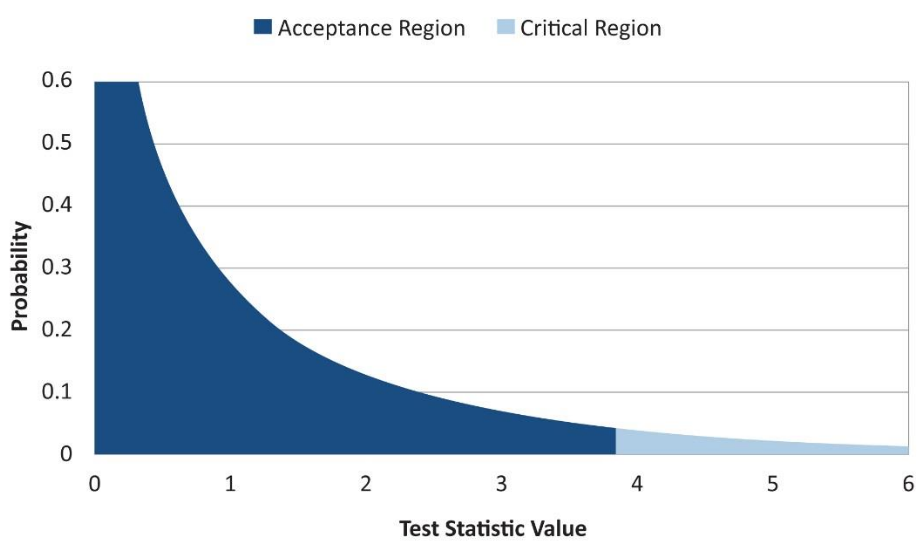

Figure F.3: Distribution of Test Statistic If Outage Rates Are Equal

In fact, the test statistic is $\lambda(r_1, r_2) = 2.45$, which has a P-value of 0.12. Since $\lambda(r_1, r_2)$ is smaller than the critical value, it belongs in the acceptance region. It is concluded that the increase in the number of outages per circuit between 2013 and 2014 is not statistically significant.

Conclusion

This report explains hypothesis testing and statistical significance for readers without a background in statistics. A hypothesis test compares real-world observations to expectations from a statistical model to choose between null and alternative hypotheses. If what is observed differs sufficiently from what is expected, the difference is called statistically significant.

[164] A Poisson process is a model describing the behavior of many natural phenomena. In a Poisson process, events occur independently of each other, according to a fixed average rate proportional to a fixed interval of time or space (in this example, the span of a year).
[165] P.G. Hoel. Testing the Homogeneity of Poisson Frequencies. 1945. Annals of Mathematical Statistics. pp. 362-368.
[166] χ^2-distribution with 1 degree of freedom.

Statistical significance does not imply practical significance. The result of a hypothesis test must be interpreted with the particular assumptions of the test and the context in mind. Interpretation should also incorporate the inherent uncertainty of the result and a relation between the predetermined probability of Type I Error and the resulting probability of Type II Error.

The most appropriate statistical test to use in a given situation must be determined by the analyst based an understanding of the fundamental nature of the population in question. This report is not a guide on making that determination.

Common Statistical Tests

Below is a list of statistical tests frequently used in NERC's reports:

- Test on significance of correlation
- Large-sample test on population proportion
- Test on significance of a regression line slope
- Test on homogeneity of Poisson frequencies
- ANOVA
- Tests on homogeneity of variance: Bartlett, F-folded
- T-tests: Fisher's Least Significant Difference, Pooled, Satterthwaite
- Nonparametric tests: Mann-Whitney, Wilcoxon, Mood
- Multiple regression model: by step-wise selection, by backward elimination
- Goodness-of-fit tests: Kolmogorov-Smirnov, Cramer-von Misses, Anderson-Darling

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Appendix G: Security Performance Metrics

Background

For the past two years, the *State of Reliability* report has included a chapter for security performance metrics based largely on data collected by NERC's E-ISAC. These metrics help provide answers to basic questions often asked by industry executives and senior managers, such as the following:

- How often do physical and cyber security incidents occur?
- To what extent do these reported incidents cause a loss of customer load?
- What is the extent of security information-sharing across the industry?
- Are cyber security vulnerabilities increasing?

These security performance metrics are derived from data collected and validated by the E-ISAC during 2015 and 2016. On a quarterly basis, the E-ISAC collaborates with the BESSMWG to review the results and ensure the definitions are being correctly applied to the raw data. In some cases, the BESSMWG has revised the definitions to clarify the metric or make it more meaningful. The E-ISAC and BESSMWG are continuing to consider new security metrics that may be useful to the industry.

Purpose

For many years now, NERC and the electricity industry have taken actions to address cyber and physical security risks to the BPS as a result of potential and real threats, vulnerabilities, and events. These security metrics complement other NERC reliability performance metrics by defining lagging and leading indicators for security performance as they relate to reliable BPS operation. These metrics help inform senior executives in the electricity industry (e.g., NERC's Board of Trustees, management, the Member Representatives Committee, and the RISC) by providing a global and industry-level view of how security risks are evolving and indicating the extent the electricity industry is successfully managing these risks. Due to the vast array of different operations technology systems used by individual electricity entities, the BESSMWG has not developed cyber security metrics applicable to the day-to-day operation of individual entities

NERC Alert Process and Security Incidents During 2016

One of the responsibilities of the E-ISAC is to provide subject matter expertise to issue security-related threat alerts, warnings, advisories, notices, and vulnerability assessments to the industry. While these alerts may provide some indication of the relative risks facing the electricity industry, they have so far not occurred frequently enough to indicate trends.

During 2016, NERC issued two industry-wide alerts[167] and one industry advisory that described large-scale distributed denial-of-service attacks, an increasing presence of ransomware, and the cyber attack that affected a portion of Ukraine's electricity system. The following summarizes the three alerts and advisories issued by NERC:

- A series of large-scale denial-of-service attacks affected a wide array of consumer internet-capable devices. While these attacks did not impact the reliable operation of the grid, they highlighted the potential vulnerability of some equipment, such as video cameras, that are widely used in the electricity industry.
- Ransomware, used to infiltrate networks and deny access to information and systems until the victim meets payment demands, continues to pose a threat as demonstrated by attacks against, for example,

[167] Ref. http://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx

hospitals and municipalities. NERC's industry advisory helped raise awareness across the industry regarding this threat.

- In December 2015, a portion of the Ukraine's electricity distribution system was disrupted by a cyber attack. The E-ISAC was involved in the post-event review, and NERC issued an alert to inform the industry and recommended actions to prevent or mitigate such an attack.

Security Performance Metrics and Results

This section provides eight security performance metrics. The E-ISAC and BESSMWG have reviewed these results and have identified trends where possible, recognizing that these results are based on only two years of data.

Security Metric 1: Reportable Cyber Security Incidents

Responsible entities must report cyber security incidents to the E-ISAC as required by the NERC Reliability Standard CIP-008-5 Incident Reporting and Response Planning. This metric reports the total number of reportable cyber security incidents[168] that occur over time and identifies how many of these incidents have resulted in a loss of load. It is important to note that any loss of load will be counted regardless of direct cause. For example, if load was shed as a result of a loss of situation awareness caused by a cyber incident affecting an entity's energy management system, the incident would be counted even though the cyber incident did not directly cause the loss of load. This metric provides the number of reportable cyber security incidents and an indication of the resilience of the BES to operate reliably and continue to serve load.

While there were no reportable cyber security incidents during 2015 and 2016, and therefore none that caused a loss of Load, this does not necessarily suggest that the risk of a cyber security incident is low, as the number of cyber security vulnerabilities is continuing to increase (ref. security metric 5).[169]

Cyber Security Incident Case Study: Ukraine

In December 2015, Ukraine fell victim to a cyber attack that included spear phishing, credential harvesting and lateral movement, unauthorized remote access, telephony denial of service, and sustaining persistent access. In February 2016, the E-ISAC provided subject matter expertise to develop the NERC alert *Mitigating Adversarial Manipulation of Industrial Control Systems as Evidenced by Recent International Events*[170], which shared techniques observed in the Ukraine cyber attacks. Most of these same tactics and techniques were used in a subsequent series of attacks against Ukraine in December 2016, when Ukraine's state-owned national power company Ukrenergo experienced an outage at an electrical substation in the capital city of Kyiv. Service was restored as a result of manual operator intervention. Researchers confirmed that the outage was the result of a cyber attack that occurred during the end of a protracted campaign.

In addition to the 2016 NERC Alert, the E-ISAC worked with SANS to publish a *Ukraine Defense Use Case*[171] (*DUC*). This 29-page report "summarizes important learning points and presents several mitigation ideas based on publicly available information on ICS incidents in Ukraine."

The techniques used against Ukraine have several options for remediation and prevention. NERC, through standards and compliance; and the E-ISAC, through information sharing, industry collaboration, and publications like the alert and DUC, often stresses and shares these remediation and prevention tips with the international electricity industry.

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[168] Ref. NERC Glossary of Terms: "A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity."

[169] ERO Reliability Risk Priorities, RISC Recommendations to the NERC Board of Trustees, November 2016, p. 9 Risk Mapping chart depicts Cyber Security Risk as having high potential impact and relative likelihood of BPS-wide occurrence.

[170] The alert is not publicly available.

[171] https://ics.sans.org/media/E-ISAC_SANS_Ukraine_DUC_5.pdf

The events in Ukraine underscore the importance of grid security and provide a real life example of consequences of a cyber attack on the electrical grid. The events abroad highlight the importance of user training and information sharing in order to prevent a similar attack on the North American power grid. To date, there have been zero reportable cyber security incidents resulting in loss of load (Metric 1).

Security Metric 2: Reportable Physical Security Events

Responsible Entities must report physical security events to the E-ISAC as required by the *NERC EOP-004-3 Event Reporting Reliability Standard*[172]*.* This metric reports the total number of physical security reportable events[173] that occur over time and identifies how many of these events have resulted in a loss of load. It is important to note that any loss of load is counted regardless of direct cause. For example, if load was shed as a result of safety concerns due to a break-in at a substation, the event is counted even though no equipment was damaged which directly caused the loss of load. The metric provides the number of physical security reportable events and an indication of the resilience of the BES to operate reliably and continue to serve load.

Note that this metric does not include physical security events reported to the E-ISAC that do not meet the reporting threshold as defined by the *NERC EOP-004-3 Reliability Standard*, such as physical threats and damage to substation perimeter fencing. Also, this metric does not include physical security events that affect equipment at the distribution level (i.e., non-BES equipment).

During 2015 and 2016, one physical security event occurred that caused a loss of load as reflected in **Figure G.1**. This near-zero result does not necessarily suggest that the risk of a physical security event causing a loss of load is low as the number of reportable events has not declined over the past two years. Although this metric does not include physical security events affecting equipment at the distribution level (i.e., non-BES equipment), NERC receives information through both mandatory and voluntary reporting that indicates that distribution-level events are more frequent than those affecting BES equipment.

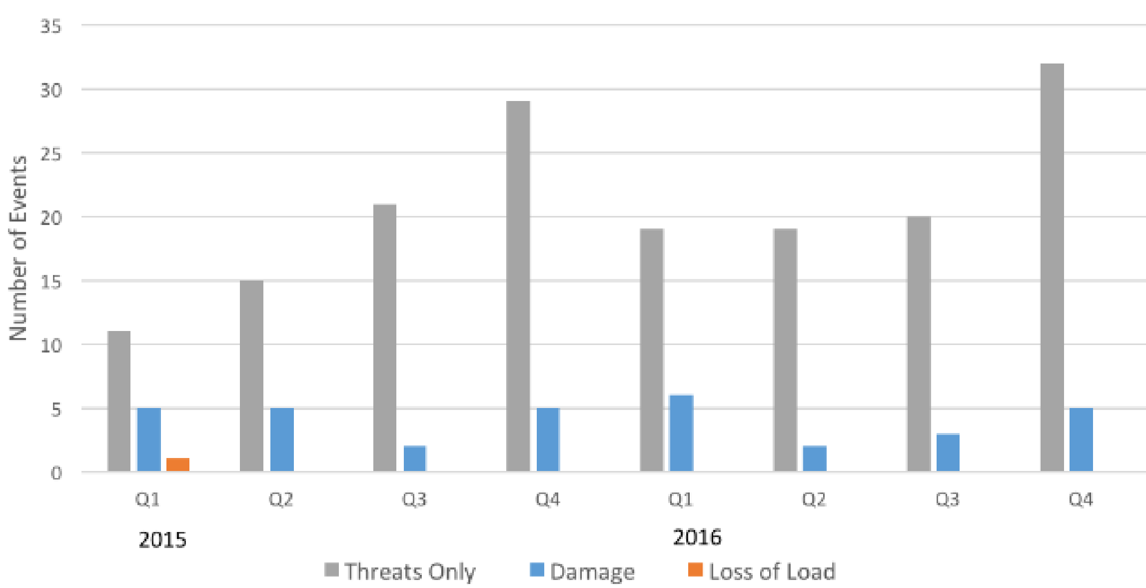

Figure G.1: Reportable Physical Security Events

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172 http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting&jurisdiction=United%20States

173 Reportable Events are defined in Reliability Standard EOP-004-2 Event Reporting, Attachment 1.

Security Metric 3: E-ISAC Membership

This metric reports the total number of electricity sector organizations and individuals registered as members of the E-ISAC. E-ISAC members include NERC registered entities and others in the electricity sector, including distribution utilities (i.e., membership is not limited to BPS organizations). Given today's rapidly changing threat environment, it is important that entities be able to quickly receive and share security-related information. This metric identifies the number of organizations registered as well as the number of individuals as depicted in **Figure G.2**. Increasing E-ISAC membership should serve to collectively increase awareness of security threats and vulnerabilities and enhance the sector's ability to respond quickly and effectively.

During the latter half of 2016, the E-ISAC implemented a password reset policy in an effort to enhance the security of its information-sharing portal by requiring members to change their passwords every 90 days and limit access to only members who actively use the portal.

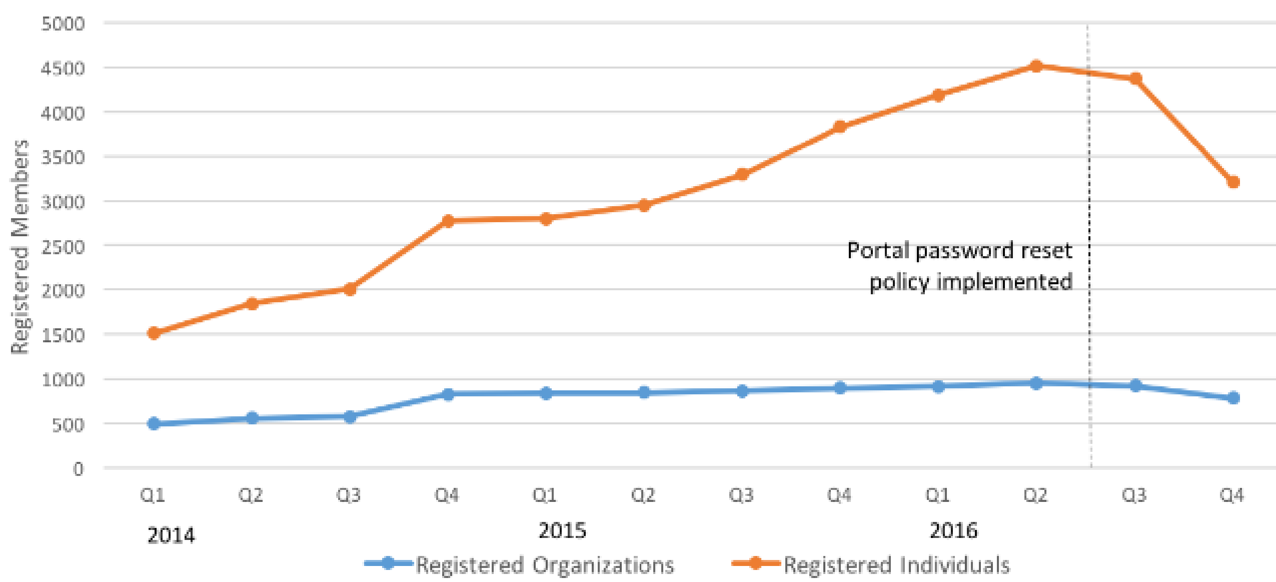

Figure G.2: E-ISAC Membership

The data indicates the following:

- As of the end of 2016, all RCs and 85 percent of Bas had an active account with the E-ISAC. As defined by the NERC functional model, RCs and Bas perform an essential coordinating role in the operation of the BPS within their respective areas and with each other.
- Since 2014, the number of registered organizations has steadily increased. However, additional outreach across the industry is needed to further increase awareness and encourage active use of the E-ISAC portal.
- The number of individual users has increased at a faster rate than the number of registered organizations. Organizations are increasing the number of individuals with access to the E-ISAC portal, likely as part of efforts to increase their security staffing capabilities and capacity.
- The E-ISAC's new portal password reset policy, implemented during 2016, has resulted in a significant decrease in the number of registered organizations and individuals. Going forward, this metric will more accurately reflect the number of members who actively use the portal as a routine part of their job.

Security Metric 4: Industry-Sourced Information Sharing

This metric reports the total number of incident bulletins (i.e., cyber bulletins and physical bulletins) published by the E-ISAC based on information voluntarily submitted by the E-ISAC member organizations as shown in **Figure**

G.3.[174] E-ISAC member organizations include NERC registered entities and others in the electricity sector, including distribution utilities (i.e., it is not limited to the BPS). Incident bulletins describe physical and cyber security incidents and provide timely, relevant, and actionable information of broad interest to the electricity sector. Given today's complex and rapidly changing threat environment, it is important that electricity sector entities share their own security-related intelligence as it may help identify emerging trends or provide an early warning to others. This metric provides an indication of the extent to which the E-ISAC member organizations are willing and able to share information related to cyber and physical security incidents they experience. As the E-ISAC member organizations increase the extent that they share their own information, all member organizations will be able to increase their own awareness and ability to respond quickly and effectively. This should enhance the resilience of the BPS to new and evolving threats and vulnerabilities. The modest but steady increase in the number of bulletins published by the E-ISAC during 2016, compared with 2015, suggests that member organizations are sharing security-related information.

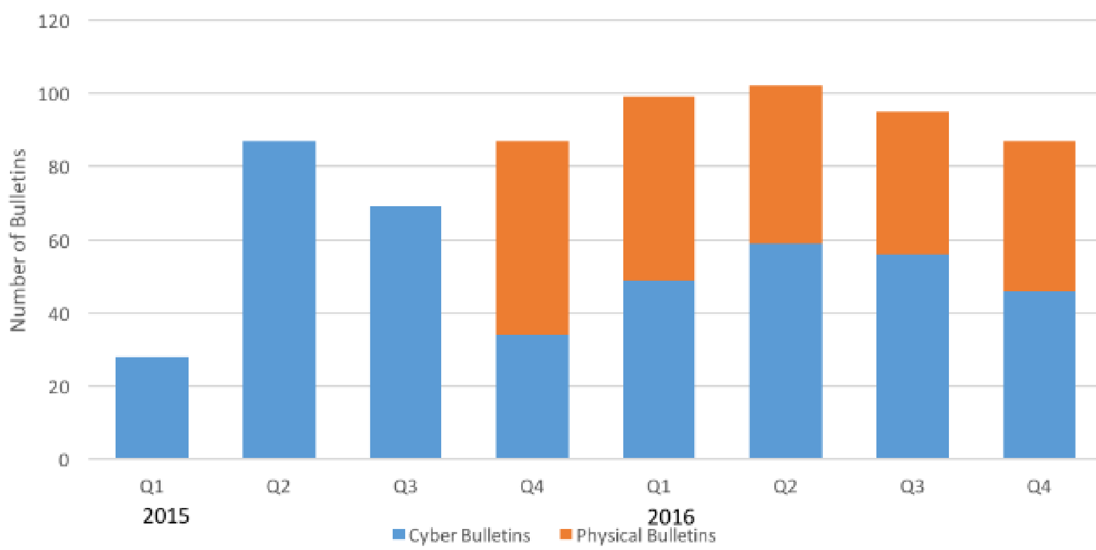

Figure G.3: Industry-Sourced Information Sharing

Security Metric 5: Cyber Security Risk Information Sharing Program Reporting Statistics

CRISP is a public-private partnership cofounded by the DOE and NERC and managed by the E-ISAC that facilitates the exchange of detailed cyber security information among industry, the E-ISAC, DOE, and Pacific Northwest National Laboratory. The program facilitates information sharing and enables owners and operators to better protect their networks from sophisticated cyber threats.

Participation in the program is voluntary and enables owners and operators to better protect their networks from sophisticated cyber threats. The purpose of CRISP is to collaborate with energy sector partners to facilitate the timely bi-directional sharing of unclassified and classified threat information. CRISP information helps support development of situational awareness tools to enhance the sector's ability to identify, prioritize, and coordinate the protection of its critical infrastructure and key resources.

CRISP participant companies serve approximately 75 percent of electricity consumers in the United States. The quantity, quality, and timeliness of the CRISP information exchange allows the industry to better protect itself against cyber threats and to make the BPS more resilient.

[174] In September 2015, the E-ISAC launched its new portal. Watchlist Entries are now called Cyber Bulletins. The category Physical Bulletins is on the portal to share physical security information. Prior to 2015 Q4, physical security reports were shared through the E-ISAC Weekly Report, but not through Watchlist Entries.

In 2016, CRISP identified intrusion methods used by threat actors with a wide variety of technical prowess and continued to identify and monitor activities of threat actors and their escalating risk to the U.S. electricity industry.

In 2016, the E-ISAC saw 41 cases predicated on IOCs provided by CRISP participants that resulted in all-site reports. CRISP all-site reports leverage ISD data and all-source intelligence to provide actionable information to support security operations across the CRISP community with company-specific information removed. **Table G.1** details the reporting statistics for 2016.

Table G.1: CRISP 2016 Reporting Statistics

Product	2016 Total
Cases Opened	1,553
Analyst Generated Reports	194
Site Annexes	442
Automated Reports	~165,000

Security Metric 6: Global Cyber Vulnerabilities

This metric reports the number of global cyber security vulnerabilities considered to be high severity (as reflected in **Figure G.4**) based on data published by the National Institute of Standards and Technology (NIST). NIST defines high severity vulnerabilities as those with a common vulnerability scoring system[175] (CVSS) of seven or higher. The term "global" is an important distinction as this metric is not limited to information technology typically used by electricity sector entities. The year-over-year increase in global cyber security vulnerabilities (23 percent) compared with global cyber security incidents (38 percent) indicates that vulnerabilities are increasingly being successfully exploited, and reinforces the need for organizations to continue to enhance their cyber security capabilities.

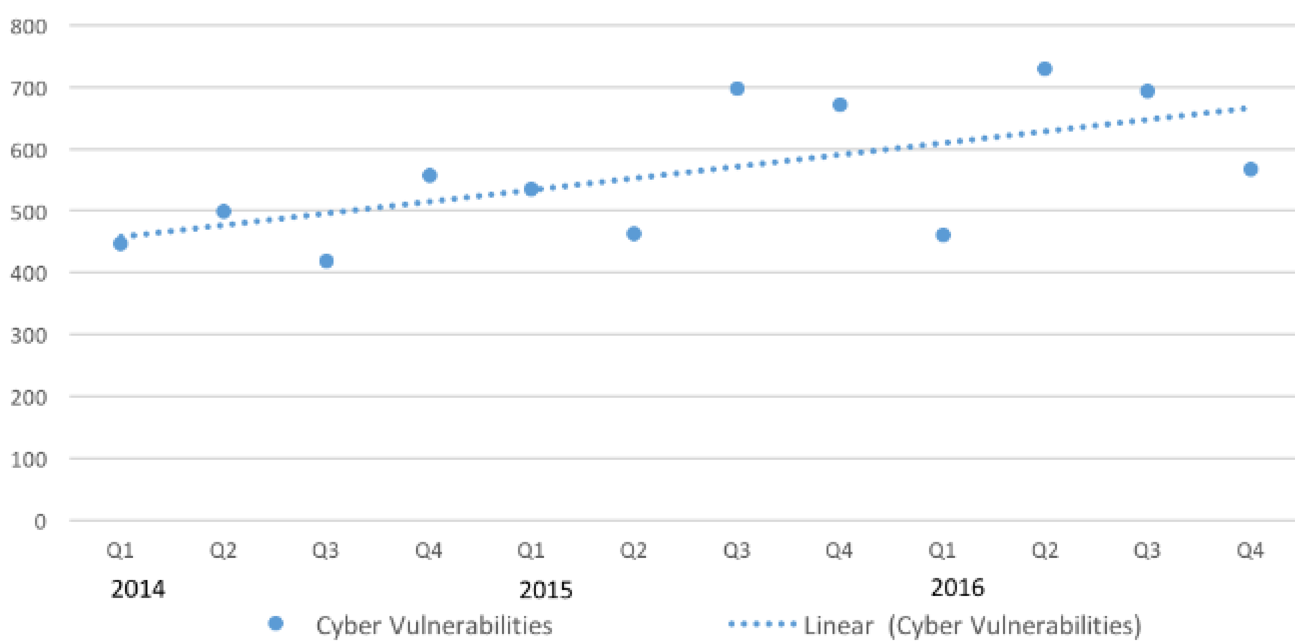

Figure G.4: Global Cyber Vulnerabilities

[175] Ref. NIST http://nvd.nist.gov/cvss.cfm

Security Metric 7: Global Cyber Vulnerabilities and Incidents

This metric compares the number of annual global cyber security vulnerabilities and incidents to identify a possible correlation between them as illustrated in **Figure G.5**. This metric is based on surveys of chief information technology officers and chief information security officers, and although the survey respondents change from year to year, reports of this nature tend to have consistent results and will continue to be a valid indicator. While many different sources for this information are publicly available, the BESSMWG had selected the PwC Global State of Information Security report because it had consistently reported the number of incidents since at least 2013. Unfortunately, PWC did not provide the data for 2016; the BESSMWG is working to determine if this information will be available in future. If not, the BESSMWG will seek alternate sources for similar data.

Figure G.5: Global Vulnerabilities versus Incidents

Security Metric 8: GridEx Exercise Participation

This metric compares the number of organizations participating in each of the GridEx security and crisis response exercises conducted by NERC every two years as shown in **Figure G.6**. NERC's large-scale GridEx exercises provide electricity organizations with the opportunity to respond to simulated cyber and physical security attacks affecting the reliable operation of the North American grid.

Increasing participation rates indicate the extent to which organizations consider the evolving GridEx program to be a valuable learning opportunity. Increasing participation may indicate the extent to which the electricity industry as a whole is ready to respond to a real cyber or physical attack. The metric distinguishes between "active" and "observing" organizations. Active organizations participate by assigning staff to participate in the exercise from their work locations at control centers or power plants as if it were a real event. Observing organizations participate in a more limited way, typically through an internal tabletop exercise. The metric shows a significant increase in total numbers of participating electricity organizations and an increasing proportion of active organizations.

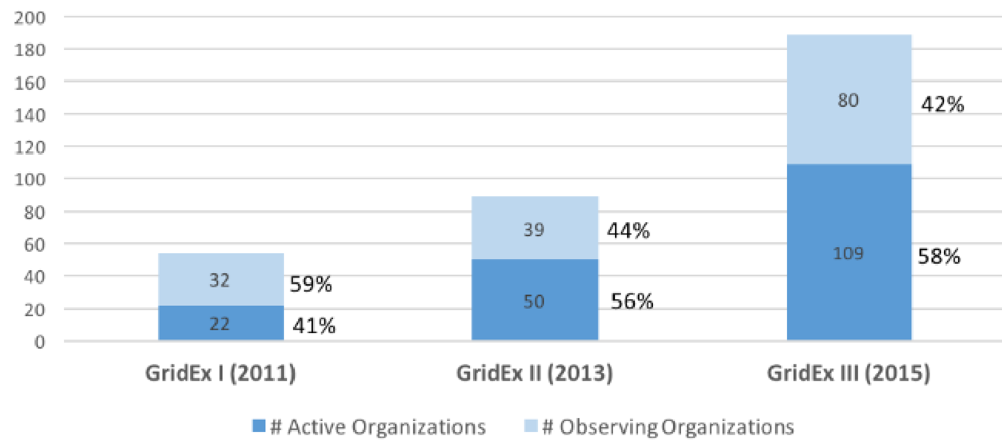

Figure G.6: GridEx Participants

Roadmap for Future Metrics Development

The BESSMWG and the E-ISAC have developed a roadmap for future metrics development, including refining the initial set of metrics that are based on operational experience. The roadmap addresses consideration of the challenges associated with collecting security-related data:

- Historically, NERC and the E-ISAC have limited data related to cyber and physical security incidents as these incidents have been relatively rare and have had little or no impact on BPS reliability.
- Nobody yet knows the magnitude or number of constantly changing security threats and vulnerabilities with any degree of certainty, particularly as they relate to BPS reliability.
- The number and type of cyber systems and equipment used by the industry is vast, making it difficult to develop metrics that are meaningful to individual entities across the industry.
- Data that details security threats, vulnerabilities, and real incidents is highly sensitive. Handled inappropriately, this can expose vulnerabilities and encourage adversaries to develop new and more sophisticated exploits.

The BESSMWG has researched security metrics developed by leading experts outside the electricity industry and examined over 150 of these to assess their applicability from a BPS reliability perspective. Out of these 150 metrics, the BESSMWG concluded that about 30 would be relevant. This assessment underscores the challenges associated with developing relevant and useful security metrics that rely on data willingly and ably provided by individual entities. The BESSMWG will continue to investigate potential new physical and cyber security metrics.

Two particular areas stand out for further study during 2017:

- The extent to which the industry uses automated communications methods[176] to share cyber security information between individual organizations and the E-ISAC.
- While global cyber security vulnerabilities and incidents provide a very high-level view of threats facing the industry, a more relevant metric for the industry would focus on EMS and SCADA commonly used by the electricity industry.

[176] For example, CRISP uses information sharing devices to collect and transmit security information from electricity operator participant sites. Data is shared with CRISP participants, and unattributed data is shared with the broader E-ISAC membership. For organizations not participating in the CRISP program, TAXII, STIX, and CybOX are community-driven technical specifications designed to enable automated information sharing for cyber security situational awareness, real-time network defense, and sophisticated threat analysis. These methodologies are international in scope and free for public use.

Appendix H: Abbreviations Used in This Report

Acronym	Description
AC	Alternating Current
ACE	Area Control Error
ACSETF	AC Substation Equipment Task Force
AESO	Alberta Electric System Operator
ALR	Adequate Level of Reliability
ANOVA	Analysis of Variance
AOO	Asset Owners and Operators
APC	Element Availability Percentage
BA	Balancing Authority
BAL	Resource and Demand Balancing
Bcf	Billion cubic feet
BES	Bulk Electric System
BESSMWG	BES Security Metrics Working Group
BPS	Bulk Power System
BPSA	Bulk Power System Awareness
CAISO	California Independent System Operator
CAISS	Cyber Automated Information Sharing System
CAP	Corrective Action Plan
CAT	Category
CCC	Compliance and Certification Committee
CDM	Common/Dependent Mode
CEATI	Centre for Energy Advancement through Technical Innovation
CIP	Critical Infrastructure Protection
CIPC	Critical Infrastructure Protection Committee
CP-1	Compliance Process-1
CP-2	Compliance Process-2
CRISP	Cybersecurity Risk Information Sharing Program
CVSS	Common Vulnerability Scoring System
DADS	Demand Response Availability Data System
DADSWG	Demand Response Availability Data System Working Group
DCS	Disturbance Control Standard
DDoS	Distributed Denial-of-Service
DER	Distributed Energy Resources
DERTF	Distributed Energy Resources Task Force
DHS	Department of Homeland Security
DNS	Domain Name System
DOE	Department of Energy
DP	Distribution Provider
DR	Demand Response
DUC	Defense Use Case
EA	Event Analysis
EAR	Event Analysis report
EAS	Event Analysis Subcommittee
EEA	Energy Emergency Alert
EFOR	Equivalent Forced Outage Rate

Acronym	Description
EFORd	Equivalent Forced Outage Rate – demand
EI	Eastern Interconnection
E-ISAC	Electricity Information Sharing and Analysis Center
EMS	Energy Management Systems
EMSWG	Energy Management System Working Group
EOP	Emergency Operations
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ERS	Essential Reliability Services
ERSWG	Essential Reliability Service Working Group
ESCC	Electricity Subsector Coordinating Council
eSRI	Event Severity Risk Index
EU	European Union
FACTS	Flexible Alternating Current Transmission Systems
FBI	Federal Bureau of Investigation
FERC	Federal Energy Regulatory Commission
FR	Frequency Response
FRCC	Florida Reliability Coordinating Council
FWG	Frequency Working Group
GADS	Generating Availability Data System
GADSWG	Generating Availability Data System Working Group
GO	Generator Owner
GOP	Generator Operator
GridEx	Grid Exercise
HP	Human Performance
Hz	Hertz
ICC	Initiating Cause Code
ICS	Industrial Control System
ICS-CERT	Industrial Control Systems Cyber Emergency Response Team
IFRO	Interconnection Frequency Response Obligation
IOC	Indicators of Compromise
IoT	Internet of Things
IROL	Interconnection Reliability Operating Limit
ISAC	Information Sharing and Analysis Centers
ISO	Independent System Operator
ISO-NE	ISO New England
IT	Information Technology
JAR	Joint Analysis Report
KCMI	Key Compliance Monitoring Index
LTRA	Long Term Reliability Assessment
MEC	Member Executive Committee
MEITF	Methods of Establishing IROLs Task Force
MEPS	Member Engagement, Products, and Services
MRO	Midwest Reliability Organization
MSSC	Most Severe Single Contingency
MVA	Mega Volt Ampere

Acronym	Description
MW	megawatt
MWh	megawatt hour
NAGF	North American Generator Forum
NATF	North American Transmission Forum
NCCIC	National Cybersecurity and Communications Integration Center
NCI	National Council of ISACs
NCIRP	National Cyber Incident Response Plan
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NOI	Notice of Inquiry
NOP	Notice of Penalty
NOPR	Notice of Proposed Rulemaking
NPCC	Northeast Power Coordinating Council
NYISO	New York Independent Service Operator
OC	Operating Committee
OE	Office of Electricity Delivery and Energy Reliability
OTT	Operations, Tools, and Technologies
OY	Operating Year
PAS	Performance Analysis Subcommittee
PC	Planning Committee
PCS	Protection and Controls Subcommittee (SERC)
PNNL	Pacific Northwest National Laboratory
PRC	Protection and Control
PRS	Protective Relay Subcommittee
PwC	PricewaterhouseCoopers LLC
QI	Québec Interconnection
RAS	Remedial Action Scheme
RC	Reliability Coordinator
RCIS	Reliability Coordinator Information System
RE	Regional Entities
RF	ReliabilityFirst
RISC	Reliability Issues Steering Committee
RPS	Renewable Portfolio Standard
RS	Resources Subcommittee
RSG	Reserve Sharing Group
RTO	Regional Transmission Organization
SAMS	System Analysis and Modeling Subcommittee
SANS	System Administration, Networking, and Security
SAS	Statistical Analysis System
SCC	Sustained Cause Code
SERC	SERC Reliability Corporation
SNL	Sandia National Laboratories
SOL	System Operating Limit
SPCS	System Protection and Control Subcommittee (NERC)
SPCWG	System Protection & Control Working Group (SPP)
SPOD	Single Point of Disruption
SPP-RE	Southwest Power Pool Regional Entity

Acronym	Description
SPS	Special Protection Schemes
SPWG	System Protection Working Group (TRE)
SRI	Severity Risk Index
SS	Statistically Significant
SVC	Static Var Compensators
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
Texas RE	Texas Reliability Entity
TOP	Transmission Operators
TOS	Transmission Outage Severity
UFLS	Underfrequency Load Shed
WECC	Western Electricity Coordinating Council
WEFOR	Weighted Equivalent Forced Outage Rate
WI	Western Interconnection

Appendix I: Contributions

NERC would like to express its appreciation to the many people who provided technical support and identified areas for improvement. These include the NERC Industry Groups in **Table H.1**, Contributing Regional Staff in **Table H.2**, and NERC Staff in **Table H.3**.

Table H.1: NERC Industry Group Acknowledgements	
Group	**Officers**
Planning Committee Reviewers	Chair: David Weaver, Peco Energy Vice Chair: Brian Evans-Mongeon, Utility Services, Inc. Gary Brownfield, Ameren Services Phil Fedora, NPCC Michael Goggin, American Wind Energy Association Wayne Guttormson, Sask Power David Mercado, Center Point Energy Katy Onnen, Kansas City Power and Light Russell Schussler, Georgia Transmission Branden Sudduth, WECC Carl Turner, Florida Municipal Power Agency Brian Van Gheem, ACES
Operating Committee Reviewers	Chair: Jim Case, Entergy Vice Chair: Lloyd Linke, WAPA Peter Brandien, ISO-New England Alan Bern, Oncor Stuart Goza, TVA Hassan Hamdar, FRCC Jeffrey Harrison, Associated Electric Cooperative Inc. Sydney Jackson, Rochester Public Utilities Michelle Rheault, Manitoba Hydro Sammy Roberts, Duke Energy David Zwergel, MISO
Critical Infrastructure Protection Committee Reviewers	Chair: Marc Child, Great River Energy Vice Chair: Nathan Mitchell, APPA Vice Chair: David Revill, GTC
Bulk Electric System Security Metrics Working Group (BESSMWG)	Chair: Larry Bugh, Reliability First
Performance Analysis Subcommittee	Chair: Paul Kure, ReliabilityFirst Vice Chair: Maggie Peacock, WECC State of Reliability Report Lead: John Seidel, MRO Statistical & SRI Support: Heide Caswell, PacifiCorp
Demand Response Availability Data System Working Group	Chair: Bob Reynolds, SPP RE Vice Chair: Joe Ballantine, ISO-New England
Events Analysis Subcommittee	Chair: Hassan Hamdar, FRCC Vice Chair: Rich Hydzik, Avista Corporation
Generation Availability Data System Working Group	Chair: Leeth DePriest, Southern Company Vice Chair: Steve Wenke, Avista Corporation Additional Support: Ron Fluegge, GADSOS
Transmission Availability Data System Working Group	Chair: Kurt Weisman, ATC Vice Chair: Brian Starling, Dominion

Table H.1: NERC Industry Group Acknowledgements	
Resources Subcommittee	Chair: Troy Blalock, SCE&G Vice Chair: Tim Reynolds, WECC
Operating Reliability Subcommittee	Chair: Eric Senkowicz, FRCC Vice Chair: Dave Devereaux, IESO
Frequency Working Group	Chair: Tony Nguyen, BC Hydro
Reliability Assessment Subcommittee	Chair: Phil Fedora, NPCC Vice Chair: Tim Fryfogle, Reliability First
System Protection and Control Subcommittee	Chair: Rich Quest, Midwest Reliability Org Vice Chair: Mark Gutzmann, Xcel Energy
Compliance and Certification Committee	Chair: Patricia E. Metro, NRECA Vice Chair: Jennifer Flandermeyer, KCP&L

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Exhibit 5

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERO Reliability Risk Priorities

RISC Recommendations to the NERC Board of Trustees

November 2016

RELIABILITY | ACCOUNTABILITY

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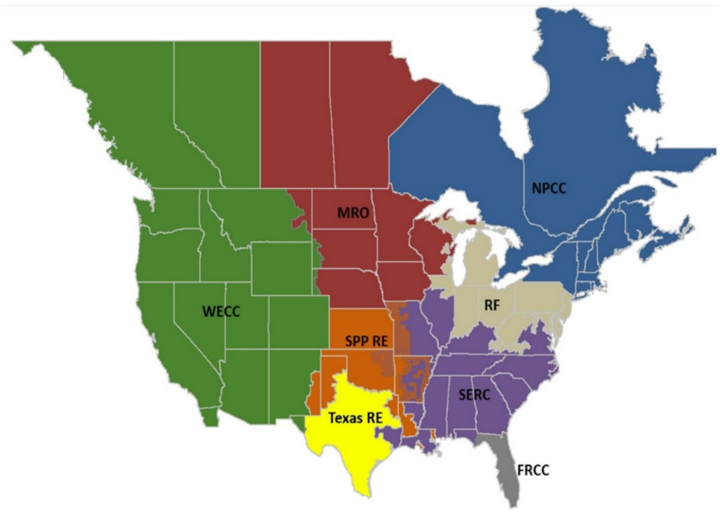
Table of Contents

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 eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

The Reliability Issues Steering Committee (RISC) is an advisory committee to the NERC Board of Trustees (Board). The RISC provides key insights, priorities, and high-level leadership for issues of strategic importance to BPS reliability. The RISC advises the Board, NERC standing committees, NERC staff, regulators, REs, and industry stakeholders to establish a common understanding of the scope, priority, and goals for the development of solutions to address emerging reliability issues. The RISC provides guidance to the ERO Enterprise and the industry to effectively focus resources on the critical issues to improve the reliability of the BPS.

This 2016 report presents the results of the RISC's continued work to strategically define and prioritize risks to the reliable operation of the BPS and thereby provide recommendations to the Board regarding the approach that NERC should take to enhance reliability and manage those risks.

Chapter 1: Background and Introduction

Background

This 2016 annual report documents the results of the RISC's continued work to identify key risks to the reliable operation of the BPS. This report proposes relative priorities and management effort pacing and provides input to the Board on recommended actions.

The RISC's obligations are based on the NERC Board's resolutions on the initial 2013 recommendations:

> *RESOLVED, that the Board hereby accepts the report of the Reliability Issues Steering Committee (RISC), expresses its appreciation to the RISC for the excellent report, and endorses continued work by the RISC on a gap analysis on the high-priority and then the medium-priority issues and requests continued reports to the Board.*
>
> *FURTHER RESOLVED, that the Board hereby directs NERC management to continue to work with the RISC to consider how the priority rankings should be reflected in the development of the ERO's business plan and in the work plans of NERC committees.*
>
> *FURTHER RESOLVED, the Board hereby directs NERC management to work with the RISC and, as appropriate, NERC committee leadership to consider how NERC should utilize a data-driven reliability strategy development process that integrates with budget development and overall ERO planning (e.g., Standing Committee planning, department, and employee goal-setting).*

There are important links between the risk priorities and the recommended actions for the ERO Enterprise and industry. The RISC acknowledges and appreciates the increased reliance of the NERC Board and ERO Enterprise leadership on this report as an input for the ERO's multiyear Strategic Plan and its Business Plan and Budget.

The RISC participants include representatives from the NERC standing committees, the Member Representatives Committee (MRC), and "at large" industry executives. The observations, findings, and guidance presented in this report include input from industry forums, trade associations, and other industry groups. RISC also received feedback through policy input to the NERC Board of Trustees and an industry webinar.

The 2016 report builds on the comprehensive initial assessment of ongoing efforts and corresponding recommendations to the Board made in February 2013, which have been updated and refined annually. This report and recommendations reflect discussions with representatives from technical and standards committees, industry dialogue through a series of focused executive leadership interviews, the FERC Reliability Technical Conference, and technical reports and assessments. These results were presented to the ERO executive management group for integration in the development of the 2017–2020 ERO Enterprise Strategic Plan. The final report will be presented to the Board in November 2016.

Introduction

The RISC has carefully reviewed numerous inputs on BPS reliability from various stakeholders, and this report reflects the top priorities of the industry leadership represented on the committee. The RISC reviewed and assembled information from ERO Enterprise[1] stakeholders, policy makers,[2] and focused executive leadership interviews to develop a composite set of risk profiles and a graphic depiction of the key risks to the system. The

[1] ERO Enterprise is interpreted to mean NERC, the Regional Entities, and the necessary technical committees.

[2] Policy makers is interpreted to mean any entity that can impact the legal or regulatory framework in place at various levels, including local, state, federal, and provincial governmental authorities in addition to various trades and lobbying organizations.

depiction presents the likelihood of occurrence, the expected impact on reliability, and the trajectory of the associated risks.

The individual risk profiles have been categorized as High, Moderate, or Low. High-risk profiles present not only a possible severe impact on reliability but also a level of uncertainty. The High risks are evolving and the likely impact and necessary mitigation are often less clear. Thus, High risks require a larger amount of industry attention and resource focus to better understand and address impacts to the system. Moderate risks still represent a large potential impact to the BPS, but there is consensus that the industry understands the risk and necessary steps to improve reliability. Low risks do not mean that possible reliability impact is small, but rather the profiles are understood with clearly identifiable steps that can be taken to manage risk. Thus, even risks that are well understood and have measures in place for risk mitigation are included as risk profiles because the industry must remain vigilant in addressing these Lower or Moderate risks in order to prevent the profiles from being escalated higher.

A Low or Moderate ranking in this report does not mean the risk covered in the profile is not a threat to the system. These risks still require monitoring and action to mitigate or reduce the likelihood of instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the BPS. Accordingly, the risk profiles were categorized as follows:

High Risk Profiles

- Cybersecurity Vulnerabilities
- Changing Resource Mix
- BPS Planning
- Resource Adequacy

Moderate Risk Profiles

- Loss of Situational Awareness
- Physical Security Vulnerabilities
- Extreme Natural Events

Low Risk Profiles

- Asset Management and Maintenance
- Human Performance and Skilled Workforce

Format of the Report and Method of Analysis

A majority of this report is comprised of risk profiles that detail the evolving status and mitigation efforts to address each specific risk. These profiles outline a summary of the risks and the potential impact to the BPS. Through the profiles, the RISC recommends activities to manage the risks in the near-term, mid-term, and long-term. The ERO Enterprise and industry can use the composite risk profiles and the risk map for baseline and recurring evaluation of reliability risks.

Where appropriate, the RISC identified the group or entity that should take mitigating action; however, some recommendations did not present a clear owner or responsible party. In these cases, the recommendation is presented as a more generalized action item that can apply to numerous entities, including policy makers, industry, and the various organizations in the ERO Enterprise.

The primary objective of this report is to highlight risks that merit a continued level of attention and recommended actions that align with the multidimensional aspects of the risk. This report differs from other ERO reports, such as the annual *State of Reliability,* in that it is forward-looking view of the BPS. The *State of Reliability* reviews data from previous years to draw objective conclusions.

Additionally, the committee evaluated risks based on impact to the BPS regardless of the source of the risk. In order to evaluate key risks to the system, the committee had to recognize various emerging issues in different areas of the grid and resources such as distributed energy resources. Operators and planners of the BPS are aware of the need to have a wide-area view to provide an understanding of external conditions that can affect them; therefore, the profiles note several risks where the BPS can be impacted at interfaces (*e.g.,* distributed resources, gas delivery, telecom, etc.). RISC determined it is important to shine a light on external factors that increase BPS risk and offered recommendations to address them. Given the changing nature of the system and acceleration of integrating distributed energy resources, the RISC is obligated to raise areas of concern since impacts from distributed resources may require mitigations at the BPS level.

Other inputs to the Risk Profiles

FERC Technical Conference

On June 1, 2016, FERC conducted a commissioner-led technical conference on reliability. The purpose of the conference was to discuss policy issues related to the reliability of the BPS. As part of its review of emerging risks to the reliable operation of the BPS, RISC used the inputs and active discussions at this conference to supplement its development of the risk profiles. The technical conference addressed three main topics: the 2016 State of Reliability, Emerging Issues, and Grid Security. These topics were addressed in four panel sessions:

- The first panel focused on the **2016 State of Reliability.** The participants of this panel affirmed several of the risks identified by the RISC. The panelist identified the most significant risks to the BPS as coordinated physical attacks on the system, interdependencies from other industries, extreme weather events, gas dependency, adequacy of models (past N-1), and aging infrastructure. This panel also highlighted necessary actions to address the adequacy and modeling of the distribution system. Panelists discussed the need for better modeling and increased visibility of the system. In addition, panelists noted a need to identify the difference between the distribution and transmission operator responsibilities.
- The second topic, **Emerging Issues,** was divided into two panels. The first panel provided an international perspective to the grid's emerging issues, and panelists from the European Union and Mexico added several perspectives. Market features were discussed that could improve reliability, such as protocols for buying capacity and markets designed around a reliability objective. The second panel continued the first panel's discussion on emerging trends and risks, but concentrated the discussion on distributed resources, vulnerability to natural gas fuel deliverability, and microgrids. The rapid acceleration of the changing resource mix and need to identity metrics around essential reliability services (ERS) was discussed. Additionally, the reliability concerns from the Aliso Canyon natural gas leak exemplified the challenges in the West. This panel stressed the need for better planning and the need for flexibility in order to mitigate risks from the changing resource mix.
- The final panel, addressing **Grid Security,** highlighted the need to share threat information and to support industry coordination. In addition, the need to develop a culture of cyber-awareness among the workforce was identified along with the suggestion the industry could invest in neutral ground-blocking devices.

Pulse Point Interviews

In order to expand the consideration of potential reliability risks from a strategic perspective, the RISC conducted one-on-one interviews with key industry executives and leaders to gain their insight. The goal was to focus on important reliability risks from different vantage points among regulators and utilities and to ensure that key areas of reliability concern and relevant priorities were adequately identified for consideration by the RISC. A summary of these interviews are described below.

Several interviews validated the concerns presented in the risk profiles. The profiles of Changing Resource Mix and Cybersecurity Vulnerabilities were the most common themes in all of the interviews. In addition, several industry executives voiced concerns over fuel dependency and the greater reliance on natural gas. Many utilities commented that natural gas currently serves as the baseload fuel for their areas, heightening the need for greater focus on gas infrastructure in order to identify potential risks to the BPS.

Although several industry leaders acknowledged that NERC has no jurisdiction over markets, there is a growing concern that the existing markets do not accurately reflect products necessary to support the new resources being integrated today. For example, several markets may not include ancillary services necessary to support reliability when relying on more distributed resources. Several executives also expressed concern over the current rate structure where large investments to augment or maintain the system are precluded.

A continued theme from 2015 is some leaders are concerned about a workforce shortage, such as protection and control engineers. The aging workforce has been a consistent theme throughout the years, and some leaders provided support for continuing to monitor this risk.

A few leaders encouraged the ERO to place a stronger emphasis on the electro-magnetic pulse (EMP) threat, particularly with high altitude devices capable of causing widespread outages. Also one leader suggested changing the focus to constructing a more resilient distribution system to support reliability as more renewables and other resources are being added to the distribution system.

The following list identifies recommendations provided during the pulse point interviews. Policy makers should recognize the need to support the costs needed to manage, operate, and maintain system assets as these activities are part of an organization’s ability to maintain and improve system performance and the reliable operation of the power system.

- The industry and the ERO Enterprise should collect more detailed data from larger areas (“bigger data”) to support better analytics and larger studies.
- The industry should consider updating studies and not rely on just N-1 scenarios. This may entail fully studying the distribution system.
- RTOs/ISOs should consider studies beyond three years out in order to assess certain reliability needs.
- Expedite research and development to bring advancements to market sooner, specifically fuel and energy storage and fuel cell technology.
- Entities should have a clear communication protocol both internally and externally in the event of coordinated attacks or coincident events.
- Entities should begin considering how to build a new generation of back-up systems for natural disasters and extreme events.
- The industry must expand or introduce a true “security culture” to small electric utilities.
- The industry should collaborate on a common software platform for distribution management systems.

Focus Areas and Recommendations from the Risk Profiles

Outlined here are the highest priority focus areas identified in the 2016 risk profiles. Concentrated effort by the Industry on these areas, as well as inclusion of goals within the ERO Strategic Plan and the associated Business Plan and Budget, should improve BPS reliability. Additional detail can be found in the associated Risk Profiles.

Cybersecurity Vulnerabilities (Risk Profile #9)

- The ERO Enterprise and the industry should adopt a nimble, multipronged approach to address the continually evolving cybersecurity threat. Examples of nimble tools include increased Electricity information sharing and analysis centers (E-ISAC) participation and products, peer reviews and assistance visits to move to a best-practice model, and guides and recommendations for new and less-defined threats.
- The E-ISAC, the Telecommunications, and Natural Gas Information Sharing and Analysis Centers should enhance communications. Expand the use, availability, and value of cybersecurity threat and vulnerability information sharing, analytics, and analysis.
- The ERO Enterprise and all utilities should foster development of a security culture among their employees.

Changing Resource Mix (Risk Profile #1)

- The ERO Enterprise should:
  - Assess the risks associated with single points of disruption of natural gas as well as the uncertainty of supply.
  - Use special assessments and studies to inform and educate policy makers, regulators, and the industry of reliability effects and interconnection requirements.
  - Gather data and insights on distributed energy resources in an effort to improve visibility, predictability, and the dispatchability needed to support BPS reliability.
  - Continue to provide independent technical assessments on reliability issues stemming from proposed regulatory rules or statutes as well as any significant tariff rules related to the changing resource mix.
  - Further develop lessons learned based on operational experience with variable energy and distributed energy resources.
- To address the impact on ERS, NERC should benchmark and support technical studies on frequency and inertia response, voltage support, short-circuit analysis, and inter-area oscillations.

BPS Planning (Risk Profile #2)

- The ERO Enterprise should:
  - Coordinate with the industry, manufacturers and developers of asynchronous resources to develop and make available accurate dynamic models.
  - Identify the type and frequency of information needed from distributed energy resources.
  - Create guidelines and best practices for developing and maintaining accurate system, dynamic and electromagnetic models that include transmission, resources, load, and controllable devices for use in long-term and operational planning.
  - Continue to assess ERS performance to develop necessary guidelines and to determine if Reliability Standards are required.

- NERC should continue to collaborate with Planning Coordinators to expand development of interconnection-wide models commensurate with expected dispatches. This collaboration will support the ability to conduct more effective long-term planning assessments.

Resource Adequacy and Performance (Risk Profile #3)

- The ERO Enterprise should:
  - Continue to improve modeling and probabilistic methods with industry to evaluate resource adequacy to include impacts from ERS, unit retirements, and load and resource variability during different time frames (including shoulder months).
  - Assess and develop mitigation recommendations to address single points of disruption, such as fuel contingencies, that will result in large resource outages.
  - Develop new measures of reliability beyond reserve margins, including the sufficiency of ERS.
  - Continue to assess vulnerabilities of fuel availability as part of evaluating resource adequacy and operational capability.
- The industry should evaluate opportunities to develop more accurate short-term load forecast models.
- Analyze data requirements necessary to ensure there is sufficient detail on the capability and performance of the BPS as it is impacted by distributed energy resources. The industry should gather data beyond simple demand forecasts and expand to identify resource capacity, location, and ERS capability.

Themes and Takeaways from the Risk Profiles

In drafting the 2016 risk profiles, no new major risk profiles have been identified. However, several key themes from the profiles show where industry attention is needed.

Resilience and Recovery

Resilience and recovery actions can mitigate exposure from multiple risks. This is particularly important as threats to electric industry infrastructure from cyber and physical attacks are expected to increase, and customers and regulators have increasing expectations on the continuity of electric service. While this report addresses ways to address specific risks, not all possible risks can be anticipated or mitigated. Efforts and resources expended on resilience and recovery can address a wide range of risks and can also limit the extent of extreme or low-likelihood incidents. Resilience assessments in the planning and operating processes should be pursued to support BPS reliability. This was identified as a key recommendation during the 2015 Leadership Summit.

Part of the RISC's role is to identify trends and evolving issues that have the potential to degrade reliability so that actions based on sound technical judgment can be taken. As the character and reliability behavior of the BPS evolves, a wide range of reliability or resilience tools should be identified to guide industry, regulators, and the ERO in effectively managing these risks. The industry must improve forward assessments of reliability and identify resilience activities that anticipate changes.

Key points on resiliency and recovery include:

- In 2015, the top 10 most severe events were related to weather.[3] The ERO Enterprise, the impacted organizations, and the respective forums and trade organizations should perform post-event reviews to capture lessons learned and how to reduce the impact of future events.

[3] See the *State of Reliability* report.

- While the industry operates to the next worse contingency, the industry should be aggressive in identifying single points of vulnerability.
- Continue to leverage the North American Generator Forum (NAGF), North American Transmission Forum (NATF), Electric Power Research Institute (EPRI), and other industry-practice-sharing forums to enhance resilience and recovery.
- Leverage data sources such as event analysis, near miss databases, the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Demand Response Availability Data System (DADS), relay misoperations, EOP-004/OE-417 reports, and ac equipment failures to identify patterns and risks.
- Highlight applicable metrics in the *State of Reliability* report as benchmarks for resilience and recovery.
- Continue to include resilience goals in the ERO Enterprise's Strategic Plan.

The ERO Enterprise must have a complete understanding of the changing nature of, and associated risks to, the BPS. This includes a more comprehensive analysis of the BPS using NERC's special assessments. Further, markets and other tariffs will influence the changing nature of the reliability behavior of the power system and can provide the full complement of services required for the continued reliable operations of the BPS. The work on ERS is vital to understand the minimum requirements surrounding frequency response, voltage, and ramping resulting from the acceleration of the changing resource mix.

Adequate Data Visibility

Data is needed to understand the performance of and risks to the BPS. This includes information regarding distributed energy resources. Several profiles recommend the ERO Enterprise and industry use "bigger data" from multiple sources and larger areas to identify and manage risks. It is imperative that data requirements also include: 1) the data needed from distributed energy resources, including any necessary aggregated forms of data; 2) the entities should provide the data to system operators and planners; 3) logistics for how the data will be exchanged; 4) the frequency of the data updates; and 5) security and confidentiality measures for protecting necessary data.

Accurate Models

Since the rate of change of the resource mix is increasing, planners will place more emphasis on interconnection-wide studies that require improvement to and integration of regional models. In addition, enhancements to models will be needed to support probabilistic analysis to accommodate the energy limitations of resource additions (such as variable renewable resources). Resource adequacy must look beyond the calculation of reserve margins which assume actual capacity available during peak hours. More comprehensive dynamic load models will also be needed. One of the ways in which the industry can understand the system is by monitoring load characteristics and its changing nature due to distributed.

Natural Gas Deliverability

One common underlying risk that can be tied to multiple profiles is the increased use of just-in-time fuel delivery. More specifically, several profiles identify challenges from the single points of failure caused by the increased penetration of natural gas as a base load fuel. Natural gas deliverability and its impact on reliability must be fully studied to identify necessary mitigation strategies, including market, infrastructure, or regulatory solutions. The increased dependency on natural gas as a predominant fuel source presents challenges in real-time to system operators, and situational awareness must now include gas sources, pipeline, and deliverability concerns. Further, any cyber or physical attack on a pipeline highlights the need for increased coordination among pertinent information sharing and analysis centers (ISACs) and the industry to improve response and recovery times due to the interdependency of the gas and electric system. The ability to model and address fuel limitations or shortages in BPS planning is a critical part of system planning. Therefore, there is a need for improved models as well as required data and information to support this planning to ensure the continued reliable operation of the BPS.

Spare Equipment Strategy

Asset management, physical security, and extreme events highlight a need to maintain a focus on a spare equipment strategy. This strategy should encompass identifying critical spare equipment as part of a national or regional inventory. The strategy should also account for the transportation/logistics requirements for replacing critical assets. An improved spare equipment strategy or plan will lead to better planning and possibly faster response times for restoration and recovery.

Chapter 2: Discussion of Reliability Risks

NERC should continue to collaborate with Planning Coordinators to expand development of interconnection-wide models commensurate with expected dispatches. This collaboration will support the ability to conduct more effective long-term planning assessments.

Legend Guide to Figure 2.1

The solid numbered circles in the heat map denote the current state for each risk area, and they are mapped against likelihood and impact scales. The risk trend represents where the committee views the risk to be trending in the near future.

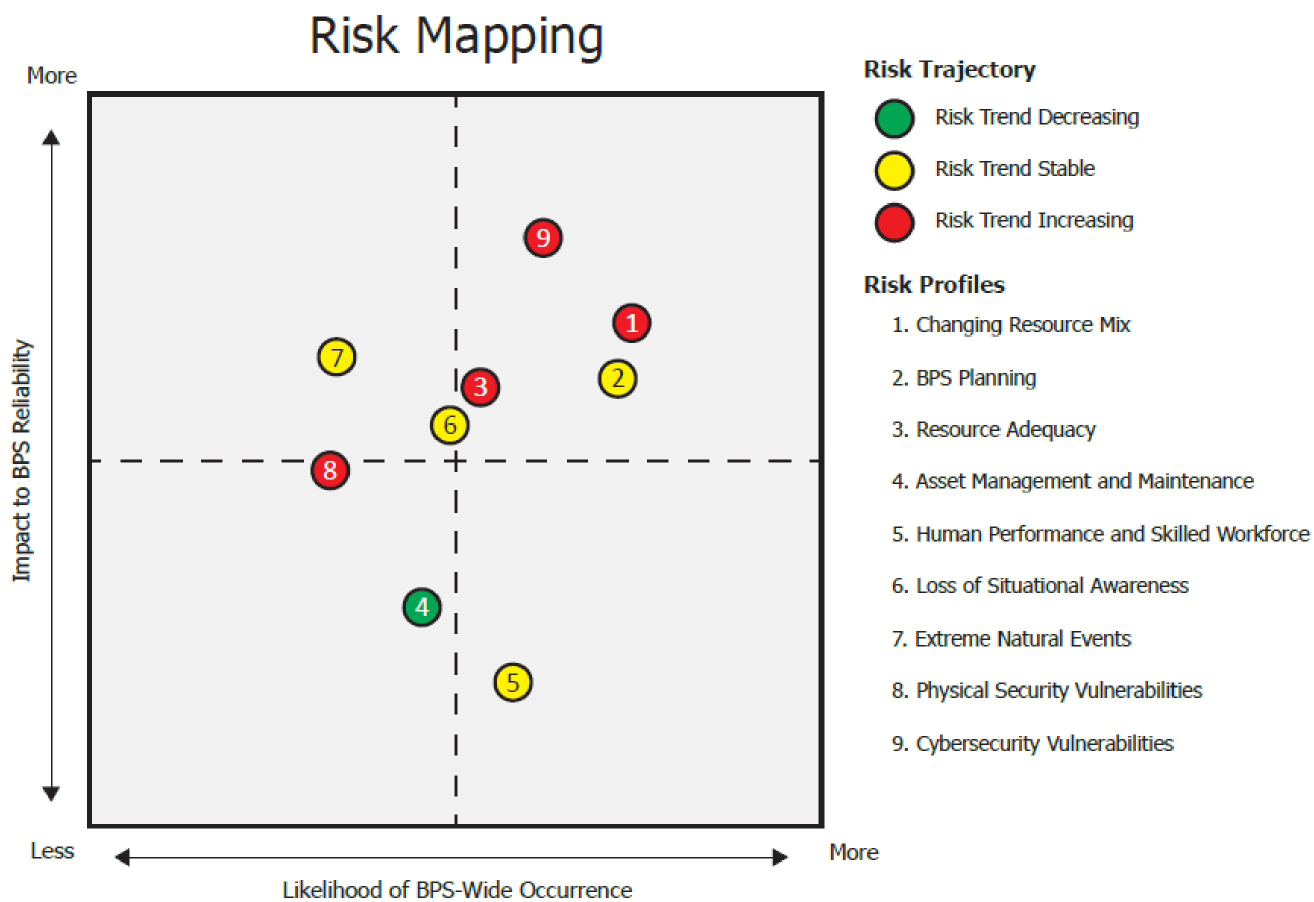


Figure 2.1: Risk Map of ERO Risk Profiles

Risk Groupings

This report provides a framework to categorize risks as High, Moderate, or Low. A Low ranking does not indicate that the risk covered in the profile is not a threat to the system; risks with Low or Moderate rankings still require industry action to reduce the likelihood of instability, uncontrolled separation, or cascading outages that adversely impact the Bulk Electric System. Regardless of the ranking or classification, all risk profiles warrant attention as the rapidly changing BPS can quickly raise the risk. High risks were based on the committee's sense of urgency or where industry focus was needed to fully understand the risks.

High Priority Risks:

- **Cybersecurity Vulnerability**: This risk profile is considered a High risk due to the increasing need for protection against a cyberattack. Cyber threats are becoming more sophisticated and increasing in number. Exploitation of cybersecurity vulnerabilities can potentially result in loss of control or damage to BPS-related voice communications, data, monitoring, protection and control systems, or tools. A cyber-attack can lead to equipment damage, degradation of reliable operations, and loss of load. Further, cybersecurity vulnerabilities can come from several sources, both internal and external, and in some instances the utility may have its cybersecurity fully tested.
- **Changing Resource Mix:** The 2015 risk profile on Regulatory Uncertainty was retired as most of the focus has transitioned to the specifics regarding the changing resource mix. The rapid rate at which fuel costs, subsidies, and federal, state, and provincial policies are affecting the resource mix are creating a new paradigm in which planners, balancing authorities, and system operators are reacting to resource additions and retirements. Further, the integration of new technologies and distributed energy resources are affecting the availability of as well as the ability of operators to see and control resources within their area.
- **Bulk-Power System Planning:** The two planning profiles from 2015 (Ineffective Planning Coordination and Ineffective Resource Planning) were combined into one profile. BPS planning is a risk closely tied to the changing resource mix because planners currently lack the ability to update or create system models and scenarios of potential future states to identify system needs based on the dynamic nature of the system. This changing system makes it increasingly difficult to evaluate BPS stability, including inertia and frequency response, voltage support (adequate dynamic and static reactive compensation), and ramping constraints.
- **Resource Adequacy and Performance:** With the acceleration of the changing resource mix, the risk profile on Generator Unavailability was revamped to include all resources and associated adequacy performance issues. Changes in the generation resource mix and new technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability in real time. Failure to take into account these changing characteristics and capabilities can lead to insufficient capacity and ERS to meet customer demands.

Moderate Priority Risks:

- **Loss of Situational Awareness**: This profile expands the profile from 2015 to encompass more than energy management system (EMS) outages. This profile also explains that the loss of situational awareness can be a precursor or contributor to a BPS event. It also highlights emerging challenges with visibility into distributed energy resource impacts on the grid. Loss of situational awareness due to insufficient communication and data regarding neighboring entities' operations is a risk as operators may act on incomplete information.
- **Extreme Natural Events:** Severe weather or other natural events (e.g., hurricanes, tornadoes, protracted extreme temperatures, geomagnetic disturbances (GMDs), floods, earthquakes, etc.) are some of the

leading causes of outages, and the industry must remain vigilant in improving preparation and coordination in order to minimize the effect of such events.

- **Physical Security Vulnerabilities**: Like cybersecurity, there is an increasing and evolving threat profile from physical attacks. Intentional damage, destruction, or disruption to facilities can potentially cause localized to extensive interconnection-wide BPS disruption for an extended period.

Low Priority Risks:

- **Asset Management and Maintenance:** The profile from 2015 on Protection Systems and Single Points of Failure was folded into the Asset Management and Maintenance and the Human Performance profile below. The failure to properly commission, operate, maintain, prudently replace, and upgrade BPS assets generally could result in more frequent and wider-spread outages, and these could be initiated or exacerbated by equipment failures. This profile highlights the need for prudent and timely equipment replacement and sound management of complex protection systems to prevent or mitigate events.
- **Human Performance and Skilled Workforce:** The continued need for skilled workers, such as protection engineers, is needed to prevent both active and latent errors both of which negatively affect reliability.

Perspectives and Conclusions

The preceding summarizes the RISC's conclusions regarding key reliability risks and areas where NERC and the industry should focus to preserve reliability in 2017 and beyond. These observations and conclusions are supported by the collective expertise within the RISC as well as the other inputs outlined in the report. Overall, these inputs provide a strong foundation for the NERC Board of Trustees for consideration as an important input to ERO Strategic Plan as well as the Business Plan and Budget.

Chapter 3: Risk Profiles

Risk Profile #1: Changing Resource Mix

Statement of the Risk

The change to the resource mix is accelerating due to fuel costs, subsidies, and federal, state, and provincial policies. Transmission planners, Balancing Authorities, and system operators of the BPS may not always have sufficient time to develop and deploy plans to mitigate reliability considerations with various resource additions and retirements.

Level of Risk

High Priority

Descriptors of the Risk

1. The rate of change (penetration rates of certain resources) and the type of change (the specific resources) are influenced by economic factors in addition to state, provincial, and federal initiatives, which sometimes impact one region, province, or state more than another. Over time, regulatory initiatives, along with lower production costs, will likely alter the nature, investment needs, dispatch of generation considering the replacement of large rotating synchronous central-station generators with natural-gas-fired generation, renewable forms of asynchronous generation, demand response, storage, smart- and micro-grids, and other technologies. Planners and operators may not have the requisite time to reliably integrate these inputs and make necessary changes.
2. The ability of regulators and industry to foresee and address reliability issues associated with these changes to the resource mix is complicated by:
    a. The lack of ancillary services, such as the ERS (e.g., voltage control and reactive support, frequency response, ramping) on the BPS, which is exacerbated by the retirement of many large rotating synchronous central station generating units.
    b. The integration of large amounts of new resource technologies, distributed energy resources, and behind-the-meter resources; the lack of low-voltage ride through; inaccurate load data to accurately forecast anticipated demand; and the inability to observe and control distributed energy resources.
    c. The need for data and information about the character of resources in the planning, operational planning, and operating time horizons so the system can be planned and operated while accounting for the contributions and implications to reliability of all resources, regardless of their location or configuration.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise and industry should continue to conduct interconnection-wide technical studies, such as frequency and inertia response, voltage support, short-circuit analysis, inter-area oscillation assessments, and electric and gas dependency studies. Also, through a stakeholder outreach and input process, inform and educate policy makers and the industry of reliability effects and interconnection requirements for the changing resource mix.
2. The ERO Enterprise should develop an effective means to gather data and insights into distributed energy resources (i.e., customer, distribution, or otherwise), and formulate plans to achieve the appropriate level of transparency and control such that implications to the BPS can be better understood.

3. Expand the collaboration, through the technical committees, with the Regional Transmission Operators (RTO)/Independent System Operators (ISOs) Council, Balancing Authorities in non-RTO/ISO market areas, other registered entities, and regulators on ERS recommendations for effective implementation as they emerge.
4. The ERO Enterprise should continue to provide independent technical assessments of the reliability impacts from the changing resource mix driven by proposed state, provincial, or federal statues and transmission provider tariffs.

Mid-term (3–5 year time frame):

5. Policy makers should engage in high-level collaboration among market operators (RTOs/ISOs), balancing authorities in non-RTO/ISO market areas, and provinces and states to establish long-term strategies for aligning policies with reliability needs.

Long-term (greater than 5-year time frame):

6. The ERO Enterprise should continue working with industry stakeholders and policy makers on reliability attributes essential to support the long-term reliability of the BPS, including equipment controls that enable system support from variable energy resources, accommodating distributed energy resources such as small end-use customer resources, distributed energy resource performance, and synchronous generation retirements.

Risk Profile #2: Bulk-Power System Planning

Statement of the Risk

BPS planning is transitioning from centrally planned and constructed resources based on forecasted load growth and reliability projects to more reactive, rather than proactive, planning based on the integration of new resources and technologies driven by policies and incentives. Due to the lack of visibility, certainty, and speed that these resources are being integrated in some areas, planners currently may lack the ability to update or create system models and scenarios of potential future states to identify system reliability needs. Planners may not have sufficient time to implement mitigation plans or reliability upgrades to address likely scenarios, driving the need for more real-time operating procedures.

Level of Risk

High Priority

Descriptors of the Risk

1. Planning and operating the BPS is becoming more complex due to:
    a. The increased and accelerated rate of plant retirements, especially conventional synchronous generation, coupled with the increasing integration of renewable, distributed, and asynchronous resources.
    b. Increased risks with the transition from a balanced resource portfolio, addressing fuel and technology risks, to one that is predominately natural gas and variable energy resources.
2. Planners need to evaluate BPS transient, mid-term, long-term, and small-signal stability, including consideration of inertia and frequency response, voltage support (adequate dynamic and static reactive compensation), and ramping constraints due to the timing and dynamic performance of the new resource mix that changes throughout the day. Planners need a complete understanding of all pertinent resources and their characteristics to identify system reliability needs and develop mitigation plans.
3. The ability to perform accurate long-term planning assessments is more difficult due to:
    a. The need for more comprehensive load models.
        i. The uncertainty and lack of visibility into load composition and resource mix along with imprecise or evolving models.
        ii. Complex load model and interaction with power electronics devices on a large scale at the distribution level that may affect BPS operations during disturbances (e.g., fault-induced delayed voltage recovery).
    b. An increasing need for transmission and system planning activities to include distributed energy resources; however, limited data availability, information sharing, enhanced models required for both system and electro-magnetic transients, and a lack of coordination can hinder the ability of planners to complete this analysis.
    c. The increased deployment of distributed energy resources within the distribution or behind-the-meter configurations will impact how the BPS responds.
    d. Uncoordinated integration of controllable device settings and power electronics installed to stabilize the system.
4. Common mode or single points of failure, such as fuel delivery systems, are emerging or have yet to be determined or evaluated.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise should coordinate and work with industry and manufacturers and developers of asynchronous resources to develop accurate dynamic models and make them available.
2. The ERO Enterprise should identify the type and frequency of information needed from distributed energy resources.
3. The ERO Enterprise should develop guidelines and best practices for developing and maintaining accurate system and electromagnetic models that include the resources, load, and controllable devices that provide ERS. This would add the benchmarking of dynamic models with Phasor Measurement Units (PMU) measurements based on actual system response to disturbance.
4. NERC should continue to collaborate with Planning Coordinators to expand development of interconnection-wide models commensurate with expected dispatches. This collaboration will support the ability to conduct more effective long-term planning assessments.

Mid-term (3–5 year time frame):

5. Continue to assess the system performance to determine if the current body of planning Reliability Standards is sufficient to address ERS.
6. NERC should collaborate with Planning Coordinators to assess the impact on reliability from well-head, storage, and fuel delivery issues and how to assess them in long-term planning studies.
7. Improve load forecasting, generator modeling, and coordination between BPS and distribution system planners and operators.

Long-term (greater than 5-year time frame):

8. Encourage vendors of power system simulation software to develop programs to enhance dynamic load modeling capabilities.

Risk Profile #3: Resource Adequacy and Performance

Statement of the Risk

The resource mix and its delivery is transforming from large, remotely-located coal and nuclear-fired power plants, towards gas-fired, renewable energy limited, and distributed energy resources. These changes in the generation resource mix and the integration of new technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability. Failure to take into account these characteristics and capabilities can lead to insufficient capacity, energy, and ERS (sometimes called "ancillary services") to meet customer demands.

Level of Risk

High Priority

Descriptors of the Risk

1. The traditional methods of assessing resource adequacy may not accurately or fully reflect the new resource mix ability to supply energy and reserves for all operating conditions.
2. Forecasting BPS resource requirements to meet customer demand is becoming more difficult due to the penetration of distributed energy resources, which can mask the customer's electric energy use and the operating characteristics of distributed resources without sufficient visibility.
3. Conventional steam resources that operate infrequently due to economics may not operate reliably when dispatched for short peak-demand periods during seasonally hot or cold temperatures.
4. Historic methods of assessing and allocating ancillary services such as regulation, ramping, frequency response, and voltage support may not ensure ERS or sufficient contingency reserves are available at all times during real-time operations.
5. Fuel constraints and environmental limitations may not be reflected in resource adequacy assessments.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise and the industry should continue to develop improved modeling and probabilistic methods to evaluate resource adequacy. This includes continued sharing of emerging trends and insights from assessments for effective resource planning and operating models. Adequacy and capacity may include augmenting the measurements of ERS, coordination of controls, balancing load with generation regardless of the location of resources, and energy adequacy in light of installed and available capacity from variable generation.
2. The ERO Enterprise should assess and develop mitigation recommendations as necessary to address single points of disruption, such as fuel contingencies, that will result in large resource outages.
3. The ERO Enterprise and the industry should continue to expand the use of probabilistic approaches to develop resource adequacy measures that reflect variability and overall reliability characteristics of the resources and composite loads, including other than seasonal peak conditions.
4. The ERO Enterprise should generate scenarios for reliability assessments that focus on the location of resource retirements and the impact on ERS.
5. Improve load forecasting, generator modeling, and coordination between BPS and distribution system planners and operators.

6. The ERO Enterprise should develop new measures of reliability beyond reserve margins, including measures on the sufficiency of ERS.
7. The ERO Enterprise and industry should continue to assess vulnerabilities from fuel availability as part of evaluating adequacy and capability to deliver resources.
8. Analyze data requirements necessary to ensure there is sufficient detail on the capability and performance of the BPS as it is impacted by distributed energy resources. The industry should gather data beyond simple demand forecasts and expand to identify resource capacity, location, and ERS capability.

Risk Profile #4: Asset Management and Maintenance

Statement of the Risk

As the system ages and operations are modified, asset management programs also change. Failure to properly commission, operate, maintain, prudently replace, and upgrade BPS assets, such as those nearing their end-of-life, could result in more frequent and wider-spread outages that are initiated or exacerbated by equipment failures or protection and control system failures.

Level of Risk

Low Priority

Descriptors of the Risk

1. A lack of visibility of common-mode failures:
   - Delayed or no industry-wide notice when new issues arise.
   - No trend information readily available.
2. Extended outage time needed to replace major equipment.
3. A lack of sufficient analytics and awareness of inadequately maintained or conditioned equipment at or above minimum standards or requirements.
4. Barriers for proactive equipment replacement programs.
5. A level of awareness and understanding of priority system upgrades.
6. Increasingly complex protection systems that must be managed and maintained to prevent or mitigate events.
7. Protection and control system misoperations exacerbate events, thereby increasing the risk for uncontrolled cascading of the BPS.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. Increase the use of NERC's Alert program to provide more detail on information requests from industry on specific assets, earlier dissemination of detailed reports, and potential follow-up activities involving maintenance and management of assets.
2. The ERO Enterprise, in coordination with industry, should improve data gathering for equipment failure modes and improve the dissemination among equipment owners, manufacturers, and associated vendors.
3. Continue to conduct webinars on equipment event lessons learned, equipment maintenance, and seasonal preparedness.
4. Continue to evaluate performance trends using additional data collected by event analysis to extract insights, issues, and trends for dissemination across industry participants.
5. Industry forums and trade groups should learn from successful asset management programs, maintenance, and lessons learned to gain insights on trends in effective asset maintenance and increase dissemination of best practices.
6. The ERO Enterprise should work with industry experts to develop industry guidelines on protection and control system management to improve performance.

7. Assess system performance to determine whether the current family of protection and control standards needs to be enhanced.

Mid-term (3–5 year time frame):

8. Coordinate with the forums, research organizations, and technical committees to establish sharing of technologies or processes that aid in condition monitoring, failure prevention, spare sharing, and recovery.
9. Coordinate with the US, Canadian, and Mexican energy agencies and industry to support power transformer reserve programs.
10. The ERO Enterprise should provide technical basis for industry to support recovery of upgrade and maintenance costs for reliability purposes.

Long-term (greater than 5-year time frame):

11. The industry should implement best practices from the sharing of technologies or processes that aid in condition monitoring, failure prevention, spare sharing, and recovery.

Risk Profile #5: Human Performance and Skilled Workforce

Statement of the Risk

The BPS is becoming more complex, and as the industry faces turnover in technical expertise, it will have difficulty staffing and maintaining necessary skilled workers. In addition, inadequate human performance (HP) makes the grid more susceptible to both active and latent errors, negatively affecting reliability. HP weaknesses may hamper an organization's ability to identify and address precursor conditions to promote effective mitigation and behavior management.

Level of Risk

Low Priority

Descriptors of the Risk

1. Organizations not implementing improvements based on past events or experiences or keeping an eye on the implementation of new technologies can hinder future operations improvements; gaps in skillsets or organizational improvement must be a priority.
2. Turnover of key skilled or experienced workers (e.g., relay technicians, operators, engineers, IT support, and substation maintenance) will lead to more protection system misoperations.
3. A lack of training programs prevents closing skillset gaps quickly.
4. Inadequate management oversight or controls leads to organizational weaknesses and inefficiencies.
5. Ineffective corrective actions lead to repeated human performance errors.
6. Legacy systems and new technology result in disparity of the skillsets needed for BPS reliability.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The HP groups at the ERO Enterprise and industry forums should expand their communication of insights throughout the industry regarding best practices for increasing HP effectiveness (publishing lessons learned/best practices and supporting the NERC HP conference and other related workshops).
2. NERC should encourage industry and key trade associations to determine the extent of expected skill gaps and develop recommendations to address the skill gaps (e.g., curricula, programs, industry support).
3. The ERO Enterprise, trade associations, and industry should promote expanding training and education programs to include HP and recruitment of the next generation of skilled workers.
4. The ERO Enterprise and the industry should promote the use of NERC cause codes to establish a common understanding of HP triggers, collect and evaluate trends in data, and develop metrics as needed.
5. Explore the development and widespread use of a near-miss database which will leverage data sources such as event analysis, near miss databases, Transmission Availability Data System (TADS), Generating Availability Data System (GADS), Demand Response Availability Data System (DADS), relay misoperations, EOP-004/OE-417 Reports, and AC equipment failures to identify patterns and risk.

Mid-term (3–5 year time frame):

6. Consider and implement high-value recommendations developed to address skills gaps identified in the short-term mitigation mentioned in the 1–2 year time frame.

Long-term (greater than 5-year time frame):

7. Industry should develop and implement a sustainable process to analyze and disseminate best practices for HP.

Risk Profile #6: Loss of Situational Awareness

Statement of the Risk

Information sharing will be vital for visibility and a complete understanding of the impacts and contributions of distributed energy resources to the BPS. Inadequate situational awareness can be a precursor or contributor to BPS events. Loss of situational awareness can also occur when control rooms are not staffed properly or operators do not have sufficient information and visibility to manage the grid in real-time. Additionally, insufficient communication and data regarding neighboring entity's operations is a risk as operators may act on incomplete information.

Level of Risk

Moderate Priority

Descriptors of the Risk

The following items can lead to inappropriate operator response or lack of action:

1. Limited real-time visibility to and beyond the immediate neighboring facilities.
2. A lack of common status information on infrastructures and resources on which operators rely (e.g., gas, dispersed resources, distributed energy resources, and data and voice communications).
3. Information overload during system events.
4. Inadequate tools or fully capable back-up tools to address reliability.
5. Lack of training on the tools and information to assess system reliability at a given point in time.
6. Incomplete data and model accuracy used to feed into real-time operations.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise should develop new measures of reliability beyond reserve margins, including sufficiency of ERS.
2. The ERO Enterprise should develop real-time notification of interconnection anomalies and outliers (e.g., large load or resource losses, large oscillations, large angle changes, low inertia).
3. The ERO Enterprise should continue to perform a root cause or common mode failure analysis of partial and full loss of key EMS capability using events analysis information and provide lessons learned and recommendations to reduce the likelihood of failure.
4. The ERO Enterprise should evaluate whether certain important applications are over reliant on a single service provider and identify mitigating actions to reduce the risk.
5. Work with the forums on an approach for ongoing identification, cataloging, and sharing of good practices related to operating tools.
6. The ERO Enterprise should develop a guideline on situational awareness for the industry to address data modeling and information sharing.
7. The ERO Enterprise should identify the type and frequency of information needed from distributed energy resources for real-time situational awareness.

Mid-term (3–5 year time frame):

8. Develop and implement a set of real-time indicators of interconnection health.
9. The ERO Enterprise should engage industry and trade organizations to develop a list of key tasks and learning objectives for wide-area monitoring as well as assessing status following system events.
10. The ERO Enterprise should engage EPRI to develop a supplement or companion to the Interconnected Power System Dynamics Tutorial that deals with wide-area monitoring under a changing resource mix based on the near-term deliverables above.

Long-term (Greater than 5-year time frame):

11. The ERO Enterprise should engage industry and trade organization and the North American Synchrophasor Initiative (NASPI) to develop a suite of supplemental and back-up tools that use synchrophasor data.
12. Establish a forum with EMS vendors to leverage the near-term and mid-term suggestions for improvement of situational awareness tools.

Risk Profile #7: Extreme Natural Events

Statement of the Risk

Severe weather or other natural events (e.g., hurricanes, tornadoes, protracted extreme temperatures, GMDs, floods, earthquakes, etc.) are one of the leading causes of outages. Severe weather can cause BPS equipment damage, fuel limitations, and disruptions of voice and data communications, which can cause loss of load for an extended period.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. Extreme natural events can damage equipment and limit fuel supplies, which may lead to localized loss of load.
2. Unmitigated GMDs could lead to widespread loss of load due to voltage instability in certain regions.
3. Widespread damage to certain types of BPS infrastructure can extend outages due to unavailability of nearby replacement equipment or specialized capabilities.
4. Physical damage to generation fuel sources, such as natural gas pipelines or storage facilities, can degrade reliable operations of the BPS.
5. Damage to voice and data communications, as well as water supplies, can make certain critical facilities vulnerable and reduce the ability to serve load.
6. The industry does not have full knowledge or coordination in accessing the existing spare equipment inventory.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. Complete the GMD Reliability Standards and start geomagnetic induced currents (GIC) data gathering and analysis.
2. E-ISAC and industry should expand communications among ISACs, including the Telecommunications, Water, and Natural Gas ISACs.
3. Study multiple simultaneous limitations on natural gas deliveries during extreme weather.
4. Participate in exercises that incorporate extreme physical events and implement recommendations from exercise or drills such as GridEx.
5. Incorporate E-ISAC and Electricity Subsector Coordinating Council (ESCC) communications protocols into industry disaster preparedness processes.
6. The industry, trades, and forums should evaluate inventories of critical spare transmission equipment and increase as required.
7. The Department of Energy, the industry, trades, and forums should identify appropriate mitigations to prevent spare equipment gaps and improve transportation logistics.
8. The ERO Enterprise and the industry should leverage best practices and the sharing of lessons learned to expand coordination during extreme weather events among Reliability Coordinators, Balancing Authorities, and Transmission Operators.

9. NERC and industry should plan a workshop that is coordinated with U.S. federal agencies, Canadian, and Mexican governmental authorities to address high-impact low-frequency event response, recovery, and communications vulnerabilities.

Mid-term (3–5 year time frame):

10. Identify and promote specific resiliency best practices to plan for extreme events.
11. The ERO Enterprise should conduct more detailed special assessments that integrate:
    a. Natural gas availability, pipeline capacity, and storage facility impacts on reliability under severe scenarios.
    b. Other interdependencies, such as long-haul communications and water supply.
    c. Analytic data trend insights regarding resiliency under severe weather conditions, identifying preventable aspects for BPS reliability.
12. The ERO Enterprise should apply the severity risk index (SRI), on a more granular regional level to measure system resilience and restoration performance for loss of generation, transmission, and load. These efforts should consider or develop new comparative and descriptive metrics.
13. The ERO Enterprise should perform trend analysis on historical impacts on the BPS of extreme natural events.

Long-term (greater than 5-year time frame):

14. Analyze data from GMD events to further the understanding of GIC effects on Bulk Electric System facilities to support enhancements to models and standards.
15. Institutionalize relationships among ESCC, government, and industry partners to enhance the culture of recognizing and addressing extreme physical event preparedness across industry.
16. Develop a plan to review and improve the trend of SRI as indicative measure of system resilience and restoration performance for loss of generation, transmission, and load.
17. To facilitate preparedness, consider preparing sensitivity analyses to simulate the impacts from the most extreme natural events experienced to date in a planning area.

Risk Profile #8: Physical Security Vulnerabilities

Statement of the Risk

Intentional damage, destruction, or disruption to facilities can cause localized to extensive interconnection-wide BPS disruption potentially for an extended period.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. The increasing and evolving threat around physical attacks.
2. The exposed nature of the grid, which is vulnerable and difficult to protect.
3. Long lead times associated with manufacturing and replacing some equipment, which can increase complexity of restoration after physical attacks that damage BPS equipment.
4. The level of industry knowledge or coordination in accessing the existing spare equipment inventory.
5. Physical damage to generation fuel sources, such as natural gas pipelines, which will degrade the reliable operations of the BPS.
6. Damage to long-haul telecommunications and water supplies, which will make certain critical facilities vulnerable and reduce the ability to serve load.
7. An EMP event, which could lead to widespread loss of load in certain regions.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise should continue to oversee the implementation of NERC's Physical Security Reliability Standard entitled Critical Infrastructure Protection (CIP-014-2).
2. E-ISAC and industry should expand communications among ISACs, including the Telecommunications, Water, and Natural Gas ISACs.
3. The ERO Enterprise should develop effective metrics formulated to understand the trend of physical attacks and potential threats.
4. Assess the risks of physical attack scenarios on midstream or interstate natural gas pipelines, particularly where natural gas availability will impact generation and the reliability of the BPS in NERC's long-term reliability assessments and planning activities.
5. Promote existing and new efforts to improve a spare equipment strategy and prioritization.
6. Develop a catalog of regional/national exercises that incorporate extreme physical events and share with industry, thus supporting increased participation across industry. Whenever possible, expand exercises to include more facilities and industries.
7. The forums and trades should perform the following activities:
   a) Identify and promote specific resiliency and vulnerability assessment best practices with planning for extreme events, including good physical security assessment practices.
   b) Develop an event guideline outlining prevention strategies and event response and recovery protocols for sabotage scenarios.

8. In collaboration with the Critical Infrastructure Protection Committee and industry stakeholders, develop a risk process to address the potential impacts of physical security threats and vulnerabilities.

Mid-term (3–5 year time frame):

9. The industry should review and update restoration plans while accounting for physical security scenarios.
10. Develop performance and metrics reporting on joint E-ISAC and Telecommunications ISAC assessments of potential physical attack disruptions while differentiating from vandalism or theft incidents.
11. Conduct a special regional assessment that addresses natural gas availability and pipeline impacts under physical attack scenarios.
12. The Department of Energy, the industry, trades, and forums should identify appropriate mitigations to spare equipment gaps and transportation logistics.
13. The ERO Enterprise, the industry, trades, and forums should evaluate inventories of critical spare transmission equipment as necessary based on a spare equipment strategy and prioritization.
14. The industry should evaluate mechanisms for cost recovery of implementing specific resiliency strategies by the industry.
15. Industry should work with the technical committees and forums to develop mitigation strategies and physical security assessment best practices.
16. Expand participation in security exercises other than GridEx in order to reflect extreme physical events.
17. Facilitate planning considerations to reduce the number/exposure of critical facilities.

Long-term (greater than 5-year time frame):

18. Institutionalize relationships among ESCC, government, and industry partners to enhance the culture of recognizing and addressing extreme physical event preparedness across industry.
19. Foster the development of methods, models, and tools to simulate system reliability impacts for the planning and operational planning time horizons.

Risk Profile #9: Cybersecurity Vulnerabilities

Statement of the Risk

Exploitation of cybersecurity vulnerabilities can potentially result in loss of control or damage to BPS-related voice communications, data, monitoring, protection and control systems, or tools. Successful exploitation can damage equipment, causing loss of situational awareness and, in extreme cases, can result in degradation of reliable operations to the BPS, including loss of load.

Level of Risk

High Priority

Descriptors of the Risk

1. Cybersecurity threats result from both external and internal vulnerabilities:
    a. Exploitation of employee and insider access.
    b. Weak security practices of host utilities, third-party vendors, and other organizations.
    c. Growing sophistication of bad actors, nation states, and collaboration between these groups.
2. Interdependencies from the Department of Homeland Security Critical Infrastructure Sectors[4] (Communications, Financial Services, Oil and Natural Gas Subsector, and Water) with their own cyber vulnerabilities can impact BPS reliability.
3. Legacy architecture coupled with the increased connectivity of the grid expands the attack surface of BPS protection and control systems:
    a. Increased automation of the BPS through control systems implementation.
    b. Business needs accelerating the convergence of information technology (IT)/operational technology (OT).
    c. IT/OT infrastructure management, out-of-date operating systems, and the lack of patching capability/discipline.
4. Ineffective teamwork and collaboration among the federal, provincial, state, local government, private sector and critical infrastructure owners can exacerbate cyber events.
5. A lack of staff that is knowledgeable and experienced in cybersecurity, control systems, and the IT/OT networks supporting them (historically separate organizations and skillsets), symptomatic across all industries, hinders an organization’s ability to detect and prevent cyber incidents.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. Address FERC critical infrastructure protection (CIP) directives in *Revised Critical Infrastructure Protection Reliability Standards*, 154 FERC ¶ 61,037 (2016).
2. Address FERC directives in *Revised Critical Infrastructure Protection Reliability Standards*, 156 FERC ¶ 61,050 (2016) on supply chain risk management.
3. In collaboration with the Critical Infrastructure Protection Committee (CIPC) and industry stakeholders, develop a risk process to address the potential impacts of cyber security threats and vulnerabilities.

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[4] https://www.dhs.gov/critical-infrastructure-sectors

4. NERC should continue information sharing protocols among interdependent ISACs.
5. The E-ISAC should continue outreach to industry to increase registration and utilization of E-ISAC portal.
6. The E-ISAC should mature the cybersecurity risk information sharing program (CRISP) and encourage expanded participation.
7. NERC and the CIPC should prioritize lessons learned from regional and national exercises (*e.g.*, GridEx) and publish lessons learned and guidelines as needed.
8. Facilitate planning considerations to reduce the number/exposure of critical facilities.
9. The industry should encourage the development of a peer review process for emerging risks.
10. The industry should create and foster an internal culture of cyber awareness and safety.
11. NERC should develop effective metrics formulated to understand the trend of cyber-attacks and potential threats.

Mid-term (3–5 year time frame):

12. The ERO Enterprise should develop a feedback mechanism from CIP standards implementation to evaluate the standard and lessons learned from technology deployment.
13. The ESCC should operationalize the cyber mutual assistance framework to address issues with recovery after a cyber-attack.
    a. Cross-industry sharing of best practice incident response plans.
    b. Creation and/or expansion of security operations centers that incorporate the BPS (IT/OT convergence areas).
14. Assist industry efforts to address supply chain vulnerability.
15. The ERO Enterprise with industry should develop agreed-upon levels of cyber-resilience suitable for BPS planning and operations.

Long-term (greater than 5-year time frame):

16. The ERO Enterprise and industry should develop methods, models, and tools to simulate cyber impacts on system reliability, enabling BPS planning to withstand an agreed-upon level of cyber resiliency.
17. The ERO Enterprise and industry should develop industry operating guidelines that incorporate an agreed-upon level of cyber resilience.
18. The ERO Enterprise should create and document pathways that enable the integration of new technologies while maintaining or enhancing the agreed-upon level of cyber resilience.