UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Indianapolis Power & Light Company	)	
Complainant,	)	
v.	)	**Docket No. EL17-___-000**
Midcontinent Independent System Operator, Inc.	)	
Respondent.	)	

COMPLAINT OF INDIANAPOLIS POWER & LIGHT COMPANY

Fast Track Processing Requested

TABLE OF CONTENTS

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COMPLAINT OF INDIANAPOLIS POWER & LIGHT COMPANY AND REQUEST FOR FAST TRACK PROCESSING

Pursuant to Sections 206, 306, and 309 of the Federal Power Act ("FPA")[1] and Rule 206 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Rules of Practice and Procedure,[2] Indianapolis Power & Light Company ("IPL") respectfully submits this Complaint against the Midcontinent Independent System Operator, Inc. ("MISO"). Pursuant to Rule 206(h), IPL respectfully requests Fast Track processing through expedited Commission action.[3]

Specifically, in terms of expedited action, IPL's state-of-the-art grid-scale battery installation, the IPL Advancion® Energy Storage Array, a.k.a. the Harding Street Station Battery

[1] 16 U.S.C. §§ 824e, 825e, and 825h (2015).

[2] 18 C.F.R. § 385.206 (2016).

[3] 18 C.F.R. § 206(h) (specifying Complainants may seek expedited relief through Commission action on the pleadings).

Energy Storage System ("HSS BESS"),[4] achieved commercial operation on May 20, 2016. Because there are no appropriate MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff")[5] provisions, business practice rules, or means for MISO to dispatch this device without harm to the battery, IPL has administratively placed the device "behind-the-meter." While the HSS BESS is currently providing Frequency Control Services ("FCS"), automatic grid-scale service, including Primary Frequency Response ("PFR"),[6] and contributes to MISO's compliance with North American Electric Reliability Corporation ("NERC") Reliability Standard BAL-003-1.1,[7] there is no provision in the MISO Tariff to compensate IPL for the essential reliability service that the HSS BESS delivers today. The Commission should find that the MISO Tariff is unjust and unreasonable, unduly discriminatory and provides an undue preference to other Resources, for several related reasons discussed below. IPL notes that once the Commission makes such a finding, IPL has met its burden under FPA Section 206. Nevertheless, this Complaint also provides recommended remedies to address

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[4] Battery Energy Storage Systems, or "BESS," are also sometimes referred to as Battery Energy Storage Arrays, or "BESAs."

[5] Capitalized terms not otherwise defined herein have the meanings ascribed thereto in Section 1 of the MISO Tariff. For ease of reference, this document is referred to herein as the "Tariff" or the "MISO Tariff." The MISO Tariff is currently located under MISO's "FERC Electric Tariff" eTariff title, and can be found here: http://etariff.ferc.gov/TariffBrowser.aspx?tid=1162

[6] As defined by the Commission, PFR is "a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over." *Third-Party Provision of Primary Frequency Response Service*, 153 FERC ¶ 61,220 at PP 14 and P 47 (2015). The Commission commonly refers to PFR in several rulemakings and other issuances. FCS is meant to refer to the full spectrum of response, as described by NERC, and PFR is a category within the FCS spectrum. While the automatic response can occur throughout the Frequency Control continuum, IPL will use the term PFR, which is also known in some contexts as "Primary Frequency Control," to denote the automatic response of the HSS BESS to deviations in the MISO system frequency level.

[7] The standard can be found at: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=BAL-003-1.1&title=Frequency%20Response%20and%20Frequency%20Bias%20Setting&jurisdiction=United%20States The standard was approved by the Commission in Order No. 794. *Frequency Response and Frequency Bias Setting Reliability Standard*, 146 FERC ¶ 61,024 (2014) ("Order No. 794"). BAL-003-1 was later amended to include non-substantive revisions via errata filing and redesignated as BAL-003-1.1. *See N. Am. Elec. Reliability Corp*., Docket No. RD15-6-000, Delegated Letter Order (Nov. 13, 2015).

the unjust and unreasonable and unduly discriminatory or preferential aspects of the MISO Tariff.

I. ACTIONS REQUESTED

A. Reform of the MISO Tariff

As discussed in greater detail below, IPL asks the Commission to take three actions. The first action should be completed in the near-term. The second and third actions should be taken quickly, but it may be reasonable to permit further stakeholder input before MISO must make implementation filings. Indeed, IPL respectfully submits that Commission supervision may be warranted in this case. Given the fact that MISO has been involved for some time in an ongoing, indeterminate stakeholder process on battery energy storage issues, the Commission should place tight time limits on any required MISO compliance filings. As explained in greater detail herein, the Commission should:

- Find the MISO Tariff to be unjust, unreasonable, and unduly discriminatory and preferential for failing to compensate suppliers of PFR. MISO should pay for the provision of PFR (automatic reaction to positive and negative frequency deviations on the MISO system from the standard) under a separate schedule at the real-time locational marginal price ("LMP") adjusted for performance with a benefits factor or mileage rate.
- Find the MISO Tariff to be unjust, unreasonable, and unduly discriminatory and preferential with respect to the current dispatch protocols and compensation methodologies for Regulating Service (Secondary Frequency Control) as applied to Lithium ion battery technology and all fast resources.
  - MISO should be ordered to reform the current dispatch protocol to accommodate the HSS BESS and all fast resources. If applied to Lithium ion batteries, the SER dispatch protocol (developed for flywheels only) would degrade the useful life,

interfere with the requisite state of charge ("SOC") management, and diminish the benefits the battery provides to the grid.

- Batteries should be ***paid*** and not ***charged*** the LMP when withdrawing ***in response to a frequency deviation***. They should only pay the LMP for Auxiliary load and state of charge management.
- MISO should be directed to adopt a mileage rate for Regulating Services that addresses greater grid benefits of fast resources in a manner similar to the Regulation D payment factor used by PJM.[8]

- Find the MISO Tariff to be unjust, unreasonable, and unduly discriminatory and preferential with respect to the limitations on resources providing other products – Ancillary Services, Energy, Ramp, and Capacity that they are technically capable of providing. While the generic term "stored energy resource" or SER, encompasses many technologies including batteries, the MISO Tariff SER resource type was designed solely for the operating characteristics of flywheels and limits them to providing Regulating Service.[9] Accordingly, the restrictions on the products to be provided by all resource types in the MISO Tariff should be lifted. The Commission should direct that the Tariff be reformed so that Resources technically capable of providing various products under the Tariff be permitted to provide such products, regardless of resource label or technology. Additionally, a new resource type for Lithium ion batteries should be added to the Tariff that respects the operating characteristics of this technology and permits the

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8 *See, e.g.*, PJM Operating Agreement at Section 1.11.4.

9 As stated by MISO, "the SER category itself is not limited to flywheel storage despite the fact that it was developed to accommodate that type of storage technology." *See Electric Storage Participation in Regions With Organized Wholesale Electric* Markets, Docket No. AD16-20-000, Response of the Midcontinent Independent System Operator, Inc. at 9 (May 16, 2016).

grid to benefit from its unique capabilities. While MISO may argue that batteries could simply be registered under another resource type (for example Generation, Demand Response Type-1, Demand Response Type-II, Behind-the-Meter Generation, or Use-Limited Resource), MISO has admitted, "when MISO originally developed the non-SER resource categories, MISO did not specifically consider whether such categories could accommodate the unique features of various storage technologies."[10] Resources capable of providing various products under the MISO Tariff, so long as they can qualify, should be permitted to provide such products.

B. Fast Track Processing

The Commission should act expeditiously to bring MISO's current practices up to date so that customers, including IPL ratepayers, can receive the benefits of leading technological innovations within the industry – in this case, batteries that can deliver essential reliability and other Ancillary Services more efficiently than traditional generators. As the need for PFR grows, Lithium ion batteries could provide critical help in addressing the need. More importantly, "Lithium ion batteries can be designed to provide many Ancillary Services as well as those services not categorized as Ancillary Services such as Ramp."[11] Further, they could be designed to replace peakers, and could be called upon in the event of an under-frequency load shed or cascading outage event.[12]

IPL emphasizes that customer harm is not theoretical in this case. IPL's HSS BESS is extant – it is built, is interconnected, and is providing PFR continuously, supporting the grid with no means for compensation for the services rendered.

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[10] *Id.* at 3.

[11] Franks Testimony at page 32, lines 5-6.

[12] *Id.* at lines 7-14.

Accordingly, IPL requests Fast Track processing. Prompt Commission action regarding compensation for PFR is particularly important for all of the reasons discussed below. For the relief requested concerning Regulating Service and the other identified action items, IPL requests that the Commission place tight time limits on MISO compliance and consider a Commission-supervised process.

II. COMMUNICATIONS

Pursuant to Rule 2010,[13] IPL hereby designates the following individuals for service of documents in this proceeding:

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III. DESCRIPTION OF THE PARTIES

A. Indianapolis Power & Light Company

IPL is a MISO Transmission Owner and a public utility that owns and operates generating facilities with a capacity of approximately 3,400 MW and the transmission and distribution facilities required to provide retail electric service to more than 475,000 customers in and around Indianapolis, Indiana. IPL participates in the energy and ancillary service markets overseen by MISO, both as a supplier and a load-serving-entity ("LSE"). IPL is the owner of the HSS BESS.

[13] 18 C.F.R. § 385.2010.

IPL is a corporation organized under the laws of the State of Indiana with its principal place of business in Indianapolis, Indiana. IPL is a subsidiary of Ipalco Enterprises, Inc. ("IPALCO"). IPALCO is a subsidiary of AES Corporation ("AES").

B. AES Corporation

AES is a Delaware corporation with its principal place of business in Arlington, Virginia. AES has issued shares of stock and debt securities to the public. CDP Infrastructure Fund GP, a wholly-owned subsidiary of La Caisse de depot et placement du Quebec (the "CDPQ"), also owns a minority equity interest in IPALCO. The CDPQ, which manages private and public pension funds in the Province of Quebec, was founded in 1965 by an act of the National Assembly of Canada and is organized under the laws of Quebec. The CDPQ is not a publicly-traded corporation.

AES is a diversified, Fortune 200 global energy company. AES provides affordable, sustainable energy in seventeen countries through a diverse portfolio of distribution businesses as well as thermal and renewable generation facilities. AES indirectly owns approximately 5,400 MW of electric generating capacity throughout the United States that is sold under market-based rates through competitive generation companies and qualifying facilities under the Public Utility Regulatory Policies Act of 1978. In addition to its competitive generation subsidiaries and affiliates, AES indirectly owns approximately 6,400 MW of generation through its traditional, vertically-integrated utility subsidiaries, IPL and The Dayton Power and Light Company ("DP&L").

AES is a pioneer in the commercialization of battery-based energy storage on the grid, placing the first Lithium ion grid battery into service in 2008. Since then, AES has invested in several generations of storage projects and hundreds of millions of dollars in development and commercial installations. AES Energy Storage is the world leader in energy storage, with 136 MW of installed capacity in five countries and seven locations. The company is also under contract to provide another 228 MW over the next year and a half.

C. MISO

MISO is a Commission-approved regional transmission organization ("RTO") that administers the MISO Tariff. MISO is the Transmission Provider and market administrator for IPL and for the MISO region. The MISO Tariff contains provisions relevant to the operation of IPL's HSS BESS.

IV. BACKGROUND

A. The HSS BESS

The HSS BESS is grid-scale Lithium ion battery-based energy storage system located at the Harding Street Generation Station, on the southwest side of Indianapolis. The battery contains a 20 MW array of Lithium ion cells, and is designed to provide what is commonly-termed, a "flexible 40 MW" of nearly instantaneous PFR for the benefit of IPL's customers and the MISO grid.[14] It responds to deviations in MISO system frequency by injecting energy when system frequency falls below NERC standards or withdrawing energy when system frequency is too high, thus providing significant flexible PFR capacity.[15]

In addition, the HSS BESS could become a Load Modifying Resource satisfying 5 MW of Planning Reserve Margin Requirement under Module E of the MISO Tariff. To qualify as a Load Modifying Resource, the battery must provide on 12-hour notice continuous energy for a

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[14] Construction on the Harding Street BESS began on July 8, 2015. The battery achieved commercial operation on May 20, 2016. The HSS BESS was registered as an SER to be effective June 1, 2016. However, as the HSS BESS cannot participate in the current market without harm to the battery, IPL submitted paperwork to remove it from the model on June 8, 2016. While the model is only updated quarterly, MISO took steps to assure no inadvertent charges or credits would accrue to the device.

[15] The HSS BESS is the first grid-scale energy storage array in the fifteen-state MISO footprint.

four-hour period.[16] The battery can continuously provide PFR, then, if called upon, deliver energy continuously over the four hours of the peak, and then return to supply PFR.[17]

B. MISO's Existing Tariff and Practices Related to Energy Storage

On September 14, 2007, as amended on September 19, 2007, MISO filed a revised proposal to implement a day-ahead and real-time Ancillary Services market.[18] On February 25, 2008, the Commission conditionally accepted the proposal.[19] The Commission's order, issued nine years ago, recognized the importance of removing barriers to innovative technologies:

> While we understand the need to tailor requirements to maximize participation by generation resources, we also want to ensure that all resources receive comparable treatment. For this reason, we require the Midwest ISO to evaluate, through stakeholder discussions, adjustments to operating requirements and ASM procedures that will remove barriers to comparable treatment of DRRs and new technologies in the regulating reserve markets and to provide a report on its efforts to incorporate these resources into its markets within 60 days of the date of this order. We also require the Midwest ISO to submit revised tariff sheets, if adjustments are proposed, in a compliance filing to be submitted concurrently with the 60-day informational filing.[20]

On April 25, 2008, MISO submitted a compliance filing, which proposed provisions on the use of SERs.[21] On December 18, 2008, the Commission issued an order, which among other things, conditionally accepted the April 25, 2008 filing's proposed provisions.[22] However, the

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16 MISO Tariff at § 69A.3.6.

17 Franks Testimony at page 32, lines 7-9.

18 *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER07-1372-000, Tariff Filing of Midwest Independent Transmission System Operator, Inc. (Sept. 14, 2007); *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER07-1372-000, Tariff Filing of Midwest Independent Transmission System Operator, Inc. (Sept. 19, 2007).

19 *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172 (2008).

20 *Id*. at. P 365.

21 *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER07-1372-007, Compliance Filing of Midwest Independent Transmission System Operator, Inc. (Apr. 25, 2008).

22 *Midwest Indep. Transmission Sys. Operator, Inc*., 125 FERC ¶ 61,319 at P 26-27, 31, 34, 42-45 (2008). With regard to SERs, the Commission ordered MISO to make the following changes and clarifications:

- Limit self-scheduling of SERs to the regulating reserve requirement, and to prohibit SERs from being Capacity Resources or satisfying zonal operating reserve requirements;

Commission directed certain additional 30-day compliance measures and an informational report.[23]

On January 22, 2009, MISO proposed additional revisions so as to: (1) limit the self-scheduling of SERs to the Regulating Reserve requirement; (2) clarify that SERs will not qualify as Capacity Resources under Module E of the Tariff; and (3) clarify that SERs cannot be used to satisfy zonal Operating Reserve requirements.[24]

Further, on May 12, 2009 in Docket No. ER09-1126-000, MISO filed proposed modifications that characterized SERs as short-term storage devices where SERs would be limited to offering Regulating Reserves, and not Energy or Contingency Reserves, in the MISO markets.[25] Unlike other Resource types, the Energy dispatch on a Stored Resource was not to be included in the co-optimization algorithm.

In comments, IPL noted the January 22 Filing created potential barriers to entry for new SER technologies:

> IPL is concerned that the current approach with regard to SERs and similar technologies may limit their optimal and economical use in the market. Instead, IPL advocates a resource-specific qualification process for new technologies such as batteries and other types of Stored Energy Resources ("SERs"). It is necessary for the business rules to be flexible enough to accommodate the unique characteristics and benefits of each technology rather than force all to fit within

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- Change the protocols for setting the market clearing price, to clarify that SERs that cannot provide reserves continuously over a sixty-minute period may not set the market clearing price for reserves in the day-ahead market, but that SERs that can provide reserves in five-minute intervals are not precluded from setting the market clearing price in the real-time market; and
- Revise the market monitoring and mitigation procedures set out in Module D of the Transmission and Energy Markets Tariff ("TEMT") to clarify that such procedures apply to SERs.

[23] *Id.* at P 27, 31, 34, 45 (requiring: (1) a compliance filing within 30 days of the order to make certain Tariff revisions; and (2) an informational report on any Stored Resource-related reliability issues within 180 days from the Stored Resources implementation date).

[24] *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER07-1372-016 et al, Tariff Filing of Midwest Independent Transmission System Operator, Inc. (Jan. 22, 2009).

[25] *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER09-1126-000, Tariff Filing of Midwest Independent Transmission System Operator, Inc. (May 12, 2009).

> either the limitations of the SER business rules or the rules for traditional generation types.[26]

By focusing the compliance filing language on a particular technology, flywheels, with very specific operating parameters, MISO's Tariff language failed to look ahead to the deployment of storage technologies with vastly different operating characteristics. As noted by IPL in 2009:

> IPL's primary concern with the Midwest ISO Compliance Filing with regard to SERs, is that it may inadvertently pigeonhole technologies, and prevent their unique features from being leveraged in the ASM. In order to participate as a seller in the ASM, a resource must be registered as one of the following: Generation Resource; SER; or Demand Resource – Type II. IPL is concerned that, as currently drafted, the ASM may not be broad enough to encompass batteries and other known kinds of resources that may be able to provide services in the market.
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> * * *
>
> IPL's particular concern is with the ability of batteries to participate in the ASM. Batteries provide a good example of how the ASM's current construct may be too exclusionary. Broadly speaking, batteries are devices that can store energy in the form of chemical energy and then convert chemical energy into electrical energy. In order for batteries to participate in the ASM, they must register as either a Generation Resource, Demand Resource type II or a SER. Some battery types may easily meet all of the criteria necessary to register as a Generation Resource (thus allowing them the greatest flexibility necessary to participate in the ASM), while others may meet most, but not all of the criteria – and thus may only qualify as SERs. Although batteries unable to qualify as Generation Resources may be <u>physically</u> able to provide energy for the morning ramp on demand, and thus provide benefits to the system, their qualification only as SERs limits their opportunities to participate in the ASM. Thus, batteries may not offer ramp service (energy) economically in the day-ahead market, even if they are physically capable of providing it.[27]

IPL also noted concerns with MISO's proposed settlement of SERs that would discourage deployment:

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[26] *Midwest. Indep. Transmission Sys. Operator, Inc*., Docket No. ER07-1372-014, Comments on Compliance Filing of Indianapolis Power & Light Company at 2 (Feb. 12, 2009).

[27] *Id*. at 4-5 (emphasis in original).

> [U]nder the current resource categories, batteries may provide Regulation service; however, the settlement business rules prevent battery-type resources from being paid for such service. When Generation Resources are deployed to provide Regulation service, they are given a target set point, for example 30 MWs. … Payment is integrated within the hour and determined to be at the base point or midpoint from 0-30, or 15MW.
>
> In contrast to Generation Resources, batteries charge and discharge onto the grid. So for a battery in this example, the range integrated would be 30 to -30; or a midpoint of 0…. Since the quantity for which a unit is paid the market clearing price is this midpoint, then payment in this over simplified example is 0 X the market clearing price, or $0.00. The business settlement rules must be amended to rectify this problem and encourage greater participation by batteries and similar resources in the Midwest ISO market.[28]

IPL advocated a stakeholder process that would recognize that batteries such as BESS were different from flywheels:

> IPL encourages the Midwest ISO to seek additional stakeholder input and develop a regime that would permit registration of a wider range of resources as they are implementing the SERs-related features of the ASM.[29]

The stakeholder process that IPL asked for in 2009 was not commenced by MISO until January, 2016. As explained in the testimony of Lin Franks, it has not resulted in any of the necessary changes to the MISO Tariff, operating practices, or compensation methodologies for PFR and Regulating Service.[30]

In an order issued on December 31, 2009, the Commission accepted the MISO's compliance filing, and conditionally accepted the MISO's proposed Tariff revisions in Docket No. ER09-1126-000, to be effective January 1, 2010, as requested, subject to further compliance.[31] The Commission, however, clearly recognized the limitations in the MISO proposals with respect to energy storage, which at that time focused on flywheel units, and that

[28] *Id*. at 5-6.

[29] *Id*. at 4.

[30] Franks Testimony at page 16, lines13-23; page 17, lines 1-9.

[31] *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,303 (2009).

there would be a need to revisit the issue of storage participation in the broader array of MISO markets in the future:

> As an initial matter, we note that the Midwest ISO proposal is intended to implement a specific technology, the fly-wheel technology developed by Beacon Power, so that it can provide a specific reserve product, regulating reserves. While we appreciate the need to integrate this new technology into the operations of the Midwest ISO in a timely manner, as the Midwest ISO proposes, we do not want to foreclose the consideration of other storage technologies and the use of those technologies for other reserve products, such as contingency and spinning reserves. It is for this reason that we are requiring the Midwest ISO to evaluate other storage technologies for all reserve products, as discussed further below.
>
> We conditionally accept the Midwest ISO's proposed revisions to its Tariff regarding Stored Resources. We expect that the proposed tariff revisions will allow the fly-wheel technology to participate in the Midwest ISO regulating reserve market as Stored Resources on a comparable basis to other resources that provide regulating reserves.[32]

Indeed, the Commission expressly stated,

> we share Xcel's and IPL's concern that the specificity of these provisions may be insufficient to address barriers to the participation of other new technologies and storage devices, including those providing longer term storage, in the Midwest ISO's markets. We understand that the Midwest ISO has had stakeholder discussions to consider concerns regarding long-term storage. In the Ancillary Services Market Order, the Commission directed the Midwest ISO to "evaluate, through stakeholder discussions, adjustments to operating requirements and A[ncillary] S[ervices] M[arket] procedures that will remove barriers to comparable treatment of . . . new technologies in the regulating reserve markets." Accordingly, we direct the Midwest ISO to submit an informational report to the Commission within 60 days of the date of this order on its efforts to incorporate long-term storage resources into its markets and its evaluation of barriers to the integration of these technologies into its markets. Consistent with the Ancillary Services Market Order, we also require the Midwest ISO to submit revised tariff sheets, if adjustments are

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[32] *Id.* at PP 40-41.

> proposed, in a compliance filing to be submitted concurrently with the 60-day informational filing.[33]

In its March 1, 2010 informational report, MISO noted that it accommodated long-term storage in its markets in the form of pumped storage resources.[34] With respect to battery energy storage systems, MISO stated:

> the Midwest ISO is currently investigating both internally and through discussions with its stakeholders the potential need for Tariff modifications that might enhance the ability of alternative long-term storage resources to participate in its markets. Specifically, at the February 2, 2010 meeting of the Markets Subcommittee ("MSC"), the Midwest ISO discussed with stakeholders its on-going investigation into potential Tariff modifications that could increase the opportunity for other long-term storage devices, to participate in the Midwest ISO's markets. This has been added to ongoing-issues lists with both the MSC and Midwest ISO's internal Market Advisory Committee. The Midwest ISO will continue to update the MSC regarding its progress and any proposed recommendations.[35]

As evidenced by the need for this Complaint, no progress on accommodating energy storage capabilities on a resource-neutral way has been implemented in MISO. No grid-scale storage prior to the HSS BESS has been connected to the MISO system. By contrast, PJM has approximately 200 MW of storage devices primarily due to the creation of a regulation product and performance criteria for fast-moving resources.

C. IPL and AES Energy Storage Engagement With MISO and MISO Stakeholders

As noted above, IPL, for approximately two and a half years, has been advocating that MISO implement the necessary Tariff and system changes that can accommodate the HSS BESS and other non-flywheel storage systems. While MISO and the Commission attempted to pave a road for flywheels, there is no path for storage systems like HSS BESS. Moreover, there are no

[33] *Id*. at P 64.

[34] *Midwest Indep. Transmission Sys. Operator, Inc*., Docket Nos. ER07-1372-014 and ER09-1126-000, Informational Report of the Midwest Independent Transmission System Operator, Inc. at 4 (Mar. 1, 2010).

[35] *Id*. at 4-5.

flywheel systems that are providing grid-scale Regulating Service in MISO, the only product they are eligible to sell. The HSS BESS is now in service, but without a workable approach to be paid for all of the services rendered and others that it can provide. This result is not consistent with the statutory requirements that all rates subject to the Commission's jurisdiction must be just and reasonable and not subject any person to any undue prejudice or disadvantage.[36]

IPL has attempted to work extensively with MISO and the MISO Stakeholders over the past two and a half years. Despite these efforts, issues associated with the deployment of the HSS BESS have not been resolved. Accordingly, IPL is compelled to seek the requested relief from the Commission.

V. ARGUMENT

FPA Section 206(a) states that whenever the Commission "upon complaint" finds that "any rate, charge, or classification," employed by any public utility, or that "any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force . . ."[37] The just and reasonable standard under Section 206 is the same as it is under Section 205.[38] While Section 206 requires a complainant to carry the burden of showing that an existing rate may no longer be just and reasonable, the complainant need only show the lack of justness and reasonableness (or undue discrimination or preference) for the existing rate, but does not

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36 16 U.S.C. §§ 824d(a) and 824d(b).

37 16 U.S.C. § 824e(a).

38 16 U.S.C. § 824d; *FirstEnergy Serv. Co. v. FERC*, 758 F.3d 346, 353 (2014) (finding the just and reasonable lodestar is no loftier under Section 206 than under Section 205).

bear a "dual burden" in also having to demonstrate the justness and reasonableness of a replacement rate.[39]

Further, just because a tariff was found to be just and reasonable at one time does not preclude the Commission from later finding it to be unjust and unreasonable.[40] In particular, technological changes, or other changed circumstances, may cause a provision to be no longer just and reasonable, not unduly discriminatory or unduly preferential.[41]

In this case, as discussed below, the MISO Tariff is no longer just and reasonable, and not unduly discriminatory or preferential for several reasons. In the interest of organization regarding issues that overlap to some extent, IPL submits that it is useful to break down the areas to be addressed into three parts.

- First, MISO Schedule 3, Regulating Reserve, is no longer just and reasonable because PFR is not unbundled and separately compensated from MISO's "Regulation Reserve" ancillary service (*see* Section V.A below).
- Second, MISO Schedule 3 and other provisions concerning Regulation service are unduly discriminatory and preferential because, as a practical matter, only generators, Demand Response Resource ("DRR") Type II, and flywheels can receive compensation as a

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[39] *Id*.

[40] *See e.g., Maryland PSC v. PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,169 at P 31 (2008), *citing Ameren Services Co. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 121 FERC ¶ 61,205 at P 33 (2007) (finding "a tariff provision implementing a particular rate or practice that was found reasonable at one time does not preclude the Commission from later reviewing the provision to determine whether it continues to be just and reasonable."); *California Indep. Sys. Operator Corp.*, 125 FERC ¶ 61,055 at P 97 (2008) (finding that the Exceptional Dispatch mechanism accepted by the Commission in a September 2006 Order may no longer be just and reasonable , and expressing concern CAISO's intended expanded reliance on Exceptional Dispatch, and payment structure "may yield unjust and unreasonable outcomes that unduly discriminate against non-resource adequacy resources."); *California Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,150 (order on Section 206 investigation, accepting new Exceptional Dispatch proposal by CAISO), *on reh'g*, 129 FERC ¶ 61,144 (2009*); Indep. Energy Producers Ass'n v. California Indep. Sys. Operator Corp*., 116 FERC ¶ 61,069 at P 38 (2006) (finding compensation to generators under the must offer obligation no longer just and reasonable).

[41] *See e.g., Reactive Power Requirements for Non-Synchronous Generation*, 153 FERC ¶ 61,175 at P 14 (2015) (requiring wind generators to provide dynamic reactive power based on technological advancements).

Resource under Schedule 3. Indeed, the Tariff rules regarding Resources that can provide Regulation and the accompanying dispatch protocol would cause damage and shorten the life of grid-scale Lithium ion batteries. Further, it is inappropriate to assess charges to batteries when they are responding to a frequency that is too high, and the current mileage factor of one (1) no longer correctly implements Order No. 755[42] in that it does not provide greater compensation to faster-performing assets, and is no longer just and reasonable based on current circumstances (*see* Section V.B below).

- Third, the MISO Tariff restrictions on the products to be offered by "SERs" is no longer just and reasonable, as it was designed for flywheel technology and unduly discriminates against other types of storage technologies, including grid-scale batteries utilizing Lithium ion batteries.[43] The Tariff definition also provides an undue preference for flywheel technology (*see* Section V.C below). The Commission should order MISO to amend its Tariff to permit batteries to provide any service – Energy, Capacity, Ramp, or Ancillary Service they are capable of providing. In fact, no resource type should be denied the opportunity to provide any service it can technically provide. The potential harm in this case is real— the HSS BESS is already in service.

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[42] *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) ("Order No. 755"); *reh'g denied*, 138 FERC ¶ 61,123 (2012) ("Order No. 755-A").

[43] As MISO has stated:

> when MISO originally developed the non-SER resource categories, MISO did not specifically consider whether such categories could accommodate the unique features of various storage technologies. Second, as previously mentioned, the SER category was developed specifically for short-term storage, and its limitation to Regulating Service may not be appropriate for other forms of battery storage technology that have the capability to provide more than just Regulating Service. Consequently, MISO's operational system, software and procedures for these resource categories may not yet suitably address any unique operating characteristics of certain non-short-term storage resources.

See Electric Storage Participation in Regions With Organized Wholesale Electric Markets, Docket No. AD16-20-000, Response of the Midcontinent Independent System Operator, Inc. at 3 (May 16, 2016).

In sum, the Commission should act in order to allow the HSS BESS, a cutting-edge extant resource with a Commission-approved interconnection agreement in place,[44] to provide fast-response essential reliability services automatically or dispatched appropriately, and be compensated for the provision of such services.

A. The MISO Tariff Is Unjust and Unreasonable and Unduly Discriminatory With Respect to PFR.

The MISO Tariff is unjust and unreasonable, unduly discriminatory and preferential because it has not unbundled Schedule 3, "Regulating Reserve," and does not provide for compensation specifically for PFR. The MISO Tariff uses the basic structure developed in Order No. 888,[45] which contains ancillary services in schedules, such as Schedule 3, Regulation and Frequency Response, or as MISO now terms it, "Regulating Reserve." Nevertheless, as discussed below, the rationale for housing all of these distinct essential reliability grid services under the general heading of "Regulating Reserve" and not compensating providers for each distinct service can no longer be deemed to be just and reasonable, not unduly discriminatory or preferential.

As discussed below, there are several reasons for this change in circumstances necessitating a change to MISO's Tariff. These reasons include:

- The basic rationale stemming from Order No. 888 is no longer valid. It is no longer the case that the "same equipment" provides all of the services under the

[44] *See Midcontinent Independent Sys. Operator, Inc*., 155 FERC ¶ 61,211 (2016); *see also Midcontinent Indep. Sys. Operator, Inc*., Docket No. ER16-1211-003, Delegated Letter Order (Sept. 28, 2016).

[45] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. Regs. ¶ 31,036 (1996), *order on reh'g,* Order No. 888-A, FERC Stats. Regs. ¶ 31,048 (1997), *order on reh'g,* Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

heading of Schedule 3, Regulation and Frequency Response.[46] The HSS BESS is designed to provide faster response services, such as PFR, and while capable of providing Regulation (and Energy), it would not be economically viable or operationally prudent to operate a grid-scale Lithium ion battery in a manner that only provides Regulation under MISO's Tariff.

- As a practical matter, only generators (or flywheels) can receive compensation under MISO Schedule 3. The MISO markets are co-optimized. That is, Energy and most Ancillary Services (including Schedule 3 services) are procured through a single security-constrained commitment and dispatch process. While SERs, by definition, are only eligible to receive payment for Regulation, the SER category was designed and defined only for flywheel technology. As a practical matter, Lithium ion batteries cannot provide Regulating Reserve within MISO because dispatch and settlement for the operating characteristics of flywheels is harmful to batteries and would force them to operate at an unjust and unreasonable rate.
- The Commission should act now to remove the barriers to using state-of-the-art technologies to arrest the decline in PFR. Reform of the MISO Tariff to allow specifically for unbundled PFR will help reverse the decline of the availability of such services, hastened by the change in MISO's generation fleet from heavy coal reliance to a renewable and gas-heavy portfolio.

1. Importance of Automatic Frequency Control

Before turning to each of the aforementioned points in more detail, set forth below, IPL provides a brief explanation of the continuum of FCS. Essential reliability services include those

[46] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,707 (1996).

needed to control frequency and voltage to support grid stability. Resources providing these requirements should be compensated for their performance.[47] PFR is a distinct and critical requirement for interconnected grid operations.[48] Indeed, NERC has stated "Frequency Response is the most important of the required responses and frequency responsive reserve is the most important of the reserves."[49] In Order No. 819, the Commission amended its market-based rate regulations to define the PFR product as "a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over."[50] Granting market-based rates, however, is irrelevant in MISO as MISO does not pay sellers for the service.[51]

The MISO Tariff is unjust and unreasonable and unduly discriminatory and preferential because it does not recognize and pay for PFR as a separate Ancillary Service. Indeed, as the

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[47] PFR is the only ancillary service needed to support the operation of the interstate transmission system that is not unbundled; it is the only ancillary service that MISO does not compensate for pursuant to rates on file at the Commission. *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc*., 109 FERC ¶ 61,005 at P 33 (2004), *order on rehearing*, *Midwest Indep. Transmission Sys. Operator, Inc*., 110 FERC ¶ 61,267 (2005) ("We recognize, as does Midwest ISO, that generators that provide reactive power to support the transmission system should be compensated for providing that service.").

[48] Regulation service is different than PFR because regulation resources respond to automatic generation control signals, which respond to Area Control Error. Regulation is centrally coordinated by the Balancing Authority. PFR, in contrast, is autonomous and is not centrally coordinated.

[49] NERC Reliability Guideline: Operating Reserve Management - at 10-11,

> The first step in recovery is to arrest the frequency change caused by the imbalance. In most circumstances, this arresting action is performed automatically by the frequency response of generators and load on the Interconnection within the first few seconds of the imbalance. If there is insufficient response or frequency response reserve (FRR), the Interconnection frequency will reach underfrequency relay trip points before any of the other steps can be initiated. Therefore, frequency response is the most important of the required responses and frequency responsive reserve is the most important of the reserves.

http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Operating%20Reserve%20Management%20Guideline%20-%2020130718.pdf.

[50] *Third-Party Provision of Primary Frequency Response Service*, 153 FERC ¶ 61,220 at PP 14 and 47 (2015) ("Order No. 819").

[51] While MISO considered the provision of PFR as "inherent in a unit's function" *See Third-Party Provision of Primary Frequency Response Service*, Docket No. RM15-2-000, Comments of Midcontinent Independent System Operator, Inc. at 2 (Apr. 27, 2015), MISO has no requirements that resources provide PFR. *See* Franks Testimony, page 22, lines 21-23; page 23, lines 1-2.

attached Franks testimony discusses, the full FCS continuum can really be broken up into four services: PFR (also known in some contexts as "Primary Frequency Control"), Secondary Frequency Control, Tertiary Frequency Control, and Time Control. The following NERC table, also available in Exhibit No. IPL-2 from the Franks Testimony, summarizes these distinctions.

Frequency Control Time Continuum Table

Control	**Ancillary Service**	**Dispatched / Automatic**	**Purpose**	**How is it accomplished?**	**NERC STANDARD**
Primary Frequency Control	Primary Frequency Control or Primary Frequency Response	Automatic	To arrest in 10-60 seconds the degradation of frequency following an event such as a generator tripping or a weather related transmission outage.	All generators with active governors installed automatically or other resources capable of automatically responding react to deviations in system frequency by increasing or decreasing their output.	FRS-CPS1 BAL003-1
Secondary Frequency Control	Regulation, Spinning Reserves	Dispatched	To manage the difference between scheduled generation and load with actual. This is called Area Control Error (ACE is for a balancing area and includes a frequency deviation and frequency bias components).	Resources are dispatched by the Balancing Authority/RTO adjusting their output in an attempt to balance real time generation, load, and scheduled interchange. Response required in up to 10 minutes in most RTOs	CPS1-CPS2-DCS-BAAL
Tertiary Frequency Control		Manual and Dispatched	To correct the imbalance created by the event.	Reliability Coordinator can redispatch on line generating resources, mandate load shed / curtailment and / or dispatch resources not already online. This process can take 10 minutes to hours depending upon the event.	BAAL-DCS
Time Control	Time Error Correction	Automatic	To regulate system frequency in a manner that keeps synchronous clocks running accurately.	RTOs set system frequency levels in order to elicit a response from generator governors or other resources capable of automatically responding.	TEC

Reliable operation of a power system depends on maintaining frequency within predetermined boundaries above and below a scheduled value, which is 60 Hertz (Hz) in the continental United States.[52] The Commission has recognized that Interconnections experience system contingencies (such as loss of a large generator or load) that disrupt the balance between generation and load, and result in frequency deviations that can cause under-frequency load shedding, additional generation tripping, and cascading outages.[53] PFR is a measure of an Interconnection's ability to arrest and stabilize frequency deviations within pre-determined limits following the sudden loss of generation or load, and is affected by the collective responses of generation and load resources throughout an entire Interconnection.[54]

NERC describes "Primary Frequency Response" as "actions to arrest and stabilize frequency in response to frequency deviations. [PFR] comes from generator governor response, load response (motors), or other devices that provide immediate response based on local (device-level) control."[55] NERC states that PFR is the "cornerstone for system stability" because PFR prevents under-frequency load shedding events, prevents damage to equipment, and that the droop response part of PFR is critical to system restoration efforts.[56] PFR is an *immediate and automatic* response, and cannot be provided efficiently through dispatch. In this regard it is distinct from Regulation. As categorized by NERC:

- Primary Frequency Control (Frequency Response) – Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations. It is

52 *Frequency Response and Frequency Bias Setting Reliability Standard,* 146 FERC ¶ 61,024 at P 6 (2014) ("Order No. 794").

53 *Essential Reliability Servs. & the Evolving Bulk-Power Systems-Primary Frequency Response,* Notice of Inquiry, 154 FERC ¶ 61,117 at P 3 (2016) ("PFR NOI").

54 *Id*. at P 4.

55 NERC, Primary Frequency Response Initiative, Presentation at 5 (April 7, 2015). Available here: http://www.nerc.com/pa/rrm/Webinars%20DL/Generator_Governor_Frequency_Response_Webinar_April_2015.pdf

56 *Id*. at 3.

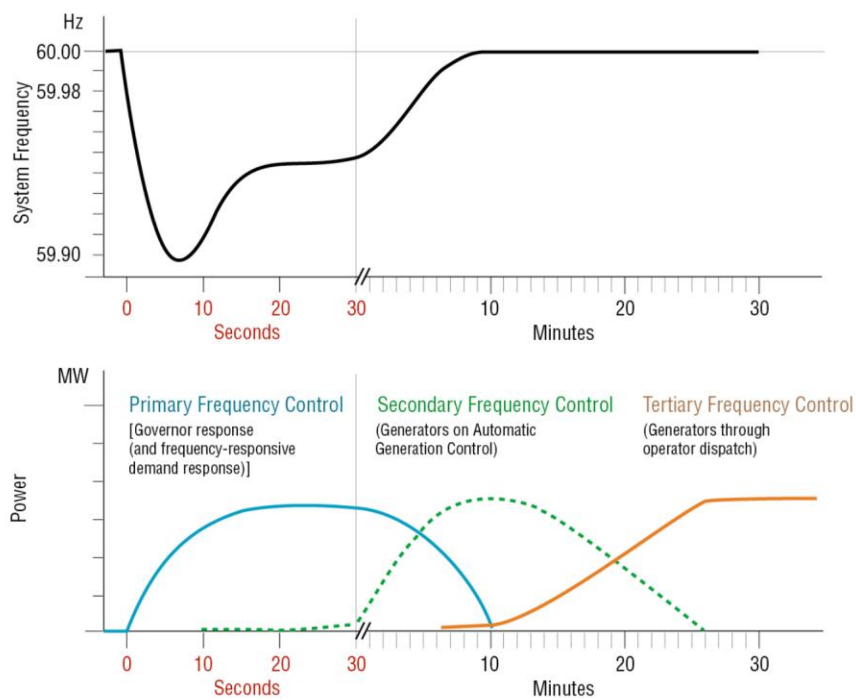
the immediate and automatic reaction or response of power from a system or power from elements of the system to a change in locally sensed system frequency.

- Secondary Frequency Control (Regulation) – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

- Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error ("ACE"). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.[57]

Figure 1 illustrates the temporal distinctions between PFR, Regulation, and subsequent measures to stabilize system operations.

Figure 1



[57] *See* NERC Frequency Response Standard Document Dated at 2-3 (November, 2012). Available here: http://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/Bal-003-1-Background_Document-Clean-2013_FILING.pdf

The Commission has recognized similar distinctions:

> Primary frequency response involves the autonomous, automatic, and rapid action of a generator, or other resource, to change its output (within seconds) to rapidly dampen large changes in frequency. Regulation, also known as secondary frequency response, is produced from either manual or automated dispatch from a centralized control system, generally using the communications and control system known as automatic generation control (AGC). In both cases, capacity must be set aside to provide the responses.[58]

While a Regulating Service market exists in MISO, it is not a tool for PFR. It is a means to assist MISO in management of ACE which is a measure of the instantaneous difference between a Balancing Authority's net actual and scheduled interchange,[59] taking into account the effects of Frequency Bias and correction for meter error. The standard that prescribes the required performance of Balancing Authorities is BAL-001-2, Real Power Balancing Control Performance. While the standards' stated purpose is to control Interconnection frequency within defined limits, this standard requires the Balancing Authority to operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit ("BAAL") for more than 30 consecutive clock-minutes. Performance to the standard is measured averaged over an hour.[60] It is not focused on immediate response to a frequency deviation.

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[58] *Third-Party Provision of Primary Frequency Response Service*, 150 FERC ¶ 61,092 at P 12 (2015).

[59] Interchange is the energy transfers that cross Balancing Authority boundaries.

[60] Franks Testimony at page 22, line 13.

2. MISO Schedule 3, Regulating Reserve, Should Be Unbundled, or the Commission Should Take Some Other Action to Provide for Compensation for PFR.

a. The Rationale Under Order No. 888 for Not Breaking Out PFR Is No Longer Valid.

The rationale for not having PFR broken out as separate services is no longer valid. It is well-settled that even though a tariff, rule, regulation, or practice is approved by the Commission at one time does not mean that later in time it cannot be found to be unjust and unreasonable or unduly discriminatory.[61] In particular, technological change can necessitate a change in Commission findings regarding continued justness and reasonableness.[62]

In Order No. 888, the Commission made the decision to package together "Regulation and Frequency Response" as *pro forma* tariff Schedule 3. The Commission recognized that Regulation and Frequency Response were two separate services, but combined them in Schedule 3 of the *pro forma* tariff because ***at that time*** they would be provided by the same generator equipment. The Commission stated:

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[61] *See, e.g., Md. PSC v. PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,169 at P 31 (2008), citing *Ameren Services Co. v. Midwest Indep. Transmission Sys. Operator, Inc*., 121 FERC ¶ 61,205 at P 33 (2007) ("a tariff provision implementing a particular rate or practice that was found reasonable at one time does not preclude the Commission from later reviewing the provision to determine whether it continues to be just and reasonable."); *Cal. Indep. Sys. Operator Corp.*, 125 FERC ¶ 61,055 at P 96 (2008) (finding that the Exceptional Dispatch mechanism accepted by the Commission in a September 2006 Order may no longer be just and reasonable, and expressing concern CAISO's intended expanded reliance on Exceptional Dispatch, and payment structure "may yield unjust and unreasonable outcomes that unduly discriminate against non-resource adequacy resources."), *Cal. Indep. Sys. Operator Corp*., 126 FERC ¶ 61,150 (order on Section 206 investigation, accepting new Exceptional Dispatch proposal by CAISO), *on reh'g* 129 FERC ¶ 61,144 (2009); *Indep. Energy Producers Ass'n v. Cal. Indep. Sys. Operator Corp.,* 116 FERC 61,069 at P 38 (2006) (following a complaint by the Independent Energy Producers Association, the Commission found that the compensation to generators under the must-offer obligation in the CAISO tariff was no longer just and reasonable).

[62] *See, e.g., Reactive Power Requirements for Non-Synchronous Generation*, 153 FERC ¶ 61,175 at P 14 (2015) ("In Order No. 661, the Commission declined to require dynamic reactive power capability from wind generators, unless the System Impact Study showed that dynamic reactive power capability was needed for system reliability, reasoning that dynamic reactive power capability may not be needed in every case. Based on technological advancements, the Commission no longer believes it is just and reasonable and not unduly discriminatory or preferential to exempt wind generators from the requirement to provide dynamic reactive power."); *see also* Final Rule, 155 FERC ¶ 61,277 at P 38 (2016) (adopting requirement that all new wind generators have dynamic reactive power capability).

> NERC proposes that Frequency Response Service be identified as a related but distinct service. NERC indicates that all control areas are expected to have generation and control equipment to respond automatically to frequency deviations in their networks. …
>
> We conclude that Regulation Service and Frequency Response Service are the same services that make up the Load Following Service referenced in the NOPR. *While the services provided by Regulation Service and Frequency Response Service are different, they are complementary services that are made available using the same equipment*. For this reason, we believe that Frequency Response Service and Regulation Service should not be offered separately, but should be offered as part of one service.[63]

Thus, in 1996, the Commission made the decision to *not* separately break out what it called at the time, "Frequency Response Service" because at that time, Frequency Response Service and Regulation were provided using the same equipment. Today, after the introduction of batteries that can also provide PFR, the Commission's statement that only generators provided the service is no longer correct and the undue preference afforded generators in this regard is no longer justified. Indeed, the HSS BESS is *designed* to provide PFR, which is a service that is *not* dispatched. In fact, the HSS BESS and generators with governors respond automatically to frequency deviations across the frequency control continuum. These devices respond to frequency deviations regardless of cause. While the HSS BESS *can* provide Regulating Reserve as designed by MISO, or Energy, provision of such service under the current MISO protocols does not optimize the battery, and indeed, risks damaging the Lithium ion cells.[64] Thus, the same equipment may not, in fact, provide all of the services that the Commission chose to bundle under Order No. 888. For example, Regulation may be provided by traditional generation, while PFR may be provided by a Lithium ion battery, such as the HSS BESS. Thus, as a factual

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[63] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,707 (1996) (emphasis added).

[64] Franks Testimony at page 27, lines 16-23; page 28; page 29, lines 1-4. The issue of shortening the life of the cells is also discussed, *infra*, in Section V. B. herein, regarding reforms needed pertaining to the provision of Regulation.

matter, technological change has spurred a shift in facts that undermines the Commission's original underlying rationale in Order No. 888. In light of changed circumstances, IPL respectfully submits that the time has come to revisit the determination in Order No. 888 as applicable to MISO Schedule 3.

b. Unbundling Is Consistent With Commission Actions to Improve Market Opportunities and Compensation Methodologies for Fast-Responding Resources

Unbundling PFR and compensating resources that provide for these reliability requirements under a separate schedule and based on the efficiency in which the service is provided would be consistent with other recent Commission Orders and proceedings.

(1) Order No. 755

In Order No. 755, the Commission required RTOs to compensate "frequency regulation" resources based on the actual amount of frequency regulation service provided in responding to a transmission system operator's automatic generator control ("AGC") signal for purposes of responding to actual or anticipated frequency deviations or interchange power imbalances. Specifically, Order No. 755 directed RTOs to implement a two-part payment for frequency regulation service, including: (1) a capacity payment that includes the marginal unit's opportunity costs; and (2) a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.

Order No. 755 recognized that faster-ramping, or stated another way, resources capable of faster responses to signals, should be compensated more than slower-responding resources, with respect to the provision of what it termed, "frequency regulation."[65] Further, the

[65] Order No. 755 at P 2.

Commission found that certain practices of some RTOs result in "economically inefficient economic dispatch of frequency regulation resources."[66] To be clear, the Commission drew a clear distinction between the subject of Order No. 755, that is, "Frequency Regulation," which involves a response to a dispatch signal, and "frequency response" or "primary frequency control," which is provided through an automated response.[67] Order No. 755 did *not* apply to the latter category of resources, those resources providing PFR.

Nevertheless, Order No. 755 was an important step by the Commission in that it recognized the different types of service embedded within the Schedule 3 "Regulation and Frequency Response" umbrella. Most significantly, it recognized that faster-responding resources were more valuable and should be compensated to a greater degree for this type of service as compared to traditional resources. IPL proposes that the Commission adopt a similar approach to compensation for PFR. Resources, including various types of grid-scale batteries, can be customized to supply different types of services across the spectrum.

In this case, the HSS BESS can respond in one second and is at least 96 percent efficient as compared to far less efficient generators, as discussed in the Franks testimony.[68] Thus, consistent with Order No. 755, the HSS BESS can provide targeted PFR service and do so far more efficiently than traditional generators.

(2) Order No. 819

In Order No. 819, the Commission took the critically important step of clearly distinguishing between Regulation service and PFR. Indeed, Order No. 819 provided a clear definition of PFR: "primary frequency response service is defined as a resource standing by to

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66 *Id*.

67 *Id*. at n. 5.

68 Franks Testimony at page 11, lines 6-18.

provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over."[69] To be sure, Order No. 819 focused on clarifying that providers of PFR could provide the service at market-based rates. But, for the purposes of this proceeding, the critical takeaway is that the Order clearly recognized the distinction between PFR and other types of services which had, up until that point, been lumped together under the general Schedule 3 heading.

While Order No. 819 acknowledges BAL-003-1 (now BAL-003-1.1),[70] and the Commission's adoption of the BAL 003-1 requirement applying at the Balancing Authority level, Order No. 819 did not *require* that Balancing Authorities (*i.e*., in this case, MISO) to compensate providers of PFR. Rather, the order stated that it was permissible for sellers to provide the service at market-based rates, and left unaddressed the full range of options regarding non-market-based options.[71] However, the ability to sell at market-based rates is rendered moot by MISO's failure to offer any compensation for PFR, though MISO suggested the possibility of using a schedule, dubbed "Schedule 3a," to provide for separate compensation.[72]

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69 Order No. 819 at P 14.

70 As described herein, BAL-003-1was later amended to include non-substantive revisions via errata filing and redesignated as BAL-003-1.1. *See N. Am. Elec. Reliability Corp*., Docket No. RD15-6-000, Delegated Letter Order (Nov. 13, 2015).

71 Order No. 819 at P 69. MISO's Comments stated, "[a]s an example, when provision of frequency response is vital within a BA, all generators could be required to provide governor response via protocols and interconnection agreements. On the other hand, if a BA only needed a limited amount of frequency response, a service schedule (such as a "Schedule 3a") could be designed to pay those generators that demonstrated consistent provision of frequency response. Under this Schedule 3a, the users of frequency response would pay for the service and those generators that did not provide frequency response could pay under such a proposal as well. In summary, because frequency response needs vary based on BA characteristics, each BA should have the flexibility to address those needs in the manner that most effectively meets its individual circumstances." *Third-Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services*, Docket No. AD14-7-000, Comments of Midcontinent Independent System Operator, Inc. at 6 (Jun. 9, 2014).

72 *Id*.

(3) Primary Frequency Response Notice of Inquiry

On February 18, 2016, the Commission issued a Notice of Inquiry ("NOI") entitled, "Essential Reliability Services and the Evolving Bulk Power System – Primary Frequency Response."[73] This NOI examines several issues, including the issue of whether or not providers of PFR should be compensated.

Specifically, the Commission raises the issue of reexamining Schedule 3 compensation, when it asks:

> Are there benefits to separating Frequency Response Service under Schedule 3 and creating a separate ancillary service covering each individually? If so, how should a new *pro forma* Primary Frequency Response Ancillary Service be structured?[74]

Given the experience with the HSS BESS to date, IPL answers emphatically "yes." The Commission should unbundle MISO Schedule 3. As explained earlier and in the Testimony of Lin Franks, the HSS BESS automatically provides PFR, more efficiently than traditional generators.[75] At the same time, while other resources derive revenues from Energy, Regulation or other services, the HSS BESS cannot under the current MISO Tariff. Therefore, the Order No. 888 rationale for bundling Schedule 3 under the Regulation heading no longer works for the most efficient resources available. Indeed, it unduly discriminates against the most efficient resources and provides an undue preference to less efficient resources.

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73 *Essential Reliability Services and the Evolving Bulk Power System – Primary Frequency Response*, 154 FERC ¶ 61,117 (2016) ("PFR NOI").

74 *Id*. at P 54 (question 6).

75 Franks Testimony at page 11, lines 6-10.

c. A Separate Charge for PFR Sends Appropriate Price Signals

A separate charge for PFR sends the appropriate price signal and is consistent with, and furthers the Commission's goals of price formation. Keeping the true cost of PFR muted within the current Schedule 3 rubric is, in fact, inconsistent with recent Commission initiatives on price formation.

In June 2014, the Commission initiated a proceeding in Docket No. AD14-14-000, to evaluate issues regarding price formation in the energy and ancillary services markets operated by RTOs/ISOs.[76] As set forth in the notice, LMP and market-clearing prices used in energy and ancillary services markets ideally "would reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service."[77] Eventually, the Commission issued Order No. 825,[78] in which the Commission stated:

- Some current RTO/ISO settlement practices fail to reflect the value of providing a given service, thereby distorting price signals and failing to provide appropriate signals for resources to respond to the actual operating needs of the market.[79]

- As set forth in the NOPR, we reiterate the goals of price formation are to: (1) maximize market surplus for consumer and suppliers; (2) provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; (3) provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and, (4) ensure that all suppliers have an opportunity to recover their costs.[80]

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[76] *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, Notice of Initiation of Proceeding (Jun. 19, 2014).

[77] *Id*. at 2.

[78] *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 155 FERC ¶ 61,276 (2016) ("Order No. 825").

[79] *Id*. at P 2.

[80] *Id*. at P 5.

- Second, the proposed reforms will also help provide transparency and certainty so that market participants understand how compensation and prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system.[81]

- As discussed below, providing the correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, maintain reliability, and increase transparency is fundamental to proper formation of energy prices, helping to ensure just and reasonable rates, terms and conditions of service.[82]

The Commission should, consistent with Order No. 825, provide greater transparency so that market participants "understand how compensation and prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system."[83] Further, unbundling PFR will also provide the correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, maintain reliability, and increase transparency.[84] The HSS BESS is providing PFR, responding automatically in one second to deviations from the set frequency. Yet, there is no compensation under the MISO Tariff.[85] Generators that provide PFR may include the costs of providing the service through market offers for other products. The HSS BESS does not have the same options for cost recovery as its useful life would be significantly degraded by the current MISO dispatch protocol that prevents appropriate SOC management and would degrade the life of the cells.[86]

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81 *Id*. at P 7.

82 *Id*. at P 54.

83 *Id*. at P 7.

84 *Id*. at P 54.

85 As the Seventh Circuit held, utilities and FERC should not approve rates for transmission or electric services that do not "reflect to some degree the costs actually caused by" the person or entity paying them. *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (quoting *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

86 Franks Testimony at page 27, lines 16-23; page 28; page 29, lines 1-4.

d. The Commission Should Act to Arrest the Decline of Frequency Response.

PFR is declining in the Eastern Interconnection in part due to an increase in the deployment of renewable resources and in part due to the retirement of generators that can provide PFR albeit in a slower and less efficient fashion than the HSS BESS can.[87] In MISO there is no requirement to provide PFR (even though as a Balancing Authority MISO will be required by NERC to provide a defined level of PFR by the end of this year).[88]

The time has come to separately provide for PFR and Regulating Service under the MISO Tariff. The Commission should act immediately by directing that a new schedule be added to the MISO Tariff to allow for resources that provide PFR to be compensated appropriately. This change can be put in place immediately and pave an appropriate and equitable path that will allow just and reasonable treatment for the provision of an essential reliability service without being unduly discriminatory or preferential to any technology. It will also provide the impetus for additional state-of-the-art batteries to be installed in the footprint to support the grid as more renewable resources are interconnected and more traditional generators are retired. This proposed path addresses the market distortions that result from other resources not being appropriately compensated (in fact, being paid nothing at all) for the PFR service they provide.

Despite the recognition of PFR as an essential reliability service, there has been a decline in the amount available. In 2010, NERC began surveys and studies in an effort to understand the steady decline in PFR, particularly in the Eastern Interconnection. As documented in the

[87] Franks Testimony at page 12, lines 12-18.

[88] *See Frequency Response and Frequency Bias Setting Reliability Standard*, 146 FERC ¶ 61,024 (2014).

DOE/National Energy Technology Report "Frequency Instability Problems in North American Interconnections" published May 1, 2011 ("DOE/NETL Report"):[89]

> Over the past decade, the North American Electric Reliability Corporation (NERC) has observed an increase in frequency stability problems. For example, frequency response in the Eastern Interconnection has deteriorated significantly over this period, so that progressively smaller power disturbances are able to induce significant frequency deviations.[90]
>
> Several causes of this decline have been proposed, including changes in:
>
> 1. An interconnection's moment of inertia: Power systems with multiple smaller turbine generators on-line (*i.e.*, a primarily distributed generation system) have less rotational inertia than systems with fewer but larger turbine generators (*i.e.*, a more centralized generation system), giving the more distributed system less kinetic energy immediately available to mitigate frequency changes. Furthermore, as more non-rotating (photovoltaic, fuel cell) and slowly rotating (wind) generators come on line, the kinetic energy per unit of generating capacity available to the overall power system to stabilize frequency decreases.
>
> 2. Load types: Some end-use devices, such as electric motors, contribute to frequency stability because they use more power at higher frequencies and less power at lower frequencies, thereby helping demand adjust to meet supply. As the load in North America changes, with less industrial consumption and more commercial and residential consumption, it includes more electronics and variable-speed drives that do not demonstrate the same beneficial frequency-power relationship as inductive motors.
>
> 3. Generation control practices: Deregulation and competition in the generation industry have provided operators with incentives to operate plants at peak local efficiency (versus what is optimal for the overall power system) resulting in changes in generation control practices. Unfortunately, some operating practices can result in a lowering of the available range of governor control of on-line generators. This reduces the available level of primary frequency control, the ability of the system to react within a few seconds to stabilize system frequency.
>
> 4. Types of reserves and their availability: Deregulation and competition also have provided control area operators with incentives to keep generation reserves at a minimum. To reduce costs, some operators have organized into reserve sharing

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[89] This report was prepared by Energy Sector Planning and Analysis ("ESPA") for the United States Department of Energy ("DOE"), National Energy Technology Laboratory ("NETL"). This work was completed under DOE NETL. The report can be found here: https://www.netl.doe.gov/energy-analyses/temp/FY11_FrequencyInstabilityProblemsinNorthAmericanInterconnections_060111.pdf

[90] DOE/NETL Report at 5.

groups (RSGs) that collectively meet their reserve requirements resulting in. lower levels of reserves available to respond to frequency disturbances.

5. Frequency control (monitoring and regulating) practices: Controlling frequency requires primary frequency control using Governors and Energy Storage Devices; secondary frequency control primarily consisting of automatic generation control (AGC) centrally dispatched as through a market to reduce area control error (ACE) to within acceptable limits; and tertiary controls bring available generators on-line over a period of minutes to hours to re-stabilize the frequency at the nominal level. The need for devices to efficiently provide the Essential Reliability Services of frequency and voltage control is critical with the increase of renewable and gas fired generation resources replacing coal resources if reliability is to be maintained.[91]

The Commission has recognized and expressed an appropriate concern over the decline in PFR capabilities:

> The combined impacts of lower system inertia and lower frequency responsive capability online may adversely affect reliability during disturbances because lower system inertia results in more rapid frequency deviations during disturbances. This, in turn, may result in lower frequency nadirs, particularly if the primary frequency capability online is not sufficiently fast. This is a potential reliability concern because, as the frequency nadir lowers, it approaches the Interconnection's UFLS trip setting, which could result in the loss of load and additional generation across the Interconnection.
>
> These developments and their potential impacts could challenge system operators in maintaining reliability. The Commission believes that a substantial body of evidence has emerged warranting consideration of possible actions to ensure that resources capable of providing primary frequency response are adequately maintained as the nation's resource mix continues to evolve.[92]

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[91] *Id*. at 5-6. *See also* Franks Testimony at pages 20, 21; page 22, lines 1-4.

[92] PFR NOI at PP 13-14. As Calpine explained in comments in Docket No. RM15-2-000:

> Historically, the predominance of large, base load thermal generation central stations have made system voltage and frequency relatively easy to maintain both pre- and post-contingency. This was due to the abundance of spinning mass inherent in conventional, large generation units. Additionally, due to regulated cost-of-service cost recovery, there was a willingness to incur increased wear and tear on units through responsive governor and droop settings.
>
> * * *
>
> With the advent of variable energy resources such as wind, photovoltaic solar, and similar technologies, conventional resources are being displaced and spinning mass is declining. Additionally, many generators have reduced their droop and governor control settings since there is no market to recover increased wear and tear costs. Absent change, the ability to arrest system frequency decay will become more difficult to accomplish. While the electronic power controls

With the expansion of variable energy resources such as wind, photovoltaic solar and similar technologies, conventional resources are being displaced,[93] and spinning mass is declining. Additionally, many generators have reduced their droop and governor control settings since there is no market to recover increased wear and tear costs.[94]

In January, 2014, the Commission approved Reliability Standard BAL-003-1,[95]which was later amended to include non-substantive revisions via errata filing and redesignated as BAL-003-1.1.[96] Among other things, BAL-003-1.1 requires Balancing Authorities to meet an annual frequency response measure, and compliance with this requirement begins December 1, 2016.[97] This standard requires each Balancing Authority or reserve sharing group to demonstrate

on variable energy resources may be technically capable of providing PFR at additional cost, interconnection practices have not historically required PFR.

Third-Party Provision of Primary Frequency Response Service, Docket No. RM15-2-000, Comments of Calpine Corporation at 3-4 (Apr. 27, 2015).

[93] According to the 2016 Annual Resource Adequacy Survey conducted by MISO and the Organization of MISO States, as much as 4.3 GW of generation in the MISO footprint may retire by the end of the summer of 2017. *See* Survey at 6, available here:https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2016/OMS-MISO%20Survey/2016OMS-MISOSurveyResults.pdf

[94] This issue is not confined to the Eastern Interconnection. The California ISO offers the following reasons for the decline in PFR capability: (1) steam turbine-generators operating on traditional “sliding pressure” control; (2) significant penetration of non-traditional generation, primarily wind and solar generation; (3) proportionally fewer frequency-responsive large motor loads, as the US becomes less of an industrial economy; (4) variable speed drives on motors do not provide traditional load damping; (5) some combustion turbine generator designs actually have a positive frequency characteristic, i.e., their output MWs go down when frequency drops; (6) generators having less inertia (less mass per MW of output); (7) fewer resources are carrying frequency responsive spinning reserves as the rules for the distribution of reserves have been relaxed; and (8) power plant control interaction removing or withdrawing governor action due to outer loop control which may be due to focus on plant performance with generation set points. *See* California Independent System Operator Corporation Frequency Response Issue Paper at 8-9 (Aug. 7, 2015), available here: https://www.caiso.com/Documents/IssuePaper_FrequencyResponse.pdf; *see also* Franks Testimony at page 9, lines 4-17.

[95] *Frequency Response and Frequency Bias Setting Reliability Standard*, 146 FERC ¶ 61,024 (2014) (“Order No. 794”). Reliability Standards proposed by NERC are submitted to the Commission for approval pursuant to section 215(d) of the FPA. *See*16 U.S.C. § 824o(d).

[96] *See N. Am. Elec. Reliability Corp*., Docket No. RD15-6-000, Delegated Letter Order (Nov. 13, 2015).

[97] Requirement R1 of BAL-003-1.1 requires each balancing authority to achieve an annual Frequency Response Measure that equals or exceeds its Frequency Response Obligation. The Frequency Response Measure is the median value of a balancing authority’s frequency response performance during selected events over the course of a year.

that it meets the required measure through the submission of a compliance form each year after the conclusion of the compliance year. The Commission has also instituted an NOI to further examine the issue in Docket No. RM16-6-000.[98]

While today on a regional basis, only the California Independent System Operator Corporation ("CAISO") is experiencing a material shortage of the ancillary services that support grid reliability (voltage and frequency control services) the other RTOs are expected to begin seeing this reduction as coal-fired generation retires and additional renewable resources and gas-fired generation are interconnected. In fact, MISO recently recognized a decline in frequency response in its own footprint.[99] The reliability of the bulk power system is at risk if an expedient remedy is not applied.[100]

IPL recognizes that in Order No. 794, the Commission directed NERC to submit a report by July, 2018 analyzing the availability of resources for each Balancing Authority and Frequency Response Sharing Group to meet their Frequency Response Obligation.[101] The Commission should not wait until the conclusion of this report to take the remedial action requested in this Complaint. It is unjust and unreasonable not to compensate resources for the PFR they contribute to the Balancing Authority Area. Stated another way, the HSS BESS is assisting

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98 *See* PFR NOI.

99 *See* MISO IPTF Presentation at 5-6 (March 10, 2010). Available here: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/IPTF/2016/20160310/20160310%20IPTF%20Item%2002%20Frequency%20Response.pdf

100 As is pointed out in NERC's January, 2016 paper Reliability Considerations or Clean Power Plan Development at page vi of the Preface, "in order to maintain an adequate level of reliability through this [Clean Power Plan implementation] transition, generation resources need to provide sufficient voltage control, frequency support, and ramping capability—essential components to the reliable operation of the BPS. It is necessary for policy makers to recognize the need for these services by ensuring that interconnection requirements, market mechanisms, or other reliability requirements provide sufficient means of adapting the system to accommodate large amounts of variable and/or distributed energy resources (DERs)." Available here:

http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Reliability%20Considerations%20for%20State%20CPP%20Plan%20Development%20Baseline%20Final.pdf.

101 Order No. 794 at P 60.

MISO in meeting its BAL-003-1.1 requirement without compensation. As described below, MISO has no requirement that Resources contribute to PFR. Thus, a lack of compensation enables inappropriate leaning on the PFR provided by certain resources.

e. The HSS BESS Is Providing PFR.

The HSS BESS has been set since its commercial operations date of May 20, 2016 to respond when frequency deviates from the standard[102] by .036 MHz (deadband).[103] This setting is consistent with the typical Governor setting for generators that provide PFR in the Eastern Interconnection.[104]

The HSS BESS employs software to manage nodes of Lithium ion batteries to instantaneously inject or withdraw energy.[105] The HSS BESS provides PFR automatically. It is critical to understand that the HSS BESS is *not* dispatched by MISO. The HSS BESS reaches it full programmed response in a second, unlike traditional Resources such as generators or even other types of storage such as flywheels or pumped storage, whose response begins in 10-60 seconds, reaching the desired response later. The HSS BESS' efficiency is designed to be 96

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[102] Or, it responds if there is a deviation from other frequency target set by MISO.

[103] Franks Testimony at page 9, line 6. The "deadband" parameter tells the resource when to respond. The "droop" parameter tells the resource the magnitude of response. The droop setting for the HSS BESS is initially 5% but will be reduced to 2.5% in the near future. Franks Testimony at page 9, lines 4-17.

[104] NERC Reliability Guideline Primary Frequency Control. The HSS BESS is capable of responding to a much smaller deviation should that be needed. Franks Testimony at page 9, lines 11-17. CAISO has reported that reducing the deadband to .017 Hz results in a significant improvement in frequency control. As a result, the ERCOT test of deadband reduction, NERC Standard BAL-001-TRE-1 — Primary Frequency Response in the ERCOT Region was implemented. This standard requires all generators other than steam and hydro to establish deadband at .017 Hz.

[105] As explained in the testimony of Lin Franks, the HSS BESS is a modular design comprised of eight(8) two and a half (2.5) MW Cores, each with thirty or more (30+) nodes. There are a total of 244 nodes. A node is a rack of battery trays and invertors. The system is monitored and controlled through SCADA ("Supervisory Control and Data Acquisition") and HMI ("Human Machine Interface"). It monitors over 20,000 data points in each Core. Each node contains 20 battery trays with 20 wafer batteries in each tray for a total of 9,600 lithium ion battery cells. One advantage of the modular design is that the State of Charge (SOC) of each node is managed separately allowing the device to be continuously charged sufficiently to provide continuous PFR. Some nodes may be charging while others are performing service. Franks Testimony at page 7, lines 10-16; page 9, lines 18-23; page 10, lines 1-18.

percent efficient, but it has performed at almost 100% efficiency to date. Traditional generators typically operate in the 60 percent efficiency range.[106]

Figure 2 – Performance of the HSS BESS during a sample of hours

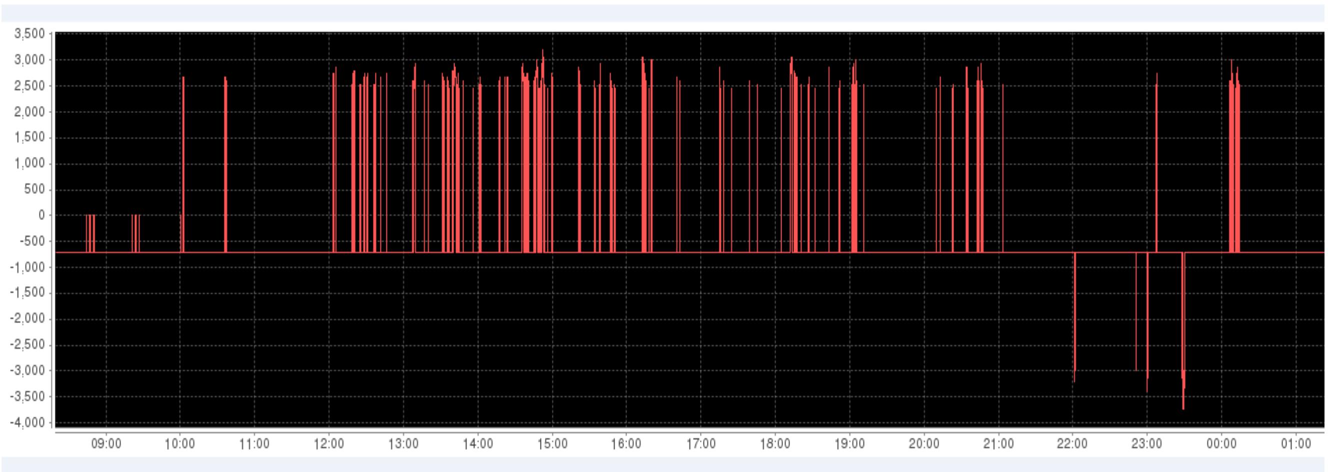

Figure 2 above (designated as Exhibit No. IPL-3 in the Franks testimony) illustrates the nearly instantaneous injections and withdrawal of the HSS BESS. It shows the performance of the HSS BESS during a sample of hours on during July 6, 2016. In this period, MISO had reduced the system frequency target below 60Hz in order to facilitate a "time error correction."

The tall vertical lines above the baseline show the battery injecting into the grid, reaching its directed output in one second in response to a lower than required frequency.[107] The tall vertical lines below the baseline show the battery withdrawing from the grid because the frequency was above the desired frequency level. The "withdrawal" shown on Figure 2 is not a

[106] Franks Testimony at page 11, lines 6-18. When providing PFR, the HSS BESS is at least 96% efficient. The difference between 100% and 96% (4%) is referred to as round trip loss which includes auxiliary power needed for HVAC and other normal "station power"- and "company use"- type services. *Id*.

[107] The operating software of this battery currently collects performance data every 2 seconds; however the battery responds to a frequency deviation in one second. Adjustments to the time increment of data collection is possible.

"withdrawal" needed to charge the battery. It is a mitigating action for a system frequency deviation.

f. Treatment of PFR Under the MISO Tariff.

The reliability-based requirement embodied within BAL-003-1.1 applies at the Balancing Authority level. Thus, MISO will be required to meet BAL-003-1.1 beginning December 1, 2016. As MISO's own presentation starkly states: "[t]here is no current requirement to provide frequency response," and "[t]here is no market mechanism to provide payment for frequency response."[108] MISO further admits, "[w]ith no economic benefit and no requirement, [the] majority of new generation provides no frequency response."[109] Thus, MISO's own assessment acknowledges that there is no incentive for Resources to provide PFR. Not surprisingly, MISO is noticing a trend of declining frequency response in the MISO region.[110] Notwithstanding the trend in declining frequency response within the region, MISO's comments to this Commission do not demonstrate any urgency in terms of attracting additional supply, and indeed seem to focus on (less efficient) generation resources only.[111] By contrast, the Grid Storage commenters point out that allowing grid operators to mandate Frequency Response from only generation effectively creates a zero price (not zero cost) competitor to these alternative resources and gives generators the ability to squelch new competition from innovative technologies. The elimination of a market (and potential market participants) precludes the ability to determine the most reliable and most cost effective solution to provide PFR.[112]

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[108] MISO Stakeholder Presentation to the IPTF, "Frequency Response," at 2 (Mar. 10, 2016).

[109] *Id*. at 5.

[110] *Id*. at 6.

[111] *See Essential Reliability Services and Evolving Bulk-Power System Primary Frequency Response*, Docket No. RM16-6-000, Comments of the Midcontinent Independent System Operator, Inc. (Apr. 25, 2016).

[112] *See Essential Reliability Services and Evolving Bulk-Power System Primary Frequency Response*, Docket No. RM16-6-000, Comments of Grid Storage Consulting, LLC at 3 (Apr. 25, 2016).

The Commission should act to address this decline in PFR before the situation becomes critical. Indeed, the MISO assessment may be repeated in other regions. The Commission's PFR NOI points out that any RTO/ISO that desires to explicitly procure and compensate PFR would need new tariff provisions, because no RTO/ISO currently defines or procures such a product.[113]

g. Proposed Compensation for PFR

(1) Proposed Payment for PFR

As stated earlier, IPL's burden in this case is to show that the current MISO Tariff is no longer be just and reasonable.[114] IPL does not have a dual burden to demonstrate the justness and reasonableness of an alternative Tariff provision or rate.[115] Nevertheless, in the interest of promoting a prompt resolution of this case, in which the HSS BESS is already interconnected and providing service today, IPL has developed an alternative approach to properly compensate resources providing PFR. As described in the testimony of Lin Franks, IPL's recommends that the Commission require MISO to:

(1) pay the LMP multiplied by the amount of MWhs of PFR injected in order to respond to under frequency deviations;.

(2) pay the LMP multiplied by the amount of MWhs of PFR absorbed in order to respond to over frequency deviations; and

(3) Apply a mileage factor of 2.9 times the amounts in (1) and (2) for faster responding resources to account for the benefits of faster performance; and

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113 PFR NOI at P 39.

114 16 U.S.C. § 824e(a).

115 16 U.S.C. § 824d; *FirstEnergy Service Co. v. FERC*, 758 F.3d 346, 353 (2014).

(4) adopt the entire structure MISO uses in day-ahead and real-time for the Secondary Frequency control dispatched Regulation market for devices providing such services automatically (not dispatched).[116]

As with any MISO market product, IPL would expect that experience, technological changes, and regulatory initiatives (including, but not limited to, FERC rulemakings) may require modifications to this approach. Nevertheless, IPL's proposal represents a reasonable means to compensate resources for the actual PFR they contribute to maintain MISO grid stability.

Indeed, IPL believes this to be a conservative, initial approach to introduce the unbundled pricing of the PFR service. For other Ancillary Services, MISO pays a capacity or opportunity cost for keeping the resource available if needed. MISO then pays the LMP if the resource is subsequently deployed. In its proposal, IPL is not including any availability payment.[117] If, and only if, the resource is deployed to mitigate over or under frequency would there be a payment. Similar to other deployments, the amount of actual energy service would be paid the LMP. In other words, a MWh of Energy deployed for PFR would be compensated at the same level as a MWh of Energy deployed for any other service in MISO.

IPL proposes that this approach be implemented immediately and continue for a period of six months. After six months time, MISO should be required to file a refined compensation

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[116] Testimony of Lin Franks at page 23.

[117] As stated by Lin Franks,

> In its proposal, IPL is not including any availability payment for the first six months as some time will be needed to adapt the settlement structure to automatic provision of frequency control. For the first six months when the resource responds automatically to mitigate over or under frequency would there be a payment at LMP multiplied by the benefits factor, but no payment for availability.

Franks Testimony at page 24, lines 10-21.

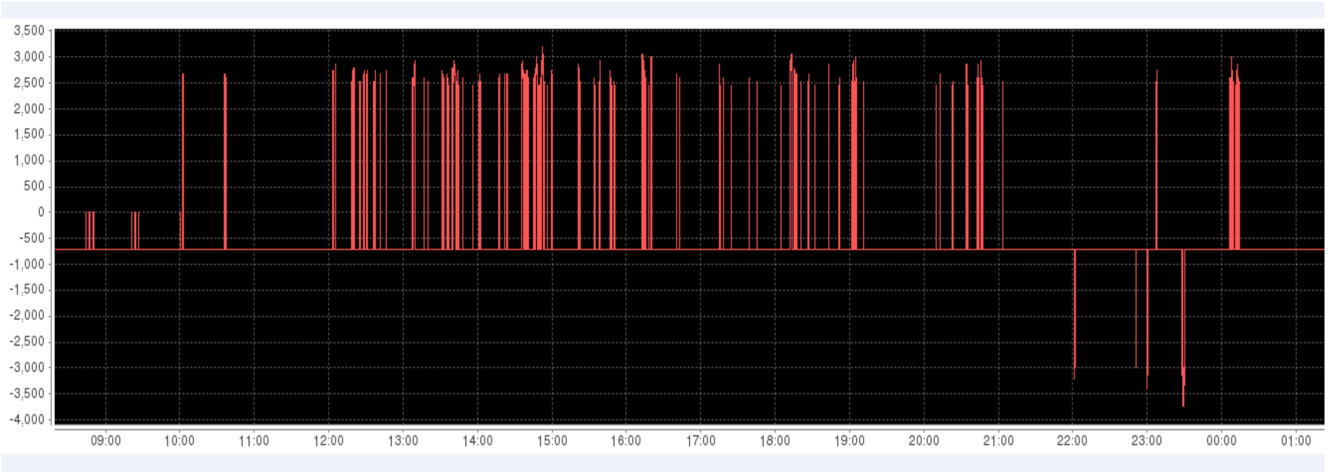
proposal based upon the unique circumstances within MISO. Given the benefit of experience, the 2.9 mileage factor may need to be adjusted, for example.

(2) Payment for Movement in Either Direction

In both cases -- injecting Energy to mitigate under-frequency or withdrawing Energy to alleviate over-frequency -- the unit is providing Frequency Control, an essential reliability service. For MISO to pay only for injections would create the wrong incentive for units only to provide half of what is needed for PFR. Moreover, paying for positive PFR and charging for withdrawals to mitigate high frequency inappropriately reduces the compensation that should be paid for services provided.[118] The same considerations should be accorded batteries providing PFR.

The following chart, from the Testimony of Lin Franks (Exhibit No. IPL-3) and displayed *supra* as Figure 2, illustrates the importance of proper frequency control in ***both*** directions.

[118] *Cf.*, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Docket No. RM11-7-000, Comments of the Organization of MISO States at 6 (May 2, 2011) (noting that proper incentives within an RTO requires compensation for movement in both directions without netting).



The vertical long lines over the baseline show the device injecting energy because the frequency was below the desired frequency. The vertical lines below the baseline show the device withdrawing energy from the grid because the frequency was above the desired frequency. Importantly, the withdrawal shown on the chart is not a "withdrawal" needed to charge the battery. It is a mitigating action for a system frequency deviation. Management of the SOC is performed and tracked separately from performance of PFR. The shorter vertical lines above the baseline (to the left on this chart) represent the only points in time where the array was charging.

Thus, using the example represented by this chart, the HSS BESS should only be charged LMP for the times represented by the shorter vertical lines above the baseline. For the other longer vertical lines, both over the baseline and below the baseline, the HSS BESS should be compensated. To do otherwise, would be unjust and unreasonable because it would fail to compensate the HSS BESS for the provision of an essential grid reliability service.

(3) Use of the 2.9 Performance Factor

Frequency Control is time-sensitive. In response to a sudden power imbalance, the faster the PFR can be deployed the sooner the nadir of the event will be arrested.[119] Fewer MWs of service from slower resources will be needed as a result.[120] Absent a resource-specific benefits or performance factor, there would be no difference in the payment for units with the faster response time and slower performers.

In PJM, a higher benefit factor is applied to the mileage rate for "REG D,"[121] the category of regulation developed for fast-acting resources, like batteries. Conceptually that factor accounts for the speed the resource responds to the 5-minute dispatch signal. Accordingly, the REG D benefits factor or mileage rate compensates somewhat for the vastly more expedient response. The REG D benefits factor of 2.9 was developed together with a separate dispatch signal and performance criterion. Compensation for the service rendered automatically is critical to incenting both more efficient response of generators and investment in state-of-the-art solutions like the HSS BESS by vertically integrated utilities, merchants, and transmission-only utilities. As the Commission intended with Order No. 755, better performing resources should be compensated at a better rate than lesser performing resources. This is necessary whether or not the resource is participating in a centralized market and dispatch or providing the service automatically as is the HSS BESS. Automatic and nearly-instantaneous response should be valued at a higher rate as the benefits to the system are greater. As stated in the PJM business practice manual:

> The benefits factor translates fast moving resource's MWs into traditional

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[119] Franks Testimony at page 25, lines 3-5.

[120] *Id*.

[121] *See* PJM Manual 11, Revision 84 a 76 (Effective Aug. 25, 2016). Available here: http://www.pjm.com/~/media/documents/manuals/m11.ashx

> MWs or Effective MWs. These Effective MWs reflect the rate of substitution between resources following the different regulation signals. For market clearing, each dynamic resource will be assigned a decreasing and unique benefits factor. The benefits factor of the offered resource or resource specific benefits factor is the marginal point on the benefits factor function that aligns with the last MW, adjusted by historical performance that specific resource will add to the dynamic resource stack.[122]

Further, the 2.9 factor is useful as it has already been accepted by the Commission in a neighboring RTO for a similar product. Because resources like the HSS BESS respond in a second and arrest developing problems very quickly, the 2.9 factor may, if anything, be too low. Nevertheless, in the interest of expeditiously establishing a reasonable initial payment formula, IPL urges the Commission to adopt this initial approach.

As explained by Lin Franks, and as discussed in the preceding section, IPL recommends that for an interim period of six months only MISO would apply the 2.9 factor to faster resources until MISO can develop an appropriate benefits factor for its own footprint. Each resource in the fast group should have its own benefits factor based on its own performance speed and availability.[123] The Commission should set a specific period, such as six months, for MISO to revisit compensation on compliance with specific factors for the units within its fleet.

(4) Penalty for Non-Performance

IPL agrees that there should be a penalty for non-performance.[124] Once a resource has committed to provide a certain MW quantity of PFR and has been certified as capable, the resource should be penalized if it fails to respond appropriately. The commitment to provide a certain level of PFR can be made day ahead even for automatic provision of service. In this case the commitment can be compensated as would any capacity payment. IPL recommends initially

122 *Id*.

123 *Id*. at page 24, lines 14-15.

124 *Id*. at page 25, lines 7-12.

using the same penalty structure that exists for the dispatched Regulation Service with modifications for automatic service provision.[125]

(5) Charge for "Filling" the Battery

IPL also supports a requirement that energy used to manage the SOC for the HSS BESS or any other battery be separately metered and charged the applicable LMP.[126]

(6) Comparison to DRR-II Compensation

In its proposal, IPL is not including any availability payment for the first six months as some time will be needed to adapt the settlement structure to automatic provision of frequency control. For the first six months when the resource responds to automatically mitigate over or under frequency, there would be a payment at LMP multiplied by the benefits factor, but no payment for availability.

MISO currently pays the LMP to DRR Type II resources that reduce load on the grid. Exhibit IPL-12 to the Franks Testimony is an excerpt from a MISO-produced Settlements Presentation that explains this payment logic.[127] The settlement of DRR Type II and the payment for reduction of load is explained in MISO's Market Settlements Overview beginning on slide 68. While the settlements presentation may look confusing, the settlement for Type II when reducing load on the grid is consistent with the simple explanation for Emergency Demand Response on slide 70. Thus, IPL's proposal is consistent with the existing process used to compensate DRR- Type II resources. Battery storage resources should be treated comparably, especially considering their level of efficiency.

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125 *Id*.

126 *Id*. at page 25, lines 13-18.

127 The entire presentation can be found here: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Training%20Materials/MP%20200/Market%20Settlements%20Training%20-%20Generation.pdf

B. In Addition to Providing for Compensation for PFR, the MISO Tariff Is Also No Longer Just and Reasonable Regarding The Provision of Regulation.

Taking the Order No. 888 construct underpinning Schedule 3 of Regulation and Frequency Response, the preceding discussion in Section V.A demonstrates that the PFR aspect of Schedule 3 should be unbundled and compensated separately. Regarding the remaining portion of Schedule 3, Regulating Service, the MISO Tariff is no longer just and reasonable with regard to this service as well, and the tariff should be reformed.

1. As A Practical Matter, Only Certain Generators or Flywheels Can Receive Compensation Under Current MISO Schedule 3.

As a practical matter, only generators with governors or flywheels can receive compensation under MISO's Schedule 3.[128] This circumstance is unduly discriminatory toward grid-scale batteries utilizing Lithium ion technology, and also provides an undue preference to traditional generators and flywheels.

Taking flywheels first, as discussed in the preceding section, the SER category was designed for flywheels, with a relatively slow one-hour discharge and one-hour re-charging parameter.[129] Thus, flywheels can provide Regulation as an SER and receive compensation.

Regarding generators with governors, the MISO market utilizes a co-optimized energy and ancillary services dispatch, meaning generators make offers and MISO dispatches generators in the most efficient manner, with the generators receiving compensation, including compensation for lost opportunity costs considering all services provided. Thus, generators who provide Regulation receive compensation for doing so, and can do so without fear of damaging

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[128] *See Electric Storage Participation in Regions With Organized Wholesale Electric* Markets, Docket No. AD16-20-000, Response of the Midcontinent Independent System Operator, Inc. at 2 (May 16, 2016) ("MISO initially addressed electric storage resources in 2008 by introducing the resource category of Stored Energy Resources (SERs). At that time, the SER classification pertained to short-term storage technology such as "fly-wheel," which the present Tariff limits to the provision of Regulating Service.").

[129] The fact that flywheels have not been installed (other than behind the meter) within MISO is a matter beyond the scope of this complaint.

their equipment because MISO respects operating parameters.[130] But, as explained in the preceding section and in the Franks Testimony, forcing the HSS BESS to provide Regulation would shorten the design life of the battery cells and would force the unit to be operated in a manner which deprives the grid (and customers) of the most useful characteristic of the unit, namely its ability to respond in a second to frequency deviations.

Regulation Qualified Resources include Resources that are capable of and have submitted Regulation Capacity Offers and Regulation Mileage Offers.[131] Importantly, Section 39.2.1B.A of MISO's Tariff states: "All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of supplying Regulating Reserve for a minimum continuous duration of sixty (60) minutes."[132] This requirement appears appropriate to flywheel technology or traditional generators, who are well-suited to provide Regulation over one-hour time frames. As discussed in the next section, however, for Lithium ion grid-scale batteries, being required to provide Regulation for a minimum of one-hour becomes problematic in that it damages the battery cells and shortens their life. Thus, the Commission should direct that MISO reform Section 39.2.1B.A of its Tariff to accommodate newer and more efficient technologies, such that Resources employing such technologies could submit Regulation Capacity Offers and Regulation Mileage Offers for less than one hour.

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[130] *See e.g.*, MISO Tariff at § 38.2.5.a.ii (no Market Participant shall be required to take any action inconsistent with Good Utility Practice); § 40.2.5.e (Values in Offers "shall reflect the actual known physical capabilities and characteristics of the Generation Resource and/or Demand Response Resource – Type II on which the Offer is based ….").

[131] MISO Tariff, Module A, § 1.R.

[132] MISO Tariff, § 39.2.1B.A.

2. Forcing The HSS BESS To Provide Regulation Under Schedule 3 of the MISO Tariff Will Shorten The Life of the Cells.

Forcing the HSS BESS to provide Regulation under Schedule 3 of the MISO Tariff and to be dispatched as an SER will damage the Lithium ion cells that store electrical energy. As Witness Franks explains, and as recounted in the background section *supra*, the SER resource category under MISO was designed specifically for flywheel technology.[133] The SER category would dispatch the HSS BESS at half-capacity continuously for one hour, and then send a negative signal for the following hour to charge.[134] And, as explained in the preceding section herein, Section 39.2.1B.A of the MISO Tariff states: "All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of supplying Regulating Reserve for a minimum continuous duration of sixty (60) minutes."[135]

The life expectancy of a battery cell as well as the provision of grid benefits is highly dependent upon appropriate use for the design. The HSS BESS design must optimize its SOC so that it is continuously available. For Lithium ion technology, life expectancy is also measured in number of expected cycles in the life of the battery. A "cycle" is the charge up to full capacity and then total (or nearly total) discharge of that capacity. To maximize the life of a Lithium ion battery, such cycling must be limited. Continuously maintaining a charge at, for example, 60%, rather than running the battery all the way down and then recharging all the way back up to 100%, will prolong the battery's life. The dispatch scenario for SER essentially causes the anticipated number of life cycles of the cells to be consumed in a much shorter time period than if the battery is operated properly. The HSS BESS cell life is anticipated to be approximately 10

133 Franks Testimony at page 27, lines 16-23.

134 *Id.*

135 MISO Tariff, § 39.2.1B.A.

years with proper operation. If dispatched under the SER resource procedures, IPL would expect the cell life to be only three years.[136]

Further, forcing Lithium ion batteries, and in particular, the HSS BESS, to be dispatched in such a manner – one hour injection and then one hour withdrawal – prevents the devices from being used in the most valuable manner. These circumstances are clearly unjust and unreasonable, unduly discriminatory and preferential, and should be remedied.

3. Batteries Should Not Be Charged the LMP When They Are Responding to Over-Generation (or providing "Regulation Down").

Consistent with the discussion above with respect to PFR, grid-scale batteries, or any other type of storage Resource, should not be charged for withdrawal of energy when that withdrawal is to mitigate frequency above the established parameters.[137] In other words, when a Resource is providing beneficial Regulation Down, the Resource should not be charged, but rather should be compensated. The resource is withdrawing energy to mitigate over-frequency conditions. Batteries responding to either positive or negative deviations in one second are actually providing more benefit on a MW basis than traditional resources and, therefore, should be compensated for this versatility and efficiency, not degraded because of outdated operating parameters.[138]

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[136] Franks Testimony at page 28, lines 22-23.

[137] Rather than restating the entire discussion, suffice it to say the same logic and reasoning, supported by the same exhibits, testimony and other evidence supports this point with respect to Regulation (this section) as well as PFR (discussed earlier).

[138] *See Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Docket No. RM11-7-000, Comments of the Organization of MISO States at 6 (May 2, 2011) (noting that proper incentives within an RTO requires compensation for movement in both directions without netting).

4. The Current Mileage Factor of One (1) Is Not Just and Reasonable.

The current mileage factor used in MISO, one (1), is no longer just and reasonable, and the Commission should act in this case to remedy this insufficient factor. The Commission can adopt the 2.9 factor used by PJM.

While Order No. 755 required more efficient resources to be compensated at a higher level for superior performance, MISO's implementation of Order No. 755 included a 1:1 ratio between regulating reserve mileage and regulating reserve.[139] MISO explained in its filing that it sampled historical AGC deployments to derive the 1:1 ratio, but admitted that there also were a number of dispatch intervals in which the 1:1 ratio did not hold.[140] The Commission noted that "given MISO's practice of dispatching faster-ramping resources first, a uniform deployment assumption might not accurately reflect the movement asked of different types of resources."[141] The Commission required MISO to submit an informational report which MISO filed in February, 2014.[142]

On November 19, 2012, MISO submitted Tariff amendments to address both the deployment assumptions and the deployment ratio.[143] MISO proposed to establish a monthly regulation deployment factor that is based on the ratio between the Regulating Mileage Target and the Regulating Reserve Dispatch Target, using actual regulation deployment data.[144] The Commission accepted MISO's proposal via Letter Order on January 25, 2013, and the Tariff

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139 *Midwest Indep. Transmission Sys. Operator, Inc*., 140 FERC ¶ 61, 224 at P 39 (2012).

140 *Id*.

141 *Id*.

142 *Id*.

143 *Midwest Indep Transmission Sys. Operator, Inc*., Docket No. ER13-420-000, Tariff Filing of the Midwest Independent Transmission System Operator, Inc. (Nov. 19, 2012).

144 *Id*. at 5.

changes were made effective on February 1, 2013.[145] Since that time, MISO has posted the ratio used in the market clearing each month. Since February, 2013, the ratio has been between 0.55 and 0.62.

According to MISO:

> the actual deployment ratio for fast ramping resources (with ramp rate more than 10 MW/Min) is higher than the actual deployment ratio for slow ramping resources (with ramp rate less than 3 MW/Min), the design results in higher Additional Regulating Mileage payments to fast-ramping resources. Moreover, fast-ramping resources also perform better than slow-ramping resources and, therefore, incur less performance penalty charges. These two factors provide fair compensation to resources that can provide better regulation service. Since the new design went into production, MISO has observed a slight shift of cleared regulation from slow-ramping resources to fast-ramping resources.[146]

IPL submits that changed circumstances require a change in findings by the Commission concerning the continued justness and reasonableness of the 1:1 mileage factor. As noted earlier, the HSS BESS is the first grid-scale Lithium ion battery installed in the MISO footprint. With the growth of grid-scale batteries, the technology options available to MISO to meet its Schedule 3 needs have changed, necessitating a reexamination of the compensation available. Clearly, as demonstrated by the Franks Testimony and accompanying exhibits and the experience to date, Lithium ion batteries can respond quickly and can arrest a developing frequency problem on the grid far more quickly than a conventional generator. Consistent with Order No. 755, faster-responding resources should be rewarded with a higher mileage factor, irrespective of performance penalty considerations. Additionally, the 2.9 factor has been accepted by the

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[145] *Midwest Indep Transmission Sys. Operator, Inc*., Docket No. ER13-420-000, Delegated Letter Order (Jan. 25, 2013).

[146] *Midcontinent Indep. Sys. Operator Inc*., Docket No. ER12-1664-000, Informational Report of the Midcontinent Independent System Operator, Inc. at 2-3 (Feb. 18, 2014).

Commission for a neighboring region and that neighboring region has been successful in attracting significant investment in batteries.

C. The MISO Tariff Should Be Reformed To Permit Grid-Scale Batteries To Provide The Full Range of Products They Are Capable of Providing.

1. Conforming Changes to the MISO Tariff Should Be Made to Allow for Any Resource to Provide Any Product It is Capable of Providing.

As discussed in the Franks Testimony and earlier herein, the MISO dispatch algorithm, Tariff, and business practice manuals should be overhauled. The overall approach as currently constituted describes a resource type and then specifies what product a resource is permitted to provide. IPL submits that the approach should be that so long as a resource can demonstrate the ability to provide a service, it should be permitted to do so. As explained in the next section, the SER category provides a prime example of flaws in the current approach.

2. The MISO Definition of SER Should Be Changed, or New Definitions Should Be Developed For Lithium Ion Batteries and Other New Technologies.

The MISO SER definition should be changed to reflect changes in the marketplace, including technological changes, such as the deployment of grid-scale Lithium ion batteries. The current definition is designed solely for flywheel technology. SERs are defined as "[a] Resource capable of supplying Regulating Reserve, but not Energy Contingency Reserve, Up Ramp Capability, and Down Ramp Capability through the short-term storage and discharge of electrical Energy in response to Setpoint Instructions."[147] While that definition on the surface may appear innocuous and inclusive, in practice, the resource definition leads to very prescriptive modeling and dispatch for the operating characteristics of specific technologies. This approach to resources does not permit timely adaptation to changes in technology.

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[147] MISO Tariff, Module A, § 1.S. definitions, "Stored Energy Resource."

The HSS BESS is a highly versatile device that can be configured to meet a large variety of identified needs.[148] While the HSS BESS can provide PFR automatically and more efficiently than traditional generators, in the event that other services were needed, the HSS BESS could provide those services as well. For instance, the HSS BESS also meets the definition of "Load Modifying Resource" under the MISO Tariff and is capable of delivering 5 MW of Energy for four continuous hours.[149] Thus, the HSS BESS could qualify under Module E of MISO's Tariff to provide 5 MW of capacity or Planning Reserve Margin Requirement in MISO parlance. Additionally, the HSS BESS can provide Energy and Regulating Reserve service if needed. As explained earlier, under current MISO operations, if the HSS BESS were to be called upon regularly to provide such services and do so in conformity with the current SER resource category, it would shorten the life of the cells. Yet, it is important to note that the device is *capable* of providing capacity, Energy and Regulation, and there may be times when it is preferable for the device to provide such services in lieu of PFR. Yet, if the HSS BESS opted for the SER category, the HSS BESS is only *permitted* to provide Regulation.

The MISO Tariff should be flexible enough to allow for all resources, regardless of technology, to provide and be compensated for the full range of services that they can provide. As currently worded, the SER definition unduly discriminates against flexible Resources making use of storage capabilities that can provide a full range of services.

VI. RELIEF REQUESTED

The Commission should find that the MISO Tariff is unjust and unreasonable, unduly discriminatory or preferential for the reasons discussed *supra*. The Commission should also

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148 Franks Testimony at page 13, lines 16-17.

149 *Id*. at lines 17-20.

direct that MISO implement the proposed fixes regarding compensation for PFR as soon as possible (by year end), and also direct changes to the Tariff to address the infirmities in the Tariff pertaining to Regulation and what services SERs can provide. Such additional changes should be developed within six months and implemented not more than one year from the date of a Commission order on the merits.

VII. ADDITIONAL INFORMATION

A. Identification of Violation of Statutory Standards or Regulatory Requirements (18 C.F.R. § 385.206(b)(1))

Section 206 of the FPA prohibits "any rule, regulation, practice, or contract affecting such rate, charge, or classification" that is unjust and unreasonable or unduly discriminatory or preferential."[150] As described more fully throughout this Complaint, the MISO Tariff is no longer just and reasonable and is unduly discriminatory and preferential because it fails to properly account for currently-available grid-scale battery storage devices, as compared to generators providing such service. This effectively prevents the HSS BESS from being compensated for PFR and from participating in the MISO markets.

B. Explanation of the Violation (18 C.F.R. § 385.206(b)(2))

As described more fully throughout this Complaint, the MISO Tariff effectively prevents the HSS BESS from being compensated for PFR and from participating in the MISO markets, in violation of Sections 205 and 206 of the FPA.

C. Economic Interest Presented (18 C.F.R. § 385.206(b)(3))

As described more fully in this Complaint, under the current MISO Tariff, and in light of current MISO business practices and the software that MISO employs, the HSS BESS cannot effectively participate in any MISO market, without risking harm to its equipment. Thus, absent

[150] 18 U.S.C. § 824e(a).

action pursuant to this complaint, the HSS BESS cannot derive revenues from the wholesale markets.

D. Financial Impact ((18 C.F.R. § 385.206(b)(4))

See Section VII.C, *supra*.

E. Practical Impact (18 C.F.R. § 385.206(b)(5))

The practical impact of the current state of the MISO Tariff is that the HSS BESS is forced to provide PFR without compensation, and prevented from providing Regulation or any other MISO product or service, without risking physical harm to its equipment.

F. Other Pending Proceedings (18 C.F.R. § 385.206(b)(6))

To the best of IPL's knowledge, there are no other pending proceedings relating directly to the specific provisions within the MISO Tariff discussed herein, provisions which prevent the HSS BESS from effectively participating in the MISO markets. The Commission has issued a Notice of Inquiry in Docket No. RM16-6-000, *Essential Reliability Services and the Evolving Bulk Power System – Primary Frequency Response*, which raises related issues in a generic manner, such as the possibility of providing for compensation for Primary Frequency Response as a separate ancillary service.

Additionally, in Docket No. AD16-25-000, *Utilization In the Organized Markets of Electric Storage Resources as Transmission Assets Compensated Through Transmission Rates, for Grid Support Services Compensated in Other Ways, and for Multiple* Services, the Commission issued a "Notice of Technical Conference" on September 30, 2016. The technical conference is scheduled for November 9, 2016. The technical conference will address cost recovery models for storage being treated as transmission, storage being treated like generation, and practical considerations for electric storage providing multiple services.

G. Relief Requested (18 C.F.R. § 385.206(b)(7))

The relief requested by IPL is fully discussed at Sections V and Section VI, *supra*. IPL respectfully requests that the Commission find that various aspects of the MISO Tariff are unjust and unreasonable, unduly discriminatory, and unduly preferential. While IPL also offers proposed fixes for the identified unjust and unreasonable portions of the Tariff, IPL notes that its burden under FPA Section 206 is to show that an existing Tariff provision may be unjust and unreasonable, but IPL does not need to also provide a just and reasonable alternative. Nevertheless, the Commission could summarily adopt the proposed fixes discussed herein.

H. Attachments (18 C.F.R. § 385.206(b)(8))

The following attachments are included herein:

- Attachment A, Testimony of Lin Franks; and
- Attachment B, Form of Notice.

I. Other Processes to Resolve Complaint (18 C.F.R. § 385.206(b)(9)

This matter is properly before the Commission. IPL has sought in good faith to work through the MISO stakeholder process, and has sought to work directly with MISO, to address the issues raised herein. The issues raised herein relate to updating the MISO Tariff to accommodate new technology that has outpaced the current text of the MISO Tariff. After attempting to get MISO to engage meaningfully for over one and one-half years, MISO announced the start of a new stakeholder process in January, 2016.[151] Given that the HSS BESS has been in commercial operation since May 20, 2016, it is impractical and unjust and unreasonable to expect IPL to wade through a multi-year stakeholder process while its cutting

[151] *See* Presentation from MISO Energy Storage Workshop (Jan. 5, 2016), available here: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2016/20160105/20160105%20MSC%20Item%2006%20Energy%20Storage%20Workshop.pdf

edge device does not receive compensation for the PFR service it provides and is effectively prohibited from providing other services.

Regarding the dispute resolution procedures contained at Attachment HH of the MISO Tariff, Attachment HH states in pertinent part, "[n]othing in these Dispute Resolution Procedures is intended to restrict or expand existing state laws or regulatory authority nor shall anything in these Dispute Resolution Procedures restrict the rights of any Party to file a complaint with the Commission under relevant provisions of the Federal Power Act ("FPA")." Thus, Attachment HH does not restrict IPL's right to file this complaint.

Further, the Attachment HH dispute resolution provisions are impractical in this case, where IPL seeks to change several provisions of the existing MISO Tariff and requests other procedural relief as described, *supra*. MISO announced that it was initiating a full-blown stakeholder process in early January 2016, which among other things, seeks feedback from stakeholders regarding the future treatment of storage generally and what Tariff changes should be considered.[152] Stated another way, the Complaint does not raise a bilateral issue between two market participants, or some other issue, that is amenable to resolution through the dispute resolution procedures contained within Attachment HH. Thus, IPL has proceeded to file this complaint.

J. Notice of Complaint 18 C.F.R. § 385.206(b)(10)

A form of notice is attached hereto as Attachment B.

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152 *Id.*

VIII. CONCLUSION

Based on the foregoing, IPL respectfully requests that the Commission grant the relief requested in this Complaint on an expedited basis.

Respectfully submitted,

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Counsel for Indianapolis Power & Light Company

Dated: October 21, 2016
Washington, D.C.

ATTACHMENT A

TESTIMONY OF LIN S. FRANKS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Indianapolis Power & Light Company	)	**Docket No. EL17-_______**
	)	
	)	

TESTIMONY OF

LIN S. FRANKS

INDIANAPOLIS POWER & LIGHT COMPANY

Filed: October 21, 2016

TESTIMONY OF
LIN S. FRANKS
INDIANAPOLIS POWER & LIGHT COMPANY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Lin S. Franks. My business address is One Monument Circle, Indianapolis, Indiana 46204.

Q. By whom and in what capacity are you currently employed?

A. For approximately twelve years I have been the Senior Strategist, RTO, FERC and Compliance Initiatives for Indianapolis Power & Light Company ("IPL"). IPL is a subsidiary of AES Corporation ("AES"). On behalf of AES I am the coordinator of points of view of all AES U.S. entities relative to batteries under Federal Energy Regulatory Commission ("FERC" or the "Commission") jurisdiction and responsible for drafting collective AES company comments, protests, and rulemaking responses to be filed with the Commission.

As part of IPL's active engagement with the Midcontinent Independent System Operator, Inc. ("MISO") Stakeholder process, I represent IPL with respect to policy, market structure, reliability, and transmission issues. For over two years I have been working toward the creation of appropriate tariff rules and business practices to facilitate interconnection and utilization of battery energy storage devices in MISO. Rules that recognize the unique operating characteristics of batteries are needed for the footprint to realize the reliability benefits of this versatile and valuable technology. I have spearheaded the integration of the first grid-scale battery into the MISO footprint, the IPL Advancion® Energy Storage Array, also known as the Harding Street Battery Energy

Storage System or "HSS BESS," navigating through all existing tariff, business practice, and study processes that are designed for generators, renewable resources, and other energy storage technologies, in particular flywheels. I have shared the identified challenges with MISO, stakeholders, and other interested parties through the stakeholder process and through frequent ad hoc meetings throughout the process (Exhibit No. IPL-7). The HSS BESS is now in operation, providing Frequency Control Services ("FCS") automatically. While the automatic response can occur throughout the Frequency Control continuum, I will use the term Primary Frequency Response ("PFR"), which is also known in some contexts as "Primary Frequency Control," to denote the automatic response of the HSS BESS to deviations in the MISO system frequency for all NERC defined FCS. IPL continues to share information openly with all interested parties, including providing tours of the facility, sharing of performance charts, and education on the operating characteristics of the technology (Exhibit No. IPL-8). IPL intends to continue this outreach and transparency for the foreseeable future.

Q. Please summarize your MISO and professional background.

A. On behalf of IPL, I was the sponsor and Chairman of the Electric and Natural Gas Coordination Task Force from its beginning in 2012 until September 2015. I previously served as the Chair of the MISO Ancillary Services Task Force and as the Chair of the State Ratemaking Study Group, the Long-Term FTR and Planning Task Force, the Supply Adequacy Working Group, and the Stakeholder Governance Working Group. I also served for a term as the Vice Chair of the Interconnection Process Task Force.

I have more than forty years of industry experience in the United States and Western European energy industries with a focus on hub and market design, operations, business strategy as well as risk management for both the natural gas and electricity sectors. I have held both line and officer positions in the electricity and natural gas sectors and contributed to the success of the two most notable natural gas hubs/market centers in the world, Henry Hub and Zeebrugge. My natural gas experience includes designing and drilling natural gas wells, physical and financial trading of hydrocarbons as well as hub and pipeline operations. In the electricity industry, I have experience in real-time operations, resource and transmission planning, regulatory and North American Electric Reliability Corporation ("NERC") compliance, as well as in-depth understanding of MISO processes and business practices. I have recently been accepted as a member of the Essential Reliability Services Subcommittee. I was a contributing author in a book published by Risk Publication, "The US Power Market" and the March 2000, "Telecommunications Revolution." I also contributed to the Energy Publishing Enterprises 2000 publication "Energy Derivatives: Trading Emerging Markets."

As a consultant I have worked with natural gas and electric utility clients globally to assist them in successful transition to a competitive business environment.

Q. Have you previously testified in proceedings involving the Federal Energy Regulatory Commission?

A. Yes. I have submitted testimony in Docket Nos. EL14-70-000.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the background and facts relevant to IPL's decision to develop the HSS BESS and IPL's efforts to work with MISO and the MISO stakeholders for more than two and a half years to pave a path for Lithium ion batteries to be appropriately utilized and compensated for the services they provide. My testimony identifies the challenges posed by MISO's current market design and tariff. IPL's multi-year effort has resulted in a comprehensive understanding of the current MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"), business practices, and commercial model limitations that are impediments to appropriate integration of this state-of-the-art technology. My testimony also proposes both short-term solutions that can be implemented expeditiously with respect to PFR and longer-term recommendations to enable Secondary Frequency Control (referred to in MISO as Regulating Reserve) market participation for batteries and for emerging technologies.

Currently, the MISO Tariff, business practices, and software design do not provide a viable path for Lithium ion batteries to participate in the Secondary Frequency Control (Regulating Services) market, nor do they provide compensation for any automatically-provided PFR. The HSS BESS was placed into commercial service on May 20, 2016. The unit is set up to respond to MISO system frequency deviations of 0.036 Hz or greater across the FCS continuum. This is the NERC-recommended deadband setting for the Eastern Interconnection. The response time, efficiency, and availability of the HSS BESS are far superior to any generator in the MISO footprint, yet the HSS BESS is not paid for the benefits it provides. For the past two and half years, IPL has been, and remains, focused on providing a reasonable and equitable path to successful interconnection and effective utilization of batteries for the benefit of IPL's native load customers, as well as the grid. The path we hope to create with the Commission's help will encourage future installations of batteries and may encourage an increase in existing resources supporting the reliability needs of the Bulk Power System

("BPS"). In particular, IPL believes our proposed solution will help to arrest the decline in PFR in MISO.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- Exhibit No. IPL-1 – Harding Street Station Battery Energy Storage System Components;
- Exhibit No. IPL-2 – NERC Frequency Control Time Continuum Table;
- Exhibit No. IPL-3 – Performance of the HSS BESS During a Sample of Hours on July 6, 2016;
- Exhibit No. IPL-4 – NERC Reliability Guideline – Primary Frequency Control;
- Exhibit No. IPL-5 – February 18, 2014 Informational Report of MISO (Docket No. ER12-1664-000);
- Exhibit No. IPL-6 – Essential Reliability Services Task Force Measures Framework Report;
- Exhibit No. IPL-7 – Non-Exhaustive List of IPL/AES Stakeholder Presentations
- Exhibit No. IPL-8 – Record of HSS BESS Tours
- Exhibit No. IPL-9 – March 10, 2016 Interconnection Process Task Force ('IPTF") Presentation on Frequency Response;
- Exhibit No. IPL-10 – May 1, 2011 National Energy Technology Laboratory Report "Frequency Instability Problems in North American Interconnections;"
- Exhibit No. IPL-11 – Whitepaper on Integrating Short-term Stored Energy Resource into MISO Markets;
- Exhibit No. IPL-12 – Excerpt from Market Settlements Presentation; and

- Exhibit No. IPL-13 – PJM Manual 11: Energy & Ancillary Services Market Operations, Section 3: Overview of the PJM Regulation Market.

II. IPL'S DECISION TO BUILD THE HSS BESS

Q. What is the Harding Street Station Battery Energy Storage System?

A. HSS BESS is a 20 MW or Flexible 40 Lithium ion battery designed to continuously provide automatic response to MISO system frequency deviations from the standard of 0.036 Hz or more. The term "Flexible 40 MW" means that the battery can inject 20 MWs of stored energy and can withdraw 20 MWs of energy for a total range of 40 MWs when providing PFR. The HSS BESS automatically responds to deviations by either injecting or withdrawing energy to contribute to the mitigation of a frequency deviation and to maintain system stability.

The HSS BESS is a modular design comprised of eight (8) two and a half (2.5) MW cores, each with thirty or more (30+) nodes. There are a total of 244 nodes. A node is a rack of battery trays and invertors. The system is monitored and controlled through Supervisory Control and Data Acquisition ("SCADA") and Human Machine Interface ("HMI"). It monitors over 20,000 data points in each core. Each node contains 20 battery trays with 20 wafer batteries in each tray for a total of 97,600 Lithium ion battery cells. Exhibit No. IPL-1 contains images illustrating these components.

Q. What is Frequency Control Service (FCS)?

A. Frequency Control (or, when referring to Frequency Control Services, "FCS") as defined by NERC is a time continuum. This continuum is summarized in the Table included on Exhibit No. IPL-2, which lists the specific services that constitute "FCS."

Frequency Control is a time sensitive process. The longer it takes to mitigate a deviation, the more MWs are required. MISO and all other RTOs set target frequency to elicit an automatic response from on-line generators with active Governors and additional resources capable of providing the service, including the HSS BESS.

Q. Can you give an example of how the HSS BESS is providing automatic PFR?

A. Yes. For example, Exhibit No. IPL-3 shows the performance of the HSS BESS during a sample of hours on July 6, 2016. The vertical lines above the baseline show the device injecting energy into the grid and reaching its fully-directed output in approximately one second, in response to a lower-than-required grid frequency. The vertical lines below the baseline show the device withdrawing energy from the grid because the frequency was above the desired frequency. Importantly, the "withdrawal" shown on this chart is not a "withdrawal" needed to charge the battery. It is a mitigating action for a system frequency deviation. Management of the state of charge ("SOC") is performed and tracked separately from performance of PFR.

Since its commercial operation date of May 20, 2016, the HSS BESS has been providing PFR, responding when MISO system frequency deviates from the target set by MISO by 0.036 MHz (deadband). This setting is consistent with the typical governor deadband setting and within NERC's guidelines for generators providing PFR in the Eastern Interconnection, as evidenced by the NERC Reliability Guideline for Primary Frequency Control, attached hereto as Exhibit No. IPL-4. The separate service as defined by NERC of "Primary Frequency Control" is another name for Primary Frequency Response. In the NERC continuum of frequency control services it is the first action taken and is always an automatic, not dispatched, service. Generators with governor controls and the HSS BESS provide all frequency control services in the NERC-defined continuum automatically. They merely react as directed to frequency deviations without regard to cause of the deviation. Therefore, for the purpose of my testimony I use the term "PFR" to designate all frequency control services provided automatically and not dispatched.

The terms "deadband" and "droop" refer the settings used to direct governor response. The "deadband" parameter tells the resource when to respond, such as when frequency deviates by .036 Hertz. The "droop" parameter tells the resource at what magnitude to respond. For generators, the response recommended by NERC is only a small percentage of the generator's capacity so that all generators share in the responsibility and are still dedicated to providing energy through markets. The HSS BESS does not provide energy through markets. It is not a generator. It is designed to provide frequency control services to help maintain a stable grid. The current droop setting for the HSS BESS is 5% so it does not respond to deviations at its full capacity. This droop setting is the NERC-recommended droop for generators with governor controls in the Eastern Interconnection. However, since the HSS BESS was designed to provide 20 MWs of frequency control, a droop setting of near zero is needed to elicit a response at full capacity. We will reduce the droop setting to near zero once there is payment for the services provided.

Q. Please describe in more detail what you mean by SOC.

A. One advantage of the modular design of this device is that the SOC of the nodes is optimized, allowing the device to be continuously charged sufficiently to provide continuous service. Another advantage of this system and the Advancion® operating software is that a "withdrawal of energy" from the MISO system to mitigate a frequency deviation is accounted for separately from withdrawing as part of the SOC management.

SOC is managed so that even if the battery is 50% charged it can still provide 20 MWs of nearly instantaneous injection or withdrawal. Conceptually this is similar to a car. The car can go 80 mph even if the gas tank is not full. The power (20 MW) is like the 80 mph speed capability and the gas tank is like the SOC (MWh). In this analogy, our car can still go 80 mph when the gas tank is full, almost empty, or anywhere in between. When the tank is nearly empty, however, the car has to slow down to conserve fuel until it reaches a filling station. So if the battery was operated so that all nodes were nearly depleted at the same time the MW injection might be lower than its full capacity. The proprietary operating software allows the battery to maintain a target charge level continuously. The SOC for the HSS BESS is managed according to the anticipated tasks it will be asked to perform in a 24-hour period. This is similar to having a list of errands to run and determining that if the tank in your car is half-full, you have enough gas to perform all the tasks. A fundamental difference between the battery and the car in the analogy is that the battery does not have to stop operating to refuel. Some nodes in the battery can be charging while others are performing service, and instead of one gas tank, it has 244. The SOC is managed so that the array is constantly maintaining its target SOC while performing service. It is this feature that provides the unique benefit of being continuously charged and continuously available to provide service.

Q. Why did IPL build the HSS BESS?

A. In the normal course of IPL's transmission and resource planning process, IPL considers and plans for the provision of essential reliability services (frequency and voltage control) necessary to provide reliable service to its native load customers every hour of every day. As the resource mix in the Eastern Interconnection changes to include more wind, solar, and gas-fired generation, IPL has sought solutions to the provision of essential reliability services for both frequency and voltage control that would continue to provide benefits to our customers as the grid continues to change. IPL chose to build a static var compensator for state-of-the-art voltage control and the HSS BESS for state-of-the-art Frequency Control.

When providing PFR, the HSS BESS is designed to be 96% efficient. The efficiency rating assumes continuous availability with appropriate SOC management. In contrast, the efficiency of all traditional generation in MISO in the provision of Secondary Frequency Control through the co-optimized market product "Regulating Reserve" is on average 60%. This value, taken from MISO's February 18, 2014 Informational Report filed in Docket No. ER12-1664-000, is also based upon the generation fleet's ability to perform to the requirements for response to the base point in the timeframe directed. MISO's February 18, 2014 Informational Report is attached hereto as Exhibit No. IPL-5. Generators may begin to respond to an event in 10-60 seconds, but can take longer to achieve the directed base point. As the HSS BESS responds in one second at its full directed capacity, and is at least 96% efficient, its performance far exceeds the generator-specific requirements in the current MISO Tariff for provision of Secondary Frequency Control. The quantity of energy required to mitigate a deviation in frequency increases with time. So Lithium ion batteries installed in the footprint can reduce the MWs needed to respond to a frequency deviation anywhere along the FCS continuum. The increase over time in MWs needed to respond is similar to the amount of force needed to stop a car rolling downhill. Imagine that you have a car parked at the top of a sloping driveway and you forget to set the parking brake.

A reasonably strong person may be able to stop the car from an uncontrolled roll down the driveway if he or she catches it immediately. However, if the car rolls down the driveway for a period of time, it will take many strong people to stop the car, if they can do it at all.

Q. What were additional factors behind IPL's decision to build the HSS BESS?

A. As discussed in the December 2015 NERC publication entitled "Essential Reliability Services Task Force Measures Framework Report," attached hereto as Exhibit No. IPL-6, the generation fleet in the United States is changing dramatically to one with a greater reliance upon renewables. While the environmental benefits of this change in the generation mix have been endlessly studied and broadcasted for years, the impact on grid reliability due to a reduction in ancillary services capability has just recently been elevated more broadly as an associated risk by NERC. In December, 2015 NERC recommended steps to gather data and study/forecast the needs going forward. While today on a regional basis, only CAISO is experiencing a material shortage of the ancillary services that support grid reliability (frequency and voltage support), the other RTOs are expected to begin seeing this reduction as coal-fired generation retires and additional renewable resources and gas-fired generation are interconnected. In fact, MISO recently recognized a decline in PFR in its own footprint (please see Exhibit No. IPL-9). While the RTOs other than CAISO report that they currently believe they have sufficient PFR to meet their obligation under BAL003-1.1 with additional resource changes anticipated for the near and foreseeable future, that sufficiency is likely to evaporate. Regulatory, Tariff, business practices, and software changes take years to finalize. The reliability of the BPS could be at risk if an expedient remedy is not applied.

IPL, like the vast majority of other utilities in the MISO footprint, is a utility with an obligation to serve native load customers reliably every hour of every day. IPL is also a Local Balancing Authority ("LBA") in MISO. As a Balancing Authority, IPL must meet NERC standards and follow NERC guidelines. The obligation includes compliance with NERC Standard BAL-003-1.1. While the obligation to provide a prescribed amount of PFR under this standard is MISO's, they neither own nor control the assets capable of providing PFR. LBAs and other generation owners must contribute for MISO to meet its obligation. BAL-003-1.1 requires resource owners to contribute to the provision of PFR. MISO measures the contribution of each resource in the footprint toward meeting the standards. For IPL and other utilities with an obligation to serve native load customers reliably, PFR is essential to meeting the obligation to our customers. IPL, like other utility members of MISO, plans for the provision of essential reliability services needed to continue to serve our customers reliably, either by self-supply or as part of the services sharing group of the MISO footprint.

Q. Is the HSS BESS capable of providing services other than PFR?

A. Yes. The HSS BESS is a highly-versatile device that can be configured to meet a large variety of identified needs. The HSS BESS meets the MISO definition of a "Load Modifying Resource" capable of delivering 5 MW of energy for four continuous hours and, therefore, can be used to meet 5 MW of the Planning Reserve Margin Requirement under Module E of the MISO Tariff.

In addition, if registered as a "Stored Energy Resource" or "SER" the HSS BESS could qualify to provide Regulating Service under the MISO Tariff. I will explain later how the MISO's Tariff and SER dispatch protocols act to prevent IPL from being able to offer this service, without damaging the battery or being subject to a financial loss. While there are several definitions in the MISO Tariff that describe various Stored Energy Resources, none address Lithium ion batteries or respect the operating characteristics of this technology. The generic category "Stored Energy Resource" includes a wide variety of technologies with vastly different operating characteristics. The MISO Stored Energy Resource definition, business rules, and dispatch scenarios were designed for one specific technology - flywheel technology and operating characteristics. Currently, SERs may only provide Regulation and are not permitted under the MISO Tariff to participate in the other Energy or Ancillary Services markets, nor to receive capacity accreditation. While modifying the Tariff definition and related business rules to accommodate Lithium ion battery technology might be accomplished in a reasonable amount of time, changing all of the software used for modeling and dispatch, including capital budget processes, can take several years. Given the long list of issues MISO and its stakeholders are addressing currently, we estimate the timeline to be around five years without Commission assistance. As the HSS BESS is in service and providing services without compensation, this is too long.

III. IPL'S EFFORTS TO ADDRESS ISSUES ASSOCIATED WITH DEPLOYMENT OF BATTERIES PRIOR TO FILING THIS COMPLAINT

Q. What are the primary issues IPL has encountered in trying to deploy the HSS BESS?

A. For more than two and a half years, IPL has worked collaboratively with MISO regarding the interconnection rules, Tariff modifications, and system enhancements needed to utilize batteries in the MISO system. However, given the current regulatory and Tariff structure, this collaboration did not result in a solution. IPL seeks to address the following critical issues in this complaint:

First and foremost, even though PFR is an essential reliability service, MISO does not compensate those suppliers that provide PFR. For all other Ancillary Services, MISO provides compensation for both the capacity to provide the Ancillary Service *and* for any energy utilized in real-time. Historically, PFR was bundled with Regulation Reserve under Schedule 3 of the Commission's Open Access Transmission Tariff based on the expectation that the same facilities (generators) would provide both services. With the development of grid-scale batteries and other new technologies, this is no longer the case. As shown in Exhibit No. IPL-2, the HSS BESS is being deployed to keep MISO's frequency within NERC standards. IPL should be compensated for this service. Any revenue received will flow back to IPL's native load customers as we will ask those customers to support the costs associated with this highly-efficient device.

Second, the Commission should order MISO to expedite a series of longer-term initiatives to better utilize Lithium ion batteries in markets it administers. With respect to Regulating Service, MISO should be directed to develop a Lithium ion battery technology-appropriate dispatch protocol. The dispatch protocol must not degrade the useful life of the battery's cells or otherwise harm the device. The structure must permit the battery owner, through the device sophisticated software to manage the SOC and allow the footprint to benefit from the unique benefits of this fast-response device. MISO should also be required to revise the compensation methodology to include payment for performance for fast devices such as the HSS BESS and to compensate the device for both injection and withdrawal when providing service. SOC management should of course pay the Locational Marginal Price ("LMP").

Finally, the MISO Tariff should be revised to permit batteries and all resources to provide any service that they have the technical ability to support. The HSS BESS is technically capable of providing all the ancillary services defined in the MISO Tariff, but is currently not permitted to do so.

Q. Describe the efforts made to continuously inform the MISO stakeholders, and explain the HSS BESS interconnection process and why it is not participating in the MISO-administered co-optimized energy and the Ancillary Services market for Regulating Reserve.

A. IPL engaged with MISO on July 17, 2014 in the first step to the interconnection queue process, with a "pre-queue" meeting. The purpose of that meeting was to talk frankly about the Lithium ion battery, its purpose, and to devise a plan to navigate the queue process by the desired in-service date, March 31, 2016. As the project moved forward, IPL provided updates and presentations to stakeholders and other interested parties. IPL presented to and participated in the related discussions in the Interconnection Process Task Force, the Supply Adequacy Working Group, the Reliability Working Group, and the Market Subcommittee, and also provided updates to interested parties on an ad hoc basis. Exhibit Nos. IPL-7 and IPL-8 provide a snapshot of some of IPL's efforts toward stakeholder outreach.

It was not until January 5, 2016, however, that MISO made a presentation to stakeholders, to kick-off a stakeholder process on batteries. Unfortunately, no progress has been made to date to remedy the critical issues IPL and MISO identified. Throughout the discussions between MISO and IPL over the past two and a half years, little was changed to accommodate the device's participation in MISO. However, a great deal of knowledge was gained, which has shaped the proposal included in this filing.

At this time, the HSS BESS is the only grid-scale Lithium ion battery in the MISO footprint. It is in service and providing automatic Frequency Control benefits.

Q. Why does IPL believe it necessary to file a complaint at this time?

A. Even after more than two and half years of diligent efforts to pave a path for batteries within the MISO footprint, there is no clear path to enable the HSS BESS to operate as designed and be compensated for services rendered. This lack of appropriate path for Lithium ion batteries is a very material barrier to attracting other Lithium ion batteries to the footprint. IPL and MISO together explored whether the HSS BESS could participate in the Regulation market as an SER, a category limited to the provision of Regulating Service based on the technological characteristics of a flywheel. IPL also examined whether the HSS BESS could participate as Generation, Demand Response Type-1, Demand Response Type-II, Behind-the Meter Generation, or Use-Limited Resource. However, as MISO itself recognized in its May 16, 2016 Comments in Docket No. AD16-20,

> this list is subject to two important caveats. First, when MISO originally developed the non-SER resource categories, MISO did not specifically consider whether such categories could accommodate the unique features of various storage technologies. Second, as previously mentioned, the SER category was developed specifically for short-term storage, and its limitation to Regulating Service may not be appropriate for other forms of battery storage technology that have the capability to provide more than just Regulating Service. Consequently, MISO's operational system, software and procedures for these resource categories may not yet suitably address any unique operating characteristics of certain non-short-term storage resources.

Stated simply, the MISO Tariff does not provide a viable path for participation in the markets by resources such as the HSS BESS. MISO has made no changes to the Tariff, business practices, or processes to accommodate the IPL HSS BESS to allow it to operate as designed and provide efficient benefits to the grid. The HSS BESS was placed into commercial service on May 20, 2016. It is physically interconnected at 138 kV, but all injection and withdrawal is accounted for at the IPL load node. The asset has been removed from the MISO Commercial Model with MISO's knowledge and agreement, and is not participating in the MISO market as there is no appropriate means to do so without material harm to the device. Without changes made to the MISO Tariff and business practices to conform to the battery's operating characteristics and the changes needed to provide a reasonable economic outcome when providing service, the battery must remain administratively behind-the-meter. No resource should be required to provide service without a reasonable assumption that it will be paid appropriately for services rendered and that the RTO dispatch scenario is just and reasonable for the benefits the technology provides.

IV. USE OF THE HSS BESS TO PROVIDE PFR

Q. Describe the difference between PFR and Secondary Frequency Control or Regulating Reserve.

A. As stated earlier in this testimony, "FCS" refers to a continuum of four reliability services designed to manage frequency within the bounds of NERC standards to maintain a stable and reliable grid (*see* Exhibit No. IPL-2). The Commission has defined PFR "as a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over." *See Third-Party Provision of Primary Frequency Response*, 153 FERC ¶ 61,220 at PP 14 and 47 (2015).

In contrast, Secondary Frequency Control or Regulating Reserve is a means to assist Balancing Authorities in management of Area Control Error ("ACE") which is a measure of the instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of frequency bias, frequency deviation and correction for meter error. In contrast to PFR, which is an automatic response, Regulating Reserves are centrally dispatched by MISO. For all practical purposes, and in conformance with NERC standards and guidelines, resources providing PFR are also automatically providing all services in the FCS continuum automatically. NERC definitions recognize that services in the continuum may be automatic, dispatched and/or manually addressed. Generators with Governors and the HSS BESS merely read and respond to deviations in MISO system frequency and react regardless of cause or service definition. For this reason and to differentiate automatic service from dispatched service, I will group all automatic reaction into the term "PFR."

Q. What are the factors contributing to the decline in PFR?

A. In 2010, NERC began surveys and studies in an effort to understand the steady decline in PFR, particularly in the Eastern Interconnection. Several NERC reports described below highlight the results of this multi-year NERC effort, including their recommendations for State regulators and their jurisdictional utilities to include provision of essential reliability services in their Integrated Resource Plans. As documented in the DOE/National Energy Technology Report "Frequency Instability Problems in North American Interconnections" published May 1, 2011 and attached hereto as Exhibit No. IPL-10, "[o]ver the past decade, NERC has observed an increase in frequency stability problems. For example, *frequency response* in the Eastern Interconnection has deteriorated significantly over this period, so that progressively smaller power disturbances are able to induce significant frequency deviations." The report notes several causes of this that have been proposed, including changes in:

- An interconnection's moment of inertia: Power systems with multiple smaller turbine generators on-line (i.e., a primarily distributed generation system) have less rotational inertia than systems with fewer but larger turbine generators (i.e., a more centralized generation system), giving the more distributed system less kinetic energy immediately available to mitigate frequency changes. Furthermore, as more non-rotating (photovoltaic, fuel cell) and slowly rotating (wind) generators come on line, the kinetic energy per unit of generating capacity available to the overall power system to stabilize frequency decreases.
- Load types: Some end-use devices, such as electric motors, contribute to frequency stability because they use more power at higher frequencies and less

power at lower frequencies, thereby helping demand adjust to meet supply. As the load in North America changes, with less industrial consumption and more commercial and residential consumption, it includes more electronics and variable-speed drives that do not demonstrate the same beneficial frequency-power relationship as inductive motors.

- <u>Generation control practices</u>: Deregulation and competition in the generation industry have provided operators with incentives to operate plants at peak local efficiency (versus what is optimal for the overall power system) resulting in changes in generation control practices. Some operating practices can result in a lowering of the available range of governor control of on-line generators. This reduces the available level of [PFR], the ability of the system to react within a few seconds to stabilize system frequency.
- <u>Types of reserves and their availability</u>: Deregulation and competition also have provided control area operators with incentives to keep generation reserves at a minimum. To reduce costs, some operators have organized into reserve sharing groups (RSGs) that collectively meet their reserve requirements, resulting in lower levels of reserves available to respond to frequency disturbances.
- <u>Frequency control (monitoring and regulating) practices</u>: Controlling frequency requires primary frequency control using governors and Energy Storage Devices; secondary frequency control primarily consisting of automatic generation control (AGC) centrally dispatched as through a market to reduce area control error (ACE) to within acceptable limits; and tertiary controls bring available generators on-line over a period of minutes to hours to re-stabilize the frequency at the

nominal level. The need for devices to efficiently provide the essential reliability services of frequency and voltage control is critical with the increase of renewable and gas-fired generation resources replacing coal resources if reliability is to be maintained.

Q. Describe how Frequency Control is performed by MISO

A. The Regulation Reserve market in MISO is for the provision of Secondary Frequency Control. The market is a tool to assist MISO in management of ACE. The standard that prescribes the required performance for ACE is BAL-001-2 Real Power Balancing Control Performance. While the standard's stated purpose is to control Interconnection frequency within defined limits, this standard requires the Balancing Authority to operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit ("BAAL") for more than 30 consecutive clock-minutes. Performance to the standard is measured averaged over an hour. Using the market for Regulating Reserve provides the RTO with a means to manage the imbalance between load and generation as it deviates from scheduled, but does not provide PFR.

PFR is governed by NERC Standard BAL-003-1.1. As the Balancing Authority under BAL-003-1.1, MISO has the responsibility for meeting the PFR standards. MISO owns no generation or other resources capable of providing PFR and currently has little to no authority to direct owners to provide their fair share. Section 9.6.2.1 of the MISO Generator Interconnection Agreement requires the speed governors (if installed) to be operated in automatic mode ***if they are capable of operation***. In a March 10, 2016 presentation before the Interconnection Process Task Force (Exhibit No. IPL-9), MISO stated it is currently meeting its PFR obligation "though legacy units and natural load response" and noted "[w]ith no economic benefit and no requirement, majority of new generation provides no frequency response."

Q. Does MISO compensate suppliers directly for PFR?

A. No. MISO does not compensate for provision of PFR.

Q. Please describe IPL's proposal as to how MISO should compensate suppliers of PFR.

A. IPL proposes that resources that provide automatic frequency control services along the continuum - PFR be paid consistent with payment for Secondary Frequency Response in the market. Our proposal is summarized as follows—IPL proposes that PFR be paid:

(1) In real-time the LMP multiplied by the amount of MWhs they inject in order to respond to under frequency situations;

(2) The LMP multiplied by the amount of MWhs they absorb in order to respond to frequency situations; and

(3) An initial mileage factor of 2.9 times the amounts in (1) and (2) for faster resources to account for the benefits of faster performance.

IPL also proposes to adopt the entire structure MISO uses in day-ahead and real-time for the Secondary Frequency control dispatched Regulation market for devices providing such services automatically (not dispatched). This provides a market solution to an automatically provided service.

As with any MISO market product, IPL would expect that experience, technological changes, and regulatory initiatives (including, but not limited to, FERC rulemakings) will require modifications to this approach. Nevertheless, IPL's proposal represents a reasonable means to compensate resources for the actual PFR they contribute to maintain MISO grid stability in an expedient manner. Because the HSS BESS cannot participate in the dispatched market at this time, the only service it will provide is PFR. Using the ("LMP") would be consistent with the real-time payment for a deployed flywheel providing Regulating Reserve as an SER (*see* Exhibit No. IPL-11).

Q. Why does IPL recommend pricing PFR service at the LMP?

A. IPL believes this to be a conservative, initial approach to introduce the unbundled pricing of the PFR service. For other Ancillary Services, MISO pays a capacity or opportunity cost for keeping the resource available if needed. MISO then pays the LMP if the resource is subsequently deployed.

In its proposal, IPL is not including any availability payment for the first six months as some time will be needed to adapt the settlement structure to automatic provision of frequency control. For the first six months when the resource responds automatically to mitigate over or under frequency there would be a payment at LMP multiplied by the benefits factor, but no payment for availability. I note that MISO currently pays the LMP to Demand Response Type-II resources that reduce load on the grid. Exhibit No. IPL-12 is a MISO-produced Settlements Presentation that explains this payment logic. The settlement of DRR Type II and the payment for reduction of load is explained in MISO's Market Settlements Overview beginning on slide 68. While the settlements presentation may look confusing, the settlement for Type II when reducing load on the grid is consistent with the simple explanation for Emergency Demand Response ("EDR") on slide 70.

Q. Why does IPL recommend utilization of an initial 2.9 mileage factor for faster resources?

A. Frequency Control is time-sensitive. In response to a sudden power imbalance, the faster the PFR can be deployed the sooner the nadir of the event will be arrested. Fewer MWs of service from slower resources will be needed as a result.

Absent a resource-specific benefits or performance factor for fast resources, there would be no difference in the payment for units with the faster response time and slower performance. A performance factor is consistent with the pay for performance requirement the Commission instituted for Regulation Reserves in Order No. 755. The 2.9 factor proposed by IPL, as an initial approach only, is the same factor the Commission determined to be just and reasonable for resources that respond to the fast Regulation (REG D) signal in PJM. Accordingly, IPL recommends that for an interim period only MISO would apply the 2.9 factor to faster resources until MISO can develop an appropriate benefits factor for its own footprint. Each resource in the fast group will have its own benefits factor based on its own performance speed and availability.

Q. Why should providers of PFR be compensated both for energy injections as well as energy withdrawals used to maintain system frequency?

A. In both cases -- injecting energy to mitigate under-frequency or withdrawing energy to alleviate over-frequency -- the unit is providing PFR, an essential reliability service. To pay only for injections would create the wrong incentive for units only to provide half of what is needed for PFR. Moreover, paying for positive PFR and charging for withdrawals to mitigate high frequency inappropriately reduces the compensation that should be paid for services provided and the benefits to the grid. While generators with governors can only inject, they provide frequency control service by increasing or decreasing the quantity injected. Demand response provides frequency control by reducing load. Lithium ion batteries behave with the same benefits of both generators and demand response in the provision of frequency control. Generators and Demand Response are compensated for their respective provision of benefits. The same considerations should be accorded batteries providing PFR.

Q. Should there be a penalty for non-performance?

A. IPL would agree that there should be a penalty for non-performance. Once a resource has committed to provide a certain MW quantity of PFR and has been certified as capable, the resource should be penalized if it fails to respond appropriately. IPL recommends using the same penalty structure that exists for the dispatched Regulation Service with modifications for automatic service provision.

Q. How does IPL propose to treat withdrawals, necessary to maintain the battery's state of charge?

A. IPL would propose that withdrawals used to manage the SOC for the HSS BESS or any other battery be separately metered and charged the applicable LMP as is all company use or station power in the MISO footprint. SOC and Ancillary load are separately metered and accounted for the HSS BESS.

V. REFORMS NECESSARY FOR BATTERIES TO PROVIDE REGULATING RESERVE IN MISO

Q. What prevents the HSS BESS from participation in the MISO market for Regulation Service?

A. Regulating Service is the only product currently permitted for SERs to participate in the MISO markets. Accordingly, IPL and MISO together explored the feasibility of utilizing this resource type, business rules, and dispatch for providing this service by the HSS BESS. IPL realized; however, that it was operationally and economically infeasible for the HSS BESS to provide Regulating Service under the current MISO Tariff and market rules for SERs. The SER defined category was specifically designed for flywheel technology and, for flywheels, appears to be designed appropriately. The dispatch scenarios and business rules for SERs if used for the HSS BESS would significantly interfere with optimal SOC management, diminish the life of the battery cells materially, and will prevent the device from providing its unique benefits to IPL customers and the grid including speed to solution.

Q. How would the manner in which MISO currently dispatches SERs degrade the useful life of the HSS BESS?

A. Because the SER resource type was designed specifically for flywheel technology, MISO would for example dispatch the HSS BESS at half its capacity continuously across an hour and then send it a negative signal in the next hour to charge continuously over the hour. The design includes a requirement that the resource, through Inter-Control Center Communications Protocol ("ICCP"), provide MISO with factors to determine its SOC, so that the flywheel is never dispatched at a setpoint that is beyond its capability given the

SOC. The HSS BESS manages its own SOC so that it is continuously available and can continuously provide service. SOC management for the 244 nodes in the HSS BESS occurs simultaneously with provision of service. It does not require a "rest" period after discharging to recharge. It is designed to react to frequency deviations nearly instantaneously and continue injection or withdraw so long as the event lasts. Using the dispatch designed for flywheels ignores the requisite operating characteristics and benefits of Lithium ion batteries, and will cause the HSS BESS to be less available and less beneficial in the provision of PRF.

While this is appropriate for flywheel technology, it is harmful to Lithium ion technology. The life expectancy of a battery cell is highly dependent upon appropriate operation to maintain the life of the cells. As designed, the HSS BESS must allow its operating software to optimize its SOC so that it is continuously available in accordance with the known characteristics of Lithium ion batteries. For Lithium ion technology, life expectancy is measured in the number of expected cycles in the life of the battery. A cycle is the process of charging to capacity and then totally or nearly-totally discharging. To maximize the life of a Lithium ion battery one should continuously maintain a charge level of 50-60% rather than allowing the battery to fully deplete before recharging. By continuously maintaining a charge at for example 60% rather than running the battery down and then recharging will prolong the battery's life. The dispatch scenario for SERs essentially causes the anticipated number of life cycles of the cells to be consumed in a much shorter time period than if the battery is operated properly. The HSS BESS cell life is anticipated to be approximately 10 years with proper operation. If dispatched under the SER resource procedures, IPL would expect the cell life to be only three years. To replace 97,600 cells in 3 years rather than the expected 10 years would cause a material financial hardship. The SER dispatch scenario also ignores and handicaps the actual benefits of a device that can respond at its full capacity in about 1 second and prevents it from being continuously charged and continuously available.

Q. How should MISO remedy the dispatch issue?

A. The manner in which the devices are dispatched when participating in any of the Ancillary Service markets should, at least outside of emergency conditions, conform to the operating characteristics of the device and cause them no harm. They should not be confined to providing energy over the course of an hour, then be forced to charge and be unavailable in the next hour. Nor should they be dispatched without the ability to manage the SOC for optimal performance. The HSS BESS Advancion® software can manage the response of the battery in every dispatch interval both injecting and withdrawing in one second while meeting the dispatch level represented in the offer curve. To operate them in any other manner can damage them and will reduce or perhaps even eliminate the benefits to the grid that they can provide. Lithium ion batteries are not generators as they do not generate anything. They store energy for future use and can be designed to meet many different reliability and other needs. They must be permitted to operate according to their own characteristics and not be forced to operate as if they were a generator or a flywheel. Requiring them to perform according to the characteristics of a generator or flywheel both harms the life of the device and materially diminishes the benefits of their speed and efficiency.

Q. What concerns does IPL have with the manner in which MISO would compensate the battery for Regulating Reserve?

A. IPL's concerns with the current MISO approach to compensating batteries registered as SERs that provide Regulating Reserve parallel the recommendations for PFR. First, the resource should be paid and not charged for providing downward regulation when it is withdrawing energy to mitigate oversupply. Second, the Commission should, until a MISO-specific factor can be implemented, require MISO to utilize the 2.9 performance factor for resources that respond faster for an interim period.

Development of a performance factor appropriate for the MISO footprint can leverage some of the work done in PJM for REG D service, as well as similar work performed for the ERCOT footprint. For REG D service in PJM, that factor is 2.9 as opposed to the maximum allowed for traditional resources of 1.0. Conceptually that factor accounts for the speed to respond to the 5 minute dispatch signal. Accordingly, the REG D benefits factor or mileage rate compensates somewhat for the vastly more expedient response. It does not, however, put batteries on comparable footing with generators relative to compensation due to the cost applied when withdrawing from the grid. Batteries responding to either positive or negative deviations in one second are actually providing more benefit on a MWh basis than traditional resources and therefore should be compensated for this versatility and efficiency.

Q. You indicated that MISO should be required to adopted PJM's mileage factor for Regulating Reserve. Why is this appropriate as an initial measure?

A. In their implementation of Order 755, PJM included a methodology for utilization of fast resources, they call "dynamic resources." Exhibit No. IPL-13 contains an excerpt from

PJM Manual 11. While the benefits factor for fast resources in MISO may ultimately be different from that implemented in PJM due to the resource mix differences as well as differences in dispatch and settlements software, using the 2.9 benefits factor is reasonable as a starting point.

Q. Didn't the Commission accept MISO's mileage proposal in its Order No. 755 Compliance Filing?

A. Yes. While MISO's implementation of FERC Order No. 755 was in compliance they did not consider fast resources such as batteries since none were is service at that time. The benefits factor is limited to 1.0 or equal to the upper limit allowed for traditional resources. This factor is equivalent to REG A in PJM. Given the resource mix in MISO when they implemented Order No. 755, this was sufficient. However, it is no longer just and reasonable since the HSS BESS is now in service. It is insufficient to attract batteries and other fast-moving resources to the footprint. Essentially there is no pay for performance at the level a battery can perform in MISO. This should be remedied. The Commission should order MISO to come forward with its own proposal for a benefits factor for fast-responding resources in six months, to be implemented within eighteen months.

VI. ADDITIONAL MISO REFORMS TO ENABLE BATTERIES TO PROVIDE ALL SERVICES THEY ARE CAPABLE OF PERFORMING

Q. Describe the services and grid benefits that can be provided by ancillary service devices.

A. As stated before in this affidavit, Lithium ion batteries can be designed to provide many Ancillary Services as well as those not categorized as Ancillary Services such as Ramp. In addition, they can also be specifically designed to replace peakers. For example, the HSS BESS can be providing PFR services; then, if needed, provide capacity over the four hours of the peak; and then return to providing PFR. Due to their ability to respond in one second as compared with the longer response times of various generator types, batteries can mitigate a variety of challenges in an expedient manner, and in doing so may reduce the possibility of an under frequency load shed or cascade event, particularly if there is a sufficient shortage of resources providing the needed services in the MISO footprint.

IPL believes that the MISO Tariff must be reformed to enable batteries as well as all resources, regardless of technology, to qualify for any of the products they are capable of providing. Lithium ion batteries as well as other traditional and stored energy technologies can do more than just Regulating Service. If MISO wants to maintain this terminology for a particular technology, such as a flywheel, it must utilize a new term for batteries that are not "generators." This term must recognize the fact that they store and subsequently deploy energy generated by other means.

Q. Does that conclude your testimony?

A. Yes.

VERIFICATION OF LIN FRANKS

Indianapolis Power & Light Company	)	
Complainant,	)	
v.	)	**Docket No. EL17-___-000**
Midcontinent Independent System Operator, Inc.	)	
Respondent.	)	

County of Marion	)
	)
State of Indiana	)

Lin Franks, being duly sworn, avers and states that she prepared or oversaw the preparation of the enclosed testimony and that the information contained therein is true and correct to the best of her knowledge and belief.

Lin Franks
Senior Strategist, RTO, FERC and
Compliance Initiatives
Indianapolis Power & Light Company

SUBSCRIBED AND SWORN BEFORE ME, this the 10th day of October, 2016.

Notary Public

My Commission Expires 4-11-2020

Exhibit No. IPL-1

Harding Street Station Battery Energy Storage System Components

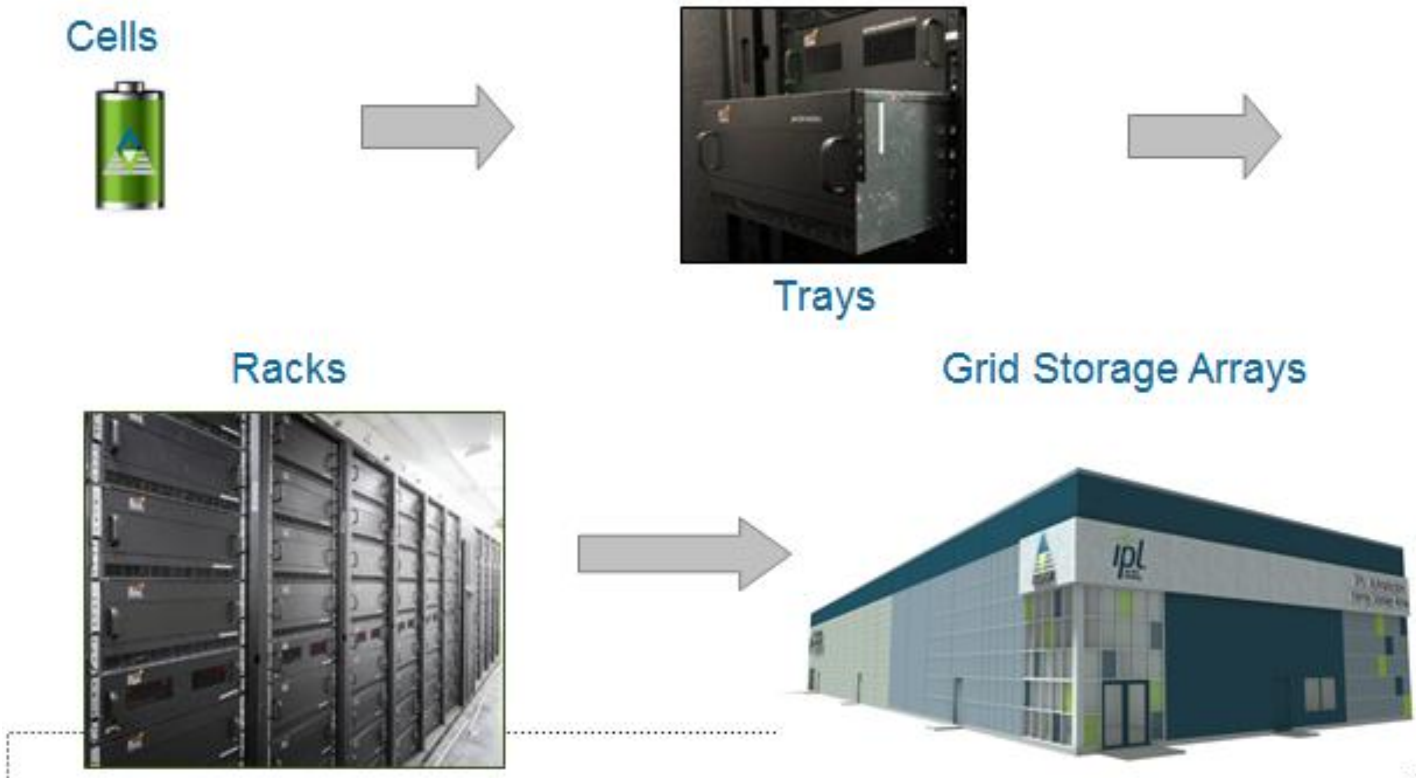
Cells
Trays
Racks
Grid Storage Arrays

Exhibit No. IPL-2

Frequency Control Time Continuum Table

Control	**Ancillary Service**	**Dispatched / Automatic**	**Purpose**	**How is it accomplished?**	**NERC STANDARD**
Primary Frequency Control	Primary Frequency Control or Primary Frequency Response	Automatic	To arrest in 10-60 seconds the degradation of frequency following an event such as a generator tripping or a weather related transmission outage.	All generators with active governors installed automatically or other resources capable of automatically responding react to deviations in system frequency by increasing or decreasing their output.	FRS-CPS1 BAL003-1
Secondary Frequency Control	Regulation, Spinning Reserves	Dispatched	To manage the difference between scheduled generation and load with actual. This is called Area Control Error (ACE is for a balancing area and includes a frequency deviation and frequency bias components).	Resources are dispatched by the Balancing Authority/RTO adjusting their output in an attempt to balance real time generation, and load, and scheduled interchange. Response required in up to 10 minutes in most RTOs	CPS1-CPS2-DCS-BAAL
Tertiary Frequency Control		Manual and Dispatched	To correct the imbalance created by the event.	Reliability Coordinator can redispatch on line generating resources, mandate load shed / curtailment and / or dispatch resources not already online. This process can take 10 minutes to hours depending upon the event.	BAAL-DCS
Time Control	Time Error Correction	Automatic	To regulate system frequency in a manner that keeps synchronous clocks running accurately.	RTOs set system frequency to a level that will elicit a response from generators with governors or other resources capable of automatically responding.	TEC

Exhibit No. IPL-3

Performance of the HSS BESS During a Sample of Hours on July 6, 2016

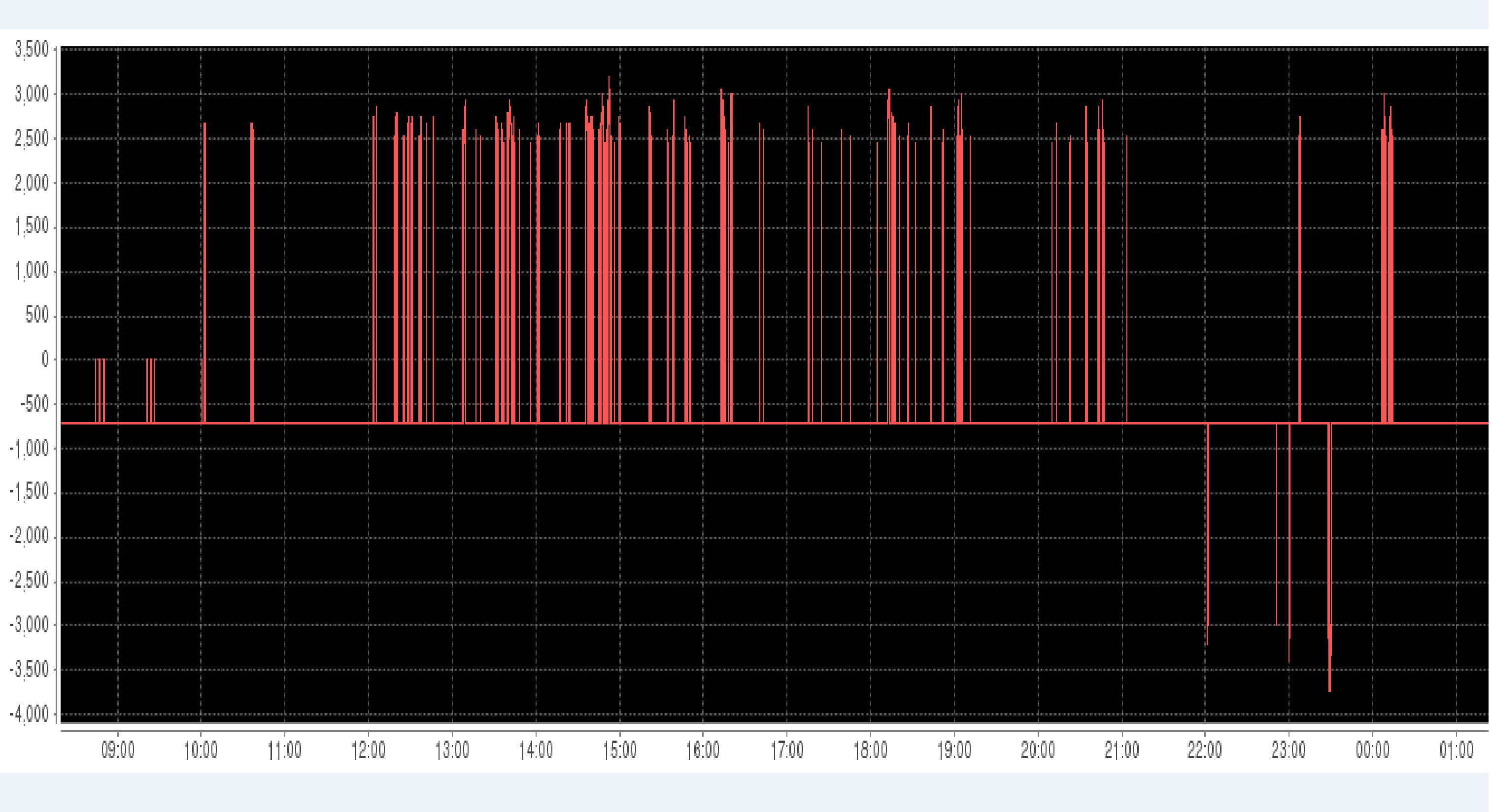
3,500
3,000
2,500
2,000
1,500
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Exhibit No. IPL-4

NERC Reliability Guideline - Primary Frequency Control

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Primary Frequency Control

Preamble

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC; the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) per their charters are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security Guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise and judgment of the industry. The objective of this reliability guideline is to distribute key best practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

Frequency Control

Much of the technical background on frequency response can be found in the 2012 Frequency Response Initiative Report (FRI). The FRI report provides a detailed explanation of many of the intricacies of frequency response and the reader is encouraged to review that document for a more thorough discussion of the subject.

To understand the role Primary Frequency Control plays in system reliability, it is important to understand different components of frequency response, and how individual components relate to each other. For the purpose of this guideline, the focus will be on Primary Frequency Control with Primary Frequency Response and Secondary Frequency Control also illustrated.

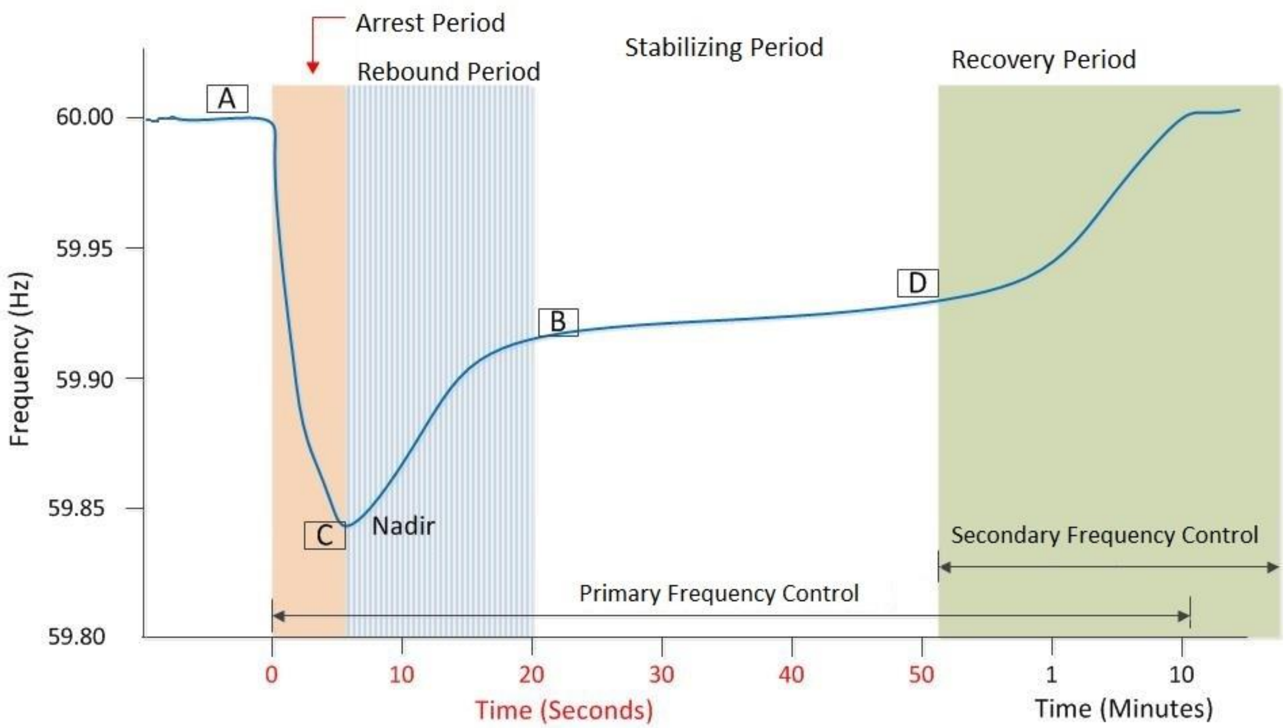
Definitions Used

- **Primary Frequency Response (PFR) (commonly referred to as Frequency Response)** – Actions from uncontrolled (natural) sources in response to changes in frequency: rotational inertia (H) response from resources and load response from frequency dependent loads (e.g. motors). In addition, it can come from Primary Frequency Control (as described below).
- **Primary Frequency Control** – A subset of Primary Frequency Response actions provided by prime mover governors in an interconnection to arrest and stabilize frequency in response to frequency deviations. Primary Frequency Control comes from local control systems.

- **Secondary Frequency Control** – Actions provided by an individual Balancing Authority to correct the resource-to-load imbalance that created the original frequency deviation that will restore both Scheduled Frequency and Primary Frequency Response. Secondary Frequency Control comes from either manual or automated dispatch from a centralized control system such as Automatic Generation Control (AGC).

Primary Frequency Control is essential for maintaining the reliability of the BES. For example, Planning Authorities' stability studies use models based on generator parameters, including governors' frequency control parameters, reported by Generator Owners. These same models are also used to evaluate Under Frequency Load Shedding (UFLS) needs and assess the frequency response of the system during restoration activities. Actual performance differing from that expected using reported values, whether within recommended deadband and droop settings or not, could detrimentally affect system reliability.

Point A is defined as the predisturbance frequency; Point C or Nadir is the maximum deviation due to loss of resource; Point B is defined as the stabilizing frequency and; Point D is the time the contingent Balancing Authority begins the recovery from the loss of resource.



Note: Some Secondary Frequency Control may begin earlier or later than illustrated. Also, some Primary Frequency Control may end earlier than illustrated due to governor deadband.

Purpose

This Reliability Guideline provides a strategy for Primary Frequency Control during frequency deviation events, as well as information to the industry recommending governor deadband and droop settings that will potentially enable resources to provide better frequency response to the BES. For the ERCOT Interconnection, governor deadband and droop settings are requirements set forth in NERC Regional Standard (BAL-001-TRE-1). Similarly, WECC has a Regional Criterion stating that if generating resources have governors, droop settings should be within a three to five percent range.

This guideline is intended to assist Balancing Authorities, Generator Operators, and Generator Owners in providing more effective frequency response during major grid events, and to address techniques of measuring frequency response at a resource level. It is offered as information to other Functional Model entities.

This Reliability Guideline outlines a coordinated operations strategy for resources to stabilize system frequency when frequency deviates due to a grid event. It is designed to keep frequency within allowable limits while maintaining acceptable frequency control. This Reliability Guideline is not applicable to resources that are connected to asynchronous loads or systems that are not normally a part of one of the Interconnections.

This Guideline does not create binding norms, does not establish mandatory Reliability Standards and does not create parameters by which compliance with Reliability Standards are monitored or enforced. In addition, this Reliability Guideline is not intended to take precedence over any Regional procedure.

Guideline Details

Primary Frequency Control is the first stage of overall frequency control and is the response of resources to arrest the locally measured or sensed changes in frequency. The controlled response of Primary Frequency Control is automatic, is not driven by any centralized system, and begins within cycles of the frequency change rather than minutes.

By having Primary Frequency Control, the impact of events on the BES can be minimized and better frequency control obtained. If frequency on the BES is not within the normal operating range, Primary Frequency Control should be sufficient to assist in arresting and stabilizing of abnormal frequency.

In order to provide Primary Frequency Control, it is recommended that all resources connected to an Interconnection be equipped with a working governor or equivalent frequency control device.

The primary focus of this Guideline is prime mover governors. Other forms of resources providing frequency response should have similar response characteristics described herein for governors.

Primary Frequency Coordination

In order to provide sustained primary frequency response, it is essential that the prime mover governor, plant controls and remote plant controls are coordinated. The lack of coordination between governor and load control systems will reduce primary frequency response, increase generator movement, and could increase grid instability.

Modern and legacy power plants are equipped with a wide variety of governor and plant control systems. In general, all prime movers will utilize some form of speed governor. Typically, this is a core part of the machines over speed protection as well as the foundation for the speed droop governor.

Modern systems generally incorporate a form of plant or unit load control. These Load Control Systems can be locally or remotely controlled and can be applied within the turbine control panel, the plant control panel or even remotely from a central dispatch center. In each of these control systems, the primary frequency control of the turbine governor must be taken into account to achieve sustained primary frequency response. Without coordination of the turbine governor's response to all speed changes, these additional control systems will react to the primary frequency response as a control error and quickly reverse the action of the governor. See Figure 1 below.

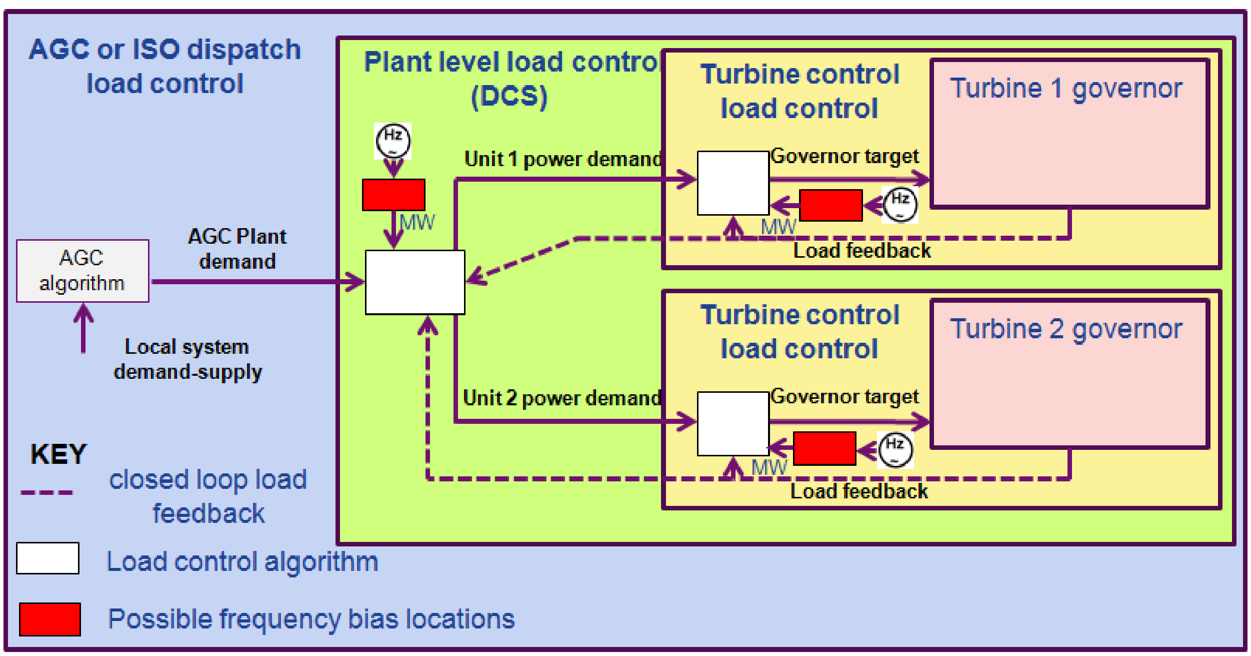


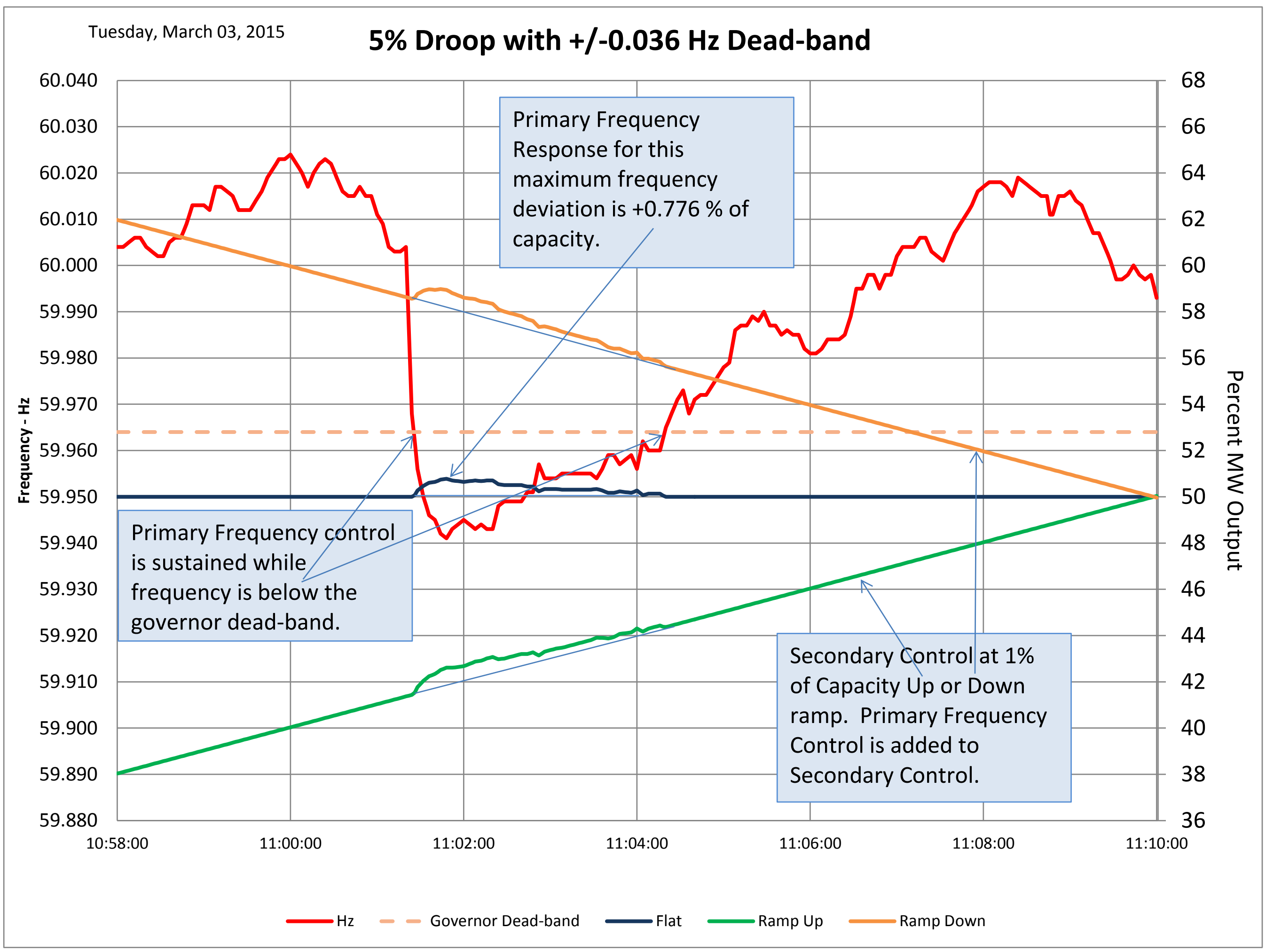
Figure 1: Typical High Level System

Closed loop load control will normally exist in at least one and possibly both load control loops. Frequency bias should be applied at the highest level of closed loop load control.

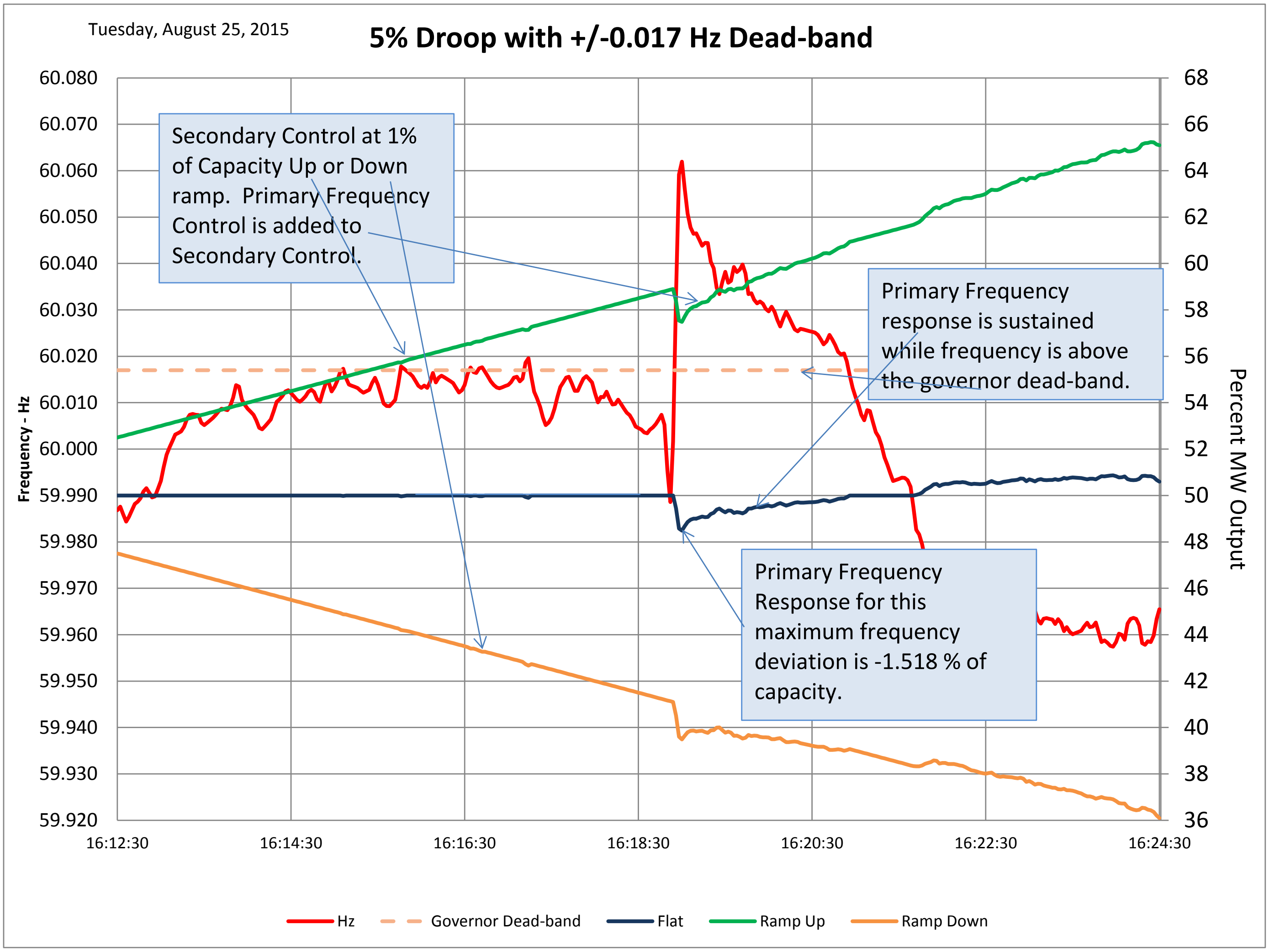
In order to understand the problem, it is necessary to study all layers of the load control system and verify that none of the layers undo the underlying governor response. This can generally be accomplished in several ways, including the following:

1. Use of a frequency bias in the plant level load controller would allow it to adjust individual load target in harmony with the governor response.
2. Use of a frequency bias in the turbine level load controls in conjunction with open loop load control at the plant level would allow the turbine control panel to adjust its internal load control target in harmony with the governor response.

   In both cases (1) and (2) the plant level load controls can adjust targets in response to external input, (e.g. a revised AGC target). Coordination of plant, turbine and governor controls dead bands and droop settings must also be coordinated as a system so as not to exceed the maximum recommended settings.
3. Operation of the unit in pure governor control with manual adjustments to the speed governor target such as analog or mechanical control systems and some early digital controllers typically include units that do not operate in any form of MW target control.



Example of Properly Coordinated Primary Frequency Control while ramping up or down via local or remote control or while operating at a fixed output.



Example of Properly Coordinated Primary Frequency Control while ramping up or down via local or remote control or while operating at a fixed output in the graph below - High Frequency excursion with a lower deadband

Governor Deadband and Droop

This guideline proposes maximum governor settings to achieve desired frequency response for each of the following Interconnections, subject to legitimate technical, operational, or regulatory considerations that would prevent governors from achieving the maximum governor settings. Although there are recommended governor deadband maximums for three of the Interconnections (36 mHz), it should be noted that deadbands of 17 mHz have been successfully implemented and efforts lowering deadbands to that level is encouraged. Similarly, deadbands are recommended to be implemented without a step to the droop curve, i.e. once outside the deadband the change in output starts from zero and then proportionally increases with the input. A more detailed discussion of the two methods can be found in Appendix B of "Dynamic Models for Turbine-Governors in Power System Studies" published by the IEEE PES in January 2013.

The recommended settings for each Interconnection are as follows:

Eastern Interconnection

A. Governor Settings – The following are recommended settings for governors or equivalent frequency control devices, subject to legitimate technical, operational, or regulatory considerations that would prevent governors from achieving the maximum governor settings.

1. **Deadband** –The deadband setting should not exceed +/- 36 millihertz (59.964 Hz to 60.036 Hz)
2. **Droop –** The droop setting should not exceed the following for each respective type of generator.

Generator Type	Max. Droop Setting %
Combined Cycle Facility[1]	
• Combustion Turbine	**4%**
• Steam Turbine	**5%**
Combustion Turbines[2]	**5%**
All Others	**5%**

[1] The maximum expected droop performance for the entire combined cycle facility is 6%. The combustion turbines should not exceed 4%.
[2] Many combustion turbines have a 4% droop setting which is within the maximum recommended setting.

ERCOT Interconnection

A. Governor Settings – The following are the BAL-001-TRE-1 requirements for deadband and droop settings.

1. **Deadband** –The deadband setting should not exceed the following :

Generator Type	Max. Deadband
Steam and Hydro Turbines with Mechanical Governors	**+/- 0.034 Hz**
All Other Generating Units/Generating Facilities	**+/- 0.017 Hz**

2. **Droop –** The droop settings should not exceed the following for each respective type of generator:

Generator Type	Max. Droop Setting %
Hydro	**5%**
Nuclear	**5%**
Coal and Lignite	**5%**
Combustion Turbine (Simple Cycle and Single-Shaft Combined Cycle)	**5%**
Combustion Turbine (Combined Cycle)	**4%**
Steam Turbine (Simple Cycle)	**5%**
Steam Turbine (Combined Cycle)	**5%**
Diesel	**5%**
Wind Powered Generator	**5%**
DC Tie Providing Ancillary Services	**5%**
Renewable (Non-Hydro)	**5%**

Western Interconnection

A. Governor Settings – The following are recommended settings for governors or equivalent frequency control devices, subject to legitimate technical, operational, or regulatory considerations that would prevent governors from achieving the maximum governor settings.

1. **Deadband** –The deadband setting should not exceed +/- 36 millihertz (59.964 Hz to 60.036 Hz)
2. **Droop –** The droop settings should not be less than 3% or greater than 5% and should not exceed the following for each respective type of generator:

Generator Type	Max. Droop Setting %
Combined Cycle Facility[3] • Combustion Turbine • Steam Turbine	**4%** **5%**
Combustion Turbines[4]	**5%**
All Others	**5%**

[3] The maximum expected droop performance for the entire combined cycle facility is 6%. The combustion turbines should not exceed 4%.
[4] Many combustion turbines have a 4% droop setting which is within the maximum recommended setting.

Quebec Interconnection

A. **Governor Settings –** The following are the recommended settings for governor frequency response:

1. **Deadband** – There should be no deadband on generators within the Quebec Interconnection.
2. **Droop –** The droop settings should be five percent for all types of generation within the Quebec Interconnection.

Performance Assessment

Some Balancing Authorities have developed methods for determining if prime mover governors are working properly by reviewing Energy Management System scan rate data (e.g., every four seconds) stored in their data historians (e.g., PI). Verification of the proper functioning of prime mover governors within a Balancing Authority can be time consuming and requires subject matter expertise. Balancing Authorities are strongly encouraged to evaluate the governor response being provided within their Balancing Authority Area. To assist in this effort, methods used successfully by some Balancing Authorities to address this task are presented below and may be used as a starting point for similar efforts of other Balancing Authorities.

The ERCOT Interconnection is a single Balancing Authority interconnection and has developed metrics to evaluate governor response performance. These metrics are included in the Regional Reliability Standard BAL-001-TRE-1, Attachment 2 "Primary Frequency Response Reference Document." The attachment provides performance metric calculations for Initial Primary Frequency Response (section II), Sustained Primary Frequency Response (section III), and Limits on Calculation of Primary Frequency Response Performance (section IV). The first metric, described in section II, uses a fixed time interval to determine initial governor response to a frequency event. A second metric, described in section III, also uses a fixed time interval to determine if frequency response is being sustained. High scores on both metrics indicate that frequency response is being sustained, as desired. Low scores on both can indicate that frequency response is not being provided. Problems with outer loop control causing frequency response to be withdrawn (i.e., squelched response) can be indicated by a relatively high score in the first metric and a lower score in the second metric.

Several NPCC Balancing Authorities within the NPCC Region have used a graphical approach to determining if generator governor response is being sustained. Two plots of generator output and frequency are reviewed in the evaluation of a generator's response, along with some supplemental data. The first plot (starting five minutes before the decline in frequency and ending 15 minutes after the decline in frequency) is used to determine if other factors such as unit ramping or AGC control are occurring, which may invalidate the utility of the sample (it is not a "controlled" experiment). The second plot (starting one minute before the decline in frequency and ending two minutes after the decline in frequency) is used to determine the type of response observed and to calculate an observed droop if the response is being sustained. The analysis performed is a 3-step process: sample validation, response type classification, and droop verification. The process is explained further in Appendix A. A fixed time window is not used in the response type classification and droop verification, because Eastern Interconnection frequency deviations often persist for longer than one minute, and frequency response should be sustained until the frequency returns to a value within the governor deadband.

Historical Reference

The retired 2004 NERC Operating Policy 1, Generation Control and Performance, section C, stated:

1. Governor installation – Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates.
2. Governors free to respond – Governors should be allowed to respond to system frequency deviation unless there is a temporary operating problem.
3. Governor droop – All turbine-generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, at a minimum, be fully responsive to frequency deviations exceeding ±0.036 Hz (±36 millihertz).
4. Governor limits – Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.

Cited Documents

1. BAL-001-TRE-1
2. Frequency Response Initiative Report 2012
3. NERC Alert A-2015-02-05-01
4. IEEE PES Appendix B of "Dynamic Models for Turbine-Governors in Power System Studies"

Revision History:

Date	Version Number	Reason/Comments
12/15/2015	1.0	Initial Version – *Reliability Guideline: Primary Frequency Response*

Appendix A

Sample Validation, Response Type Classification, and Droop Verification

Sample Validation

There are several factors to be considered in determining if a particular declining frequency event can provide useful information about the frequency response of a particular generator. Any one of the following factors can reduce the confidence in or totally invalidate the performance sample.

- Improper data storage tolerances in the data historian
- Oscillatory generator output due to plant control tuning problems
- Generator is off line, ramping up or down due to dispatch instructions, or on AGC
- Output is at or near the generator high limit at the time of the frequency event
- Inaccuracy in the measurement of plant output
- Noisy telemetry of the output of the generator
- Actual high limit's sensitivity to ambient temperature versus a high limit provided based on forecasted temperature
- Higher levels of output is provided by equipment that is not frequency responsive (e.g., duct burners, steam injection)

Response Type Classification

Once a sample for a declining frequency event has been validated, an attempt is made to classify a sample as one of the following types based on a review of the plots of actual generation and frequency.

- Sustained - output increases after the frequency deviates below the governor deadband, with frequency response that is proportional to the ongoing frequency deviation beyond the governor deadband continuing until the frequency returns to be within the governor deadband.
- Squelched - output increases after the frequency deviates below the frequency deadband, but it decreases significantly in the direction of the output level that existed prior to the decline in frequency even though the frequency continues to be below the governor deadband.
- No Response - the output is essentially unchanged when the frequency deviates below the governor deadband.
- Negative Response - the output declines as the frequency declines, possibly due to thermal limitations or improper configuration of plant controls.

Individual samples are compared to determine an overall response type classification, and repeatability among samples is a key factor in this determination. A high degree of confidence in the overall classification can be developed when five to ten samples exhibit the same response type. However, an overall assessment of squelched response may require a greater number of samples, as the relative values of actual generation versus the desired dispatch level and its surrounding megawatt control deadband can result in a mixture of response types among samples. For example, out of 20 samples, six may appear to be sustained, six squelched, six no response, and two negative response.

Droop Verification

For generators classified as having sustained response, the droop and deadband settings can be verified. An expected output change for a declining frequency event can be computed based on generator size, droop setting, governor deadband, and the frequency observed when it is relatively stable during the event. This computed expected value can be compared with the actual observed change in output. Greater confidence in this verification can be achieved if the mean and median of about ten events are used in the comparison.

If the droop and deadband settings are not known, but there are about ten samples of sustained response, trial droop and deadband values can be used to estimate an effective droop/deadband pair by matching the mean and median of the observations with those expected for candidate droop/deadband pairs.

The empirical/effective droop settings can vary substantially for some conventional thermal generators based on load levels. For some generators, it may be desirable to compute different effective droop values for different output ranges. The droop rating is applicable to the entire operating range, while droop performance can vary depending on the initial load (and its corresponding governor valve position) when a frequency event occurs.

Exhibit No. IPL-5

February 18, 2014 Informational Report of MISO
(Docket No. ER12-1664-000)

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February 18, 2014

VIA E-FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***Midcontinent Independent System Operator, Inc.* – Informational Report**
Docket No. ER12-1664

Dear Secretary Bose:

Pursuant to the direction of the Federal Energy Regulatory Commission ("Commission") in its *Order on Compliance Filing* issued in Docket No. ER12-1664,[1] the Midcontinent Independent System Operator ("MISO") hereby submits the attached Informational Report that provides the status of MISO's regulation market since implementation of the performance-based revisions as required by Order No. 755.[2] MISO notes that pursuant to the Commission's order, the Commission does not intend to issue a public notice, accept comments, or issue an order on this report.[3]

I. BACKGROUND

On April 30, 2012, MISO filed proposed revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff")[4] to establish a revised compensation methodology for the provision of regulation service in compliance with Order No. 755. On September 20, 2012, the Commission issued its *Order on Compliance* and found MISO's proposed revisions generally compliant with Order No. 755. Accordingly, the Commission conditionally accepted the proposed revisions, subject to a further compliance filing, effective December 17, 2012.[5] The Commission also directed MISO to provide a report on certain issues 14 months after implementation of the revisions. Accordingly, MISO submits the instant Informational Report.

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1 *Midwest Indep. Sys. Transmn. Operator, Inc.*, 140 FERC ¶ 61,224 (2012) ("*Order on Compliance*").

2 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 (2012).

3 *Order on Compliance* at note 45.

4 Capitalized terms not otherwise defined herein have the meanings ascribed thereto in Section 1 of the Tariff.

5 MISO submitted a compliance filing to comply with the *Order on Compliance* on October 22, 2012; the Commission accepted the compliance filing via Letter Order on January 25, 2013.

II. <u>INFORMATIONAL REPORT</u>

MISO provides the attached Informational Report (at Attachment A) to provide the Commission with a general report on the health of MISO's regulation market and the overall impact of implementing the Regulating Mileage Market Clearing Price ("MCP"). The Commission's *Order on Compliance*, directed MISO to include the following specific updates in the Informational Report:

a) Information describing the extent to which its deployment assumption reflects actual deployment, and what effect that has had on the need to credit and charge back market participants for their actual provision of regulation service in response to real-time dispatch;[6]

b) An update on the effect the 1:1 deployment ratio (between Regulating Mileage and Regulating Reserve) has had on the efficient clearing and equitable settlement of the frequency regulation market;[7] and

c) Additional information about the factors affecting the 70 percent tolerance band for resource response and whether the tolerance band should continue to include a factor that reflects resources' inability to accurately follow Setpoint Instructions.[8]

With regard to items (a) and (b), on November 19, 2012, following the Commission-directed compliance filing in the instant docket, MISO submitted Tariff amendments to address both the deployment assumptions and the deployment ratio. Specifically, MISO proposed to establish a monthly regulation deployment factor that is based on the ratio between the Regulating Mileage Target and the Regulating Reserve Dispatch Target, using actual regulation deployment data. As a result, the Regulating Mileage cost considered in the market clearing process accounts for the average system-wide impact on the relationship between Regulating Mileage and Regulating Reserve for the previous month. The Commission agreed that an adjustable deployment ratio can help alleviate the potential uplift cost issue on a system-wide basis and accepted MISO's proposal via Letter Order on January 25, 2013, and the Tariff changes were made effective on February 1, 2013. Since that time, MISO has posted the ratio used in the market clearing each month. Since February 2013, the ratio has been between 0.55 and 0.62. The updated ratio results in much more balanced Undeployed Regulating Mileage versus Additional Regulating Mileage. It also reduces the percentage of Undeployed Regulating Mileage Revenue Sufficiency Guarantee Credit. As a result, MISO has improved the efficient clearing and equitable settlement of the frequency regulation market by using the ratio that better reflects actual regulation deployment.

The Undeployed Regulating Mileage Revenue Sufficient Guarantee Credit has been a very small percentage of the regulation revenue and it has not caused any noticeable issues in the regulation market. The Informational Report provides additional analysis about this ratio. Since

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6 *Order on Compliance* at P 35.
7 *Id.* at P 39.
8 *Id.* at P 43.

the actual deployment ratio for fast ramping resources (with ramp rate more than 10 MW/Min) is higher than the actual deployment ratio for slow ramping resources (with ramp rate less than 3 MW/Min), the design results in higher Additional Regulating Mileage payments to fast-ramping resources. Moreover, fast-ramping resources also perform better than slow-ramping resources and, therefore, incur less performance penalty charges. These two factors provide fair compensation to resources that can provide better regulation service. Since the new design went into production, MISO has observed a slight shift of cleared regulation from slow-ramping resources to fast-ramping resources.

Finally, with regard to the factors that impact the resource tolerance band, MISO has been focused on analyzing system-wide patterns with regard to resource response accuracy measures to follow the Commission's requirement that RTOs and ISOs use the same accuracy measurement method for all resources.[9] That is, the RTO or ISO may not develop an accuracy metric that applies to one class of resources and another accuracy metric that applies to other resources. Doing so would move in the direction of creating a "fast" and "slow" regulation service which we have declined to do.

The percentages attributable to each of the listed factors that may impact the tolerance band vary by resource type and resource offers. For example, some resource types may have more nonlinear response impact than others. Additionally, data latency may cause a different percentage of impact on performance, especially when cleared regulation capacity changes from interval to interval. MISO's measurement approach is applied to all resources, regardless of how the percentages are attributed to any single factor.

The Informational Report shows that the 70% tolerance band is reasonable. For 2013, the actual five-minute following percentage is on average between 63% and 69%, all below the 70% threshold. At that threshold, between 52% and 60% of resources passed the five-minute interval performance accuracy test. The percentage of resources that can pass the hourly performance accuracy test, *i.e.*, not failing four consecutive five-minute interval performance accuracy test, is between 72% and 81%. The Informational Report provides additional analysis based on resource types and ramping capability. Fast-ramping resources generally perform better than slow-ramping resources. The ratio between the regulation penalty and regulation revenue for typical resource types ranges between 12.5% and 46.4%. The total annual regulation penalty charge is $11.5 million in 2013, which resulted in a much reduced net regulation payment of $19.9 million, compared to the payment of $26.1 million in 2012. The range of these charges demonstrates that the tolerance is not too narrow or too wide. Instead, the current tolerance band provides a reasonable goal for most resources to achieve at most times. Given the high percentage of total penalty charges and sufficiently good operational performance, MISO does not anticipate any need to tighten the performance tolerance at this time.

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[9] *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied*, Order No. 755-A, 138 FERC ¶ 61,123 at P 6 (2012).

III. DOCUMENTS INCLUDED WITH THIS FILING

MISO includes with this Transmittal Letter, an informational report entitled "Regulating Mileage Year One Analysis" at Attachment A.

Please contact the undersigned with any questions related to the Informational Report.

Respectfully submitted,

/s/ Erin M. Murphy

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ATTACHMENT A

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Regulation Mileage Year One Analysis

Information Delivery and Market analysis
The Midcontinent Independent System Operator
February 6, 2014

Contents

Executive Summary

On December 17, 2012, the Midcontinent Independent System Operator ("MISO") implemented two-part regulation compensation in compliance with FERC Order No. 755, "Frequency Regulation Compensation in the Organized Wholesale Power Markets," to provide fair compensation to regulating resources based on the actual regulation service provided.

Year-one analysis does not reveal any significant operational issues with the implementation of Regulation Mileage. Moreover, several positive outcomes have been noted since the implementation:

1) MISO's implementation of regulation mileage is working as designed by providing appropriate regulation compensation based on actual regulation mileage performance.
   a. As expected, overall regulation market clearing prices have increased slightly.
   b. More regulation capacity is also available for substitution for contingency reserves.

2) Overall regulation procurement costs and penalty charges have been relatively steady since the implementation of the regulation mileage enhancement. The net regulation payment to regulating resources in 2013 was $19.9 million, much lower than the payment of $26.1 million in 2012, and mainly driven by regulation performance penalty charges of $11.5 million.

3) Two-part regulation compensation provides fair compensation to fast-ramping resources that can generally provide more and better regulation movement. This compensation method has incentivized existing fast-ramping resources to participate in the regulation market, with the benefit of slightly improved operational performance.
   a. The actual regulation deployment ratio for faster ramping resources is on average higher than slower ramping resources. It results in more regulation mileage payment to faster ramping resources.
   b. The performance of faster ramping resources is better than that of slower ramping resources and hence with less percentage of regulation penalty charges.
   c. Regulation has shifted slightly from slower ramping resources to faster ramping resources.
   d. CPS1 and BAAL data indicates that system control performance has improved slightly in 2013.

In summary, the implementation of the performance based regulation payment at MISO has met the goal of providing fair compensation to regulating resources based on the actual regulation service provided. Overall, the market has benefited from the performance based compensation mechanism.

Background

Regulation Mileage is the absolute value of the up and down movement, in MW, of a resource in response to Automatic Generation Control ("AGC") regulation deployment[1]. On December 17, 2012, MISO began Frequency Regulation Compensation for regulation mileage in addition to regulation capacity in compliance with FERC Order No. 755. The intent of FERC Order No. 755 is to eliminate unduly discriminatory and preferential regulation compensation by requiring ISOs to compensate frequency regulation resources based on the actual regulation service provided. Accordingly,

- The Regulating Reserve Offer is now divided into two parts in both the Day-Ahead and Real-Time markets: Regulating Capacity Offer ($/MWh) and Regulating Mileage Offer ($/MW).
- The two regulation offers are summed into one Regulating Total Cost ($/MWh). The Regulating Total Cost is used in the market clearing engines to clear regulation capacity.
- A Deployment Ratio, updated monthly, is applied to the Regulating Mileage Offer.
- Regulating Total Cost ($/MWh) = (Regulating Capacity Offer ($/MWh) + Deployment Ratio * (Regulating Mileage Offer ($/MW)) * 12
- The Regulating Mileage Offer is considered with the Regulating Capacity Offer during market clearing in order to avoid an incentive to offer high regulating mileage but low regulating capacity.

Regulation Market Clearing Prices ("MCP") are divided into a regulating reserve MCP and a regulating mileage MCP in the Real-Time market only. When the Regulating Mileage Target from the actual deployment instruction is above the Regulating Mileage considered in the clearing processes, resources will be paid for Additional Regulating Mileage at the Regulating Mileage MCP. Otherwise, when the Regulating Mileage Target is below the Regulating Mileage considered in the clearing processes, resources will be charged back for Un-deployed Regulating Mileage at the Regulating Mileage MCP.

MISO started with using a "1:1" Deployment Ratio in the market clearing processes. Effective February 1, 2013, the deployment ratio is adjusted monthly based on actual observed operational regulation deployment data from the 15th of the previous month to the 15th of the current month.

- December 17th – February 1st: Deployment ratio = 1 per dispatch interval
- After Feb 1st 2013: Deployment ratio is approximately 0.60

MISO also implemented regulation performance accuracy measurement to compensate regulating resources based on the actual performance. Performance is measured at every 5-minute Dispatch Interval and every hour. A resource is paid or charged accordingly, based on the results of performance tests as follows. A resource will receive discounted Additional Regulating Mileage payment for a 5-minute Dispatch Interval if it fails the 5-minte regulation performance test and will not receive any regulating reserve or regulating mileage payment if it fails the hourly regulation performance test.

[1] The MW movement for energy or contingency reserves is not counted towards Regulation Mileage.

Market and Operational Observations

1. Regulation Market Clearing Prices

The figures below show the monthly average of Regulation MCP for the Day-Ahead and Real-Time markets during each month of year 2013. Regulating Reserve MCP increases slightly compared to the year 2012 (Figure 1a and 1b).

Figure 1a: Comparison of 2012 and 2013 monthly average Real-Time Regulating Reserve MCP

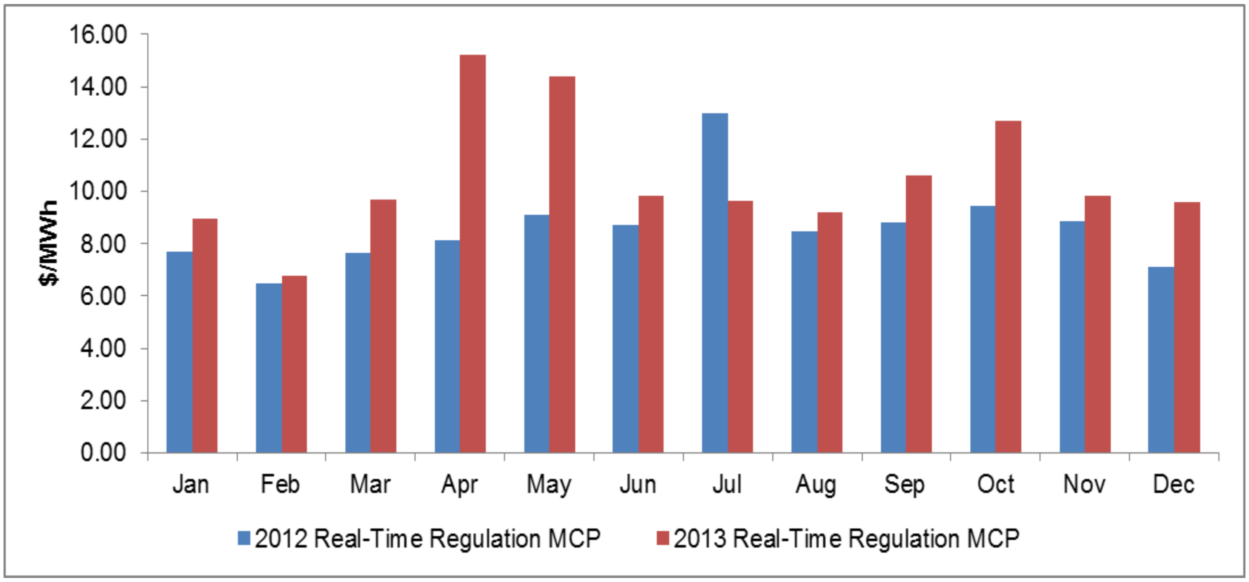


Figure 1b: Comparison of 2012 and 2013 monthly average Day-Ahead Regulating Reserve MCP

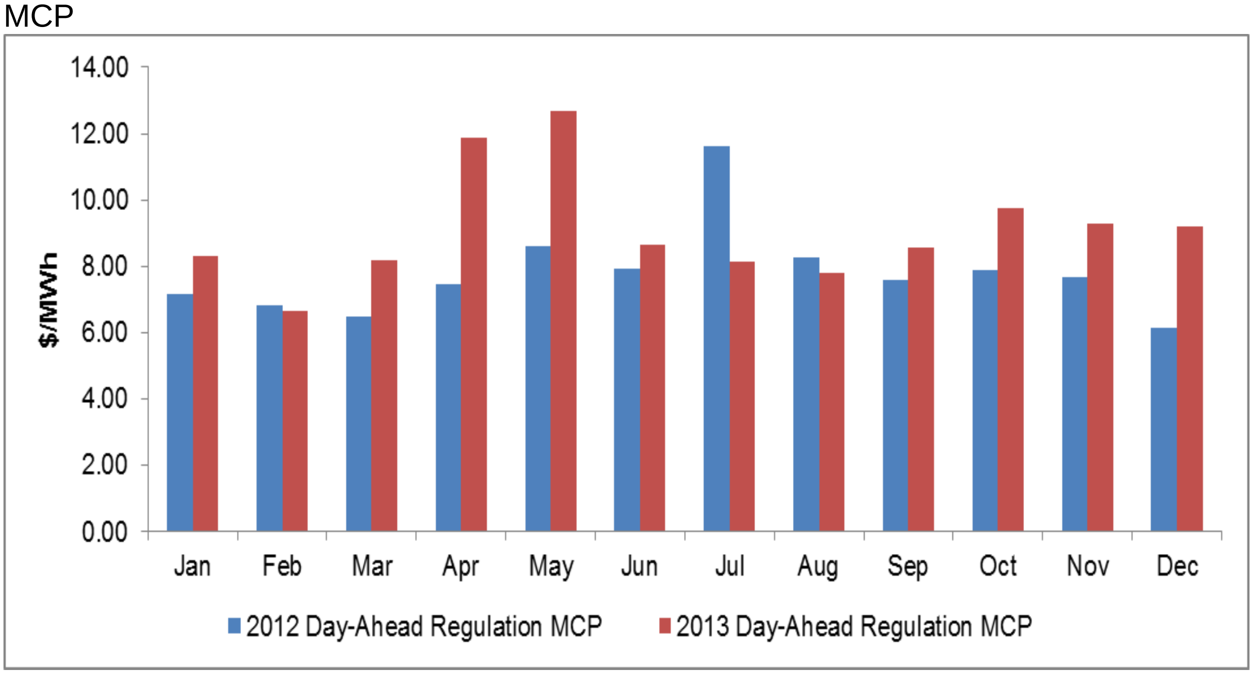
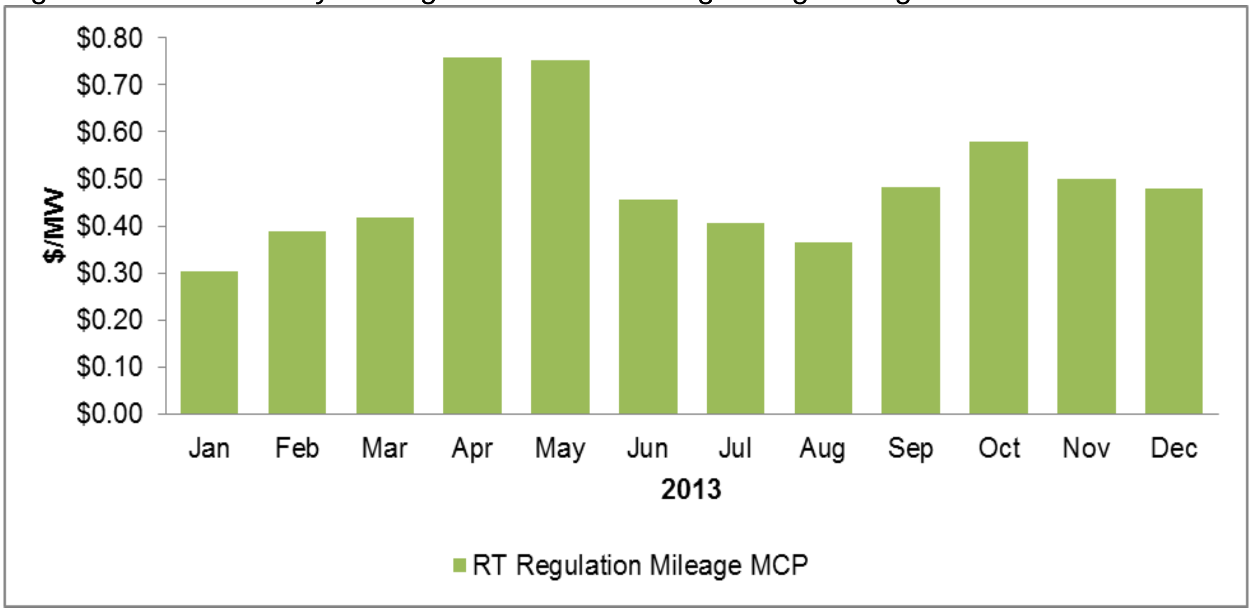


Figure 2: 2013 Monthly average of Real-Time Regulating Mileage MCP*



**Regulation Mileage MCP is applicable only to the Real-Time market*

High Real-Time Regulation MCP in April and May of 2013 was impacted mainly by operating reserve scarcity. It is expected that market participants will continue to adjust their biding strategy, as regulation mileage compensation is a relatively new enhancement in MISO's ancillary service market.

2. Regulation Substitution for Spinning Reserve

Prior to the implementation of the two-part regulation offer and compensation, Regulating Reserve Offers were overall higher than Contingency Reserve Offers. Hence, the amount of regulation capacity substituting for contingency reserves is very small. With the implementation of the two-part regulation offer, MISO revised the tariff to only account for the Regulating Capacity Offer for the portion of Regulating Reserve used to meet Contingency Reserve requirements. This change has resulted in cheaper regulation capacity available to substitute contingency reserves. Figure 3 below shows that the monthly average of the hourly regulation capacity substituted for Spinning Reserve in the Day-Ahead and Real-Time markets has increased since December 17, 2012. Figure 4 shows that the monthly average of hourly regulation capacity substituted for spinning reserve is close to zero before regulation mileage implementation.

Figure 3: Monthly average of hourly system-wide Regulation substitution for Spinning Reserve

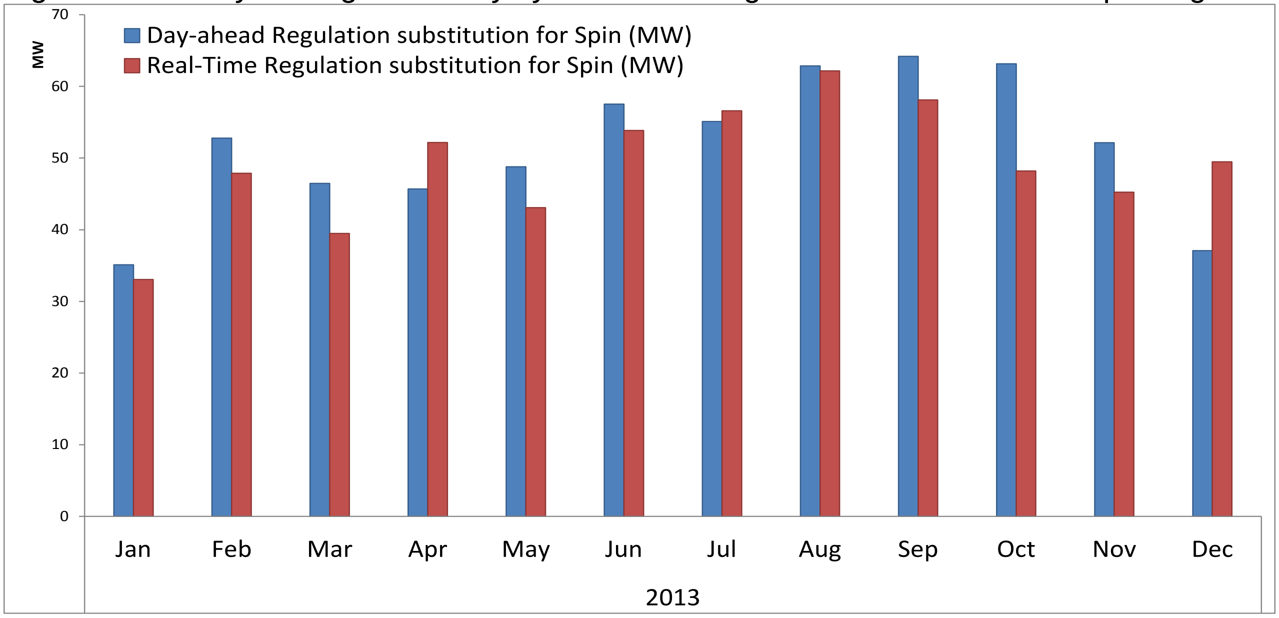
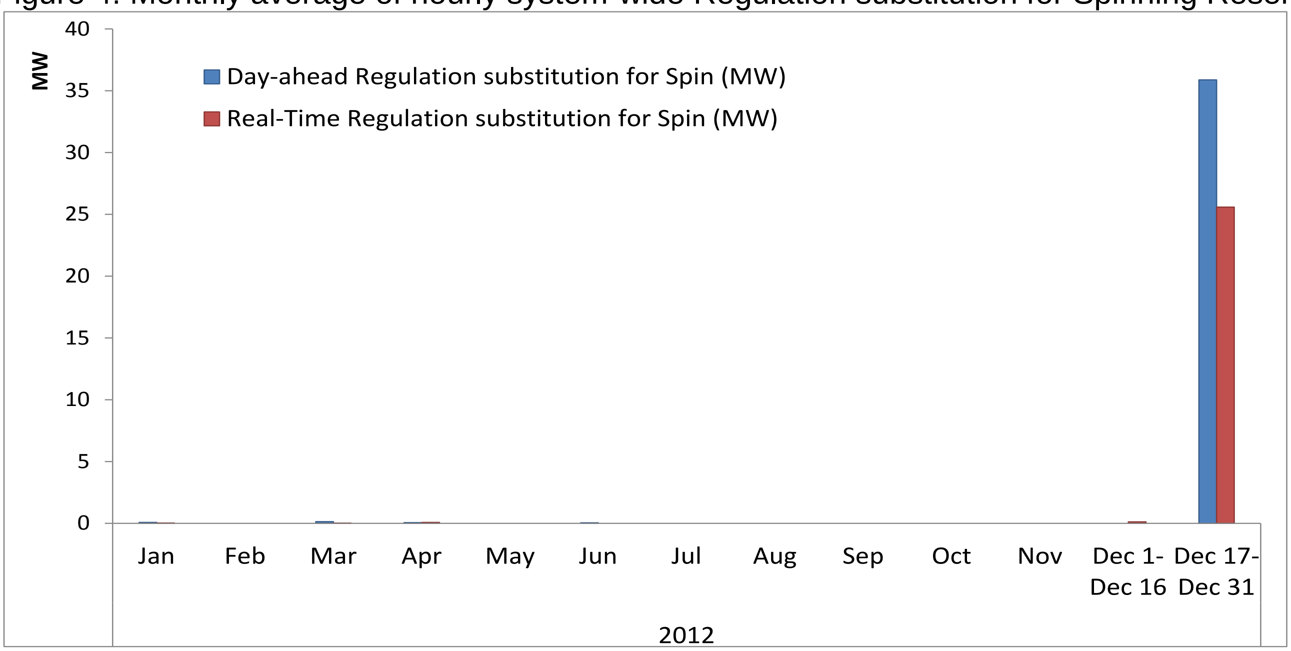


Figure 4: Monthly average of hourly system-wide Regulation substitution for Spinning Reserve



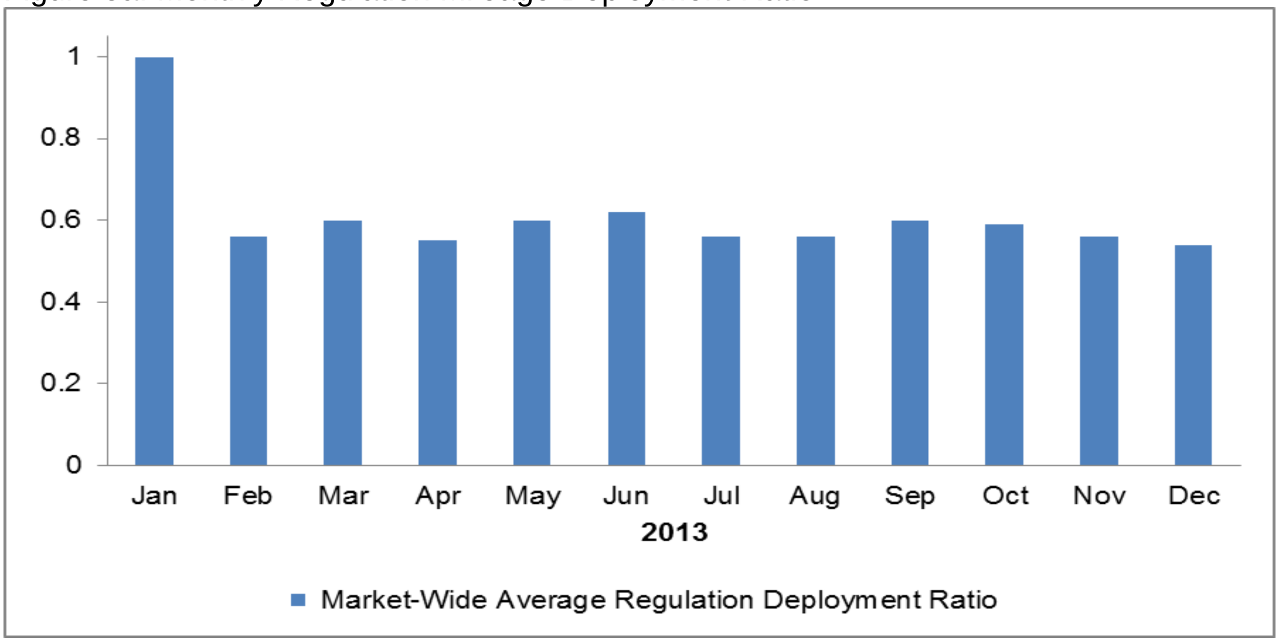
3. Regulation Deployment Ratio

Definitions

- **Regulation Deployment Ratio** is, for each resource, the ratio between Regulating Mileage Target MW and cleared Regulating Capacity MW calculated for the indicated time period.

On February 1, 2013, the Market-Wide Regulating Reserve Deployment Ratio was adjusted from an assumed full deployment per interval, to a value that accounts for the actual amount of mileage deployed. The Regulation Mileage Deployment Ratio is updated monthly based on data from the 15th of the previous month to the 15th of the current month. The ratio is used to combine Regulating Capacity Offer and Regulating Mileage Offer into Regulating Total Cost. For example, a resource's Regulating Total Cost equals to *Regulating Capacity Offer ($/MWh) + Regulating Mileage Offer ($/MW) * 12* * 0.60 for the month of May 2013 (Figure 5a).

Figure 5a: Monthly Regulation Mileage Deployment Ratio



By implementing a regulation deployment ratio based on actual mileage deployed on February 1, 2013, the Undeployment Regulating Mileage charge and Additional Regulating Mileage payment become much more balanced as shown in Figure 5b. The Un-deployed Regulating Mileage Revenue Sufficient Guarantee Credit decreased as expected, as shown in the figure 5c below. Hence, MISO improved the efficient clearing and equitable settlement of the frequency regulation market by using the regulation deployment ratios to better reflect the actual deployment in the system. The Un-deployed Regulating Mileage Revenue Sufficient Guarantee Credit has been a very small percentage of the regulation revenue and it has not caused any noticeable issues in the regulation market.

Figure 5b: Monthly averages of daily Undeployed Regulating Mileage and Additional Regulation Mileage

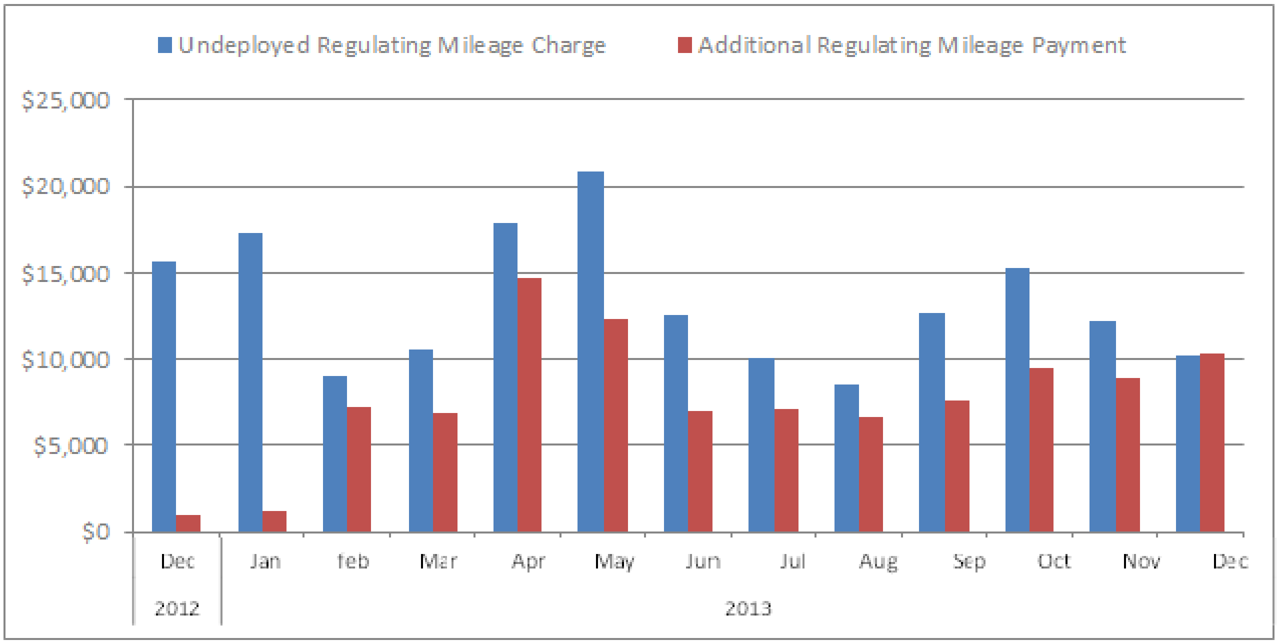
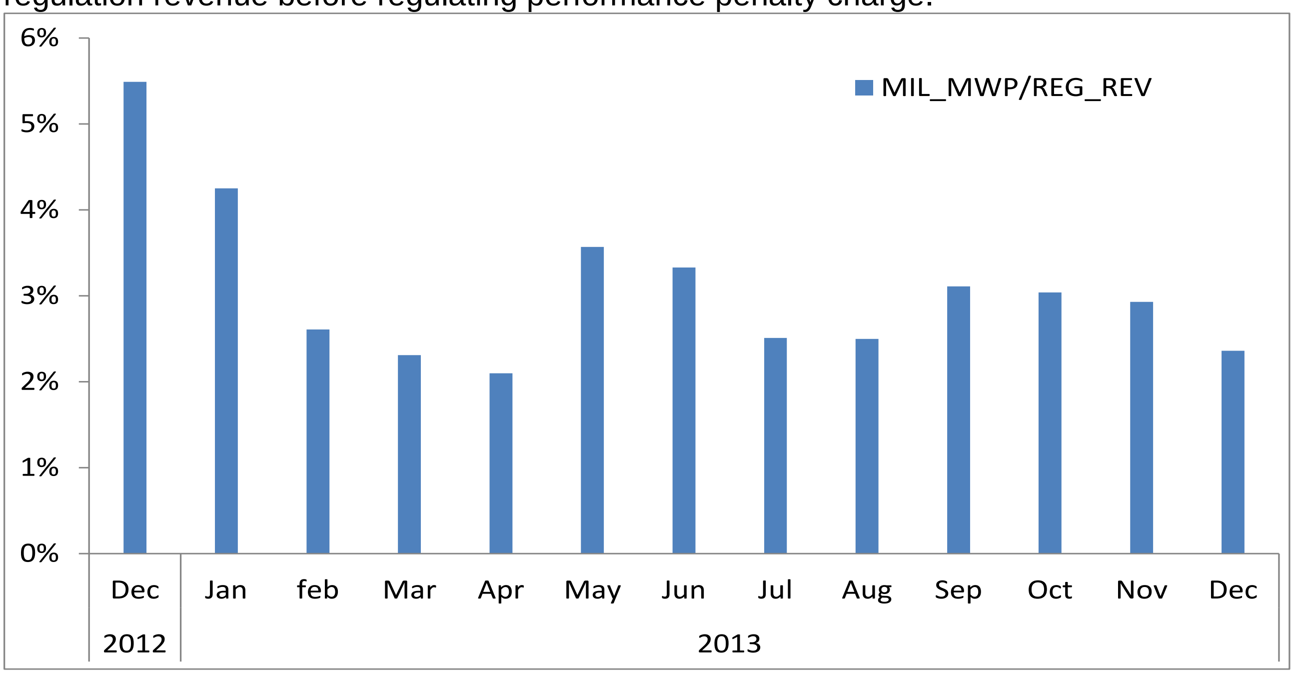


Figure 5c: Ratio between Un-deployed Regulating Revenue Sufficient Guarantee Credit and regulation revenue before regulating performance penalty charge.



4. Regulation Performance

MISO pays regulation based on resources' regulation performance. Figure 7 shows the performance measurement indices:

- **Regulation Mileage Follow Performance** ("Follow per Average") is the average percentage of resources that followed set-point instructions during each 5-minute

Dispatch Interval. It is measured as the percentage of the Actual Resource Response provided by a resource in each Dispatch Interval to its Desired Resource Response from MISO set-point instruction. If the Regulation Mileage Follow Performance index is above 70% for a 5-minute Dispatch Interval, then a resource passes the Performance Accuracy Measurement Test for that interval. If a resource fails the Performance Accuracy Measurement Test for a Dispatch Interval, its Additional Regulating Mileage payment is discounted.

- **Regulation Mileage 5-minute Performance** ("5-Minute Average") is the average percentage resources passed the 5-minute Performance Accuracy Measurement Test.
- **Regulation Mileage Hourly Performance** ("Hourly Average") is the average percentage of resources that passed the hourly Performance Accuracy Measurement Test, i.e., not failing the 5-minute Performance Accuracy Measurement Test for four consecutive Dispatch Intervals in an hour. If a resource fails the hourly Performance Accuracy Measurement Test, it loses all the regulating reserve payments for that hour.

MISO places a penalty on resources that fail the 5-minute performance test and/or the hourly performance test. A low hourly performance passing percentage may indicate that the threshold for the mileage performance test may be too high or that resources do not follow set-point instruction adequately.

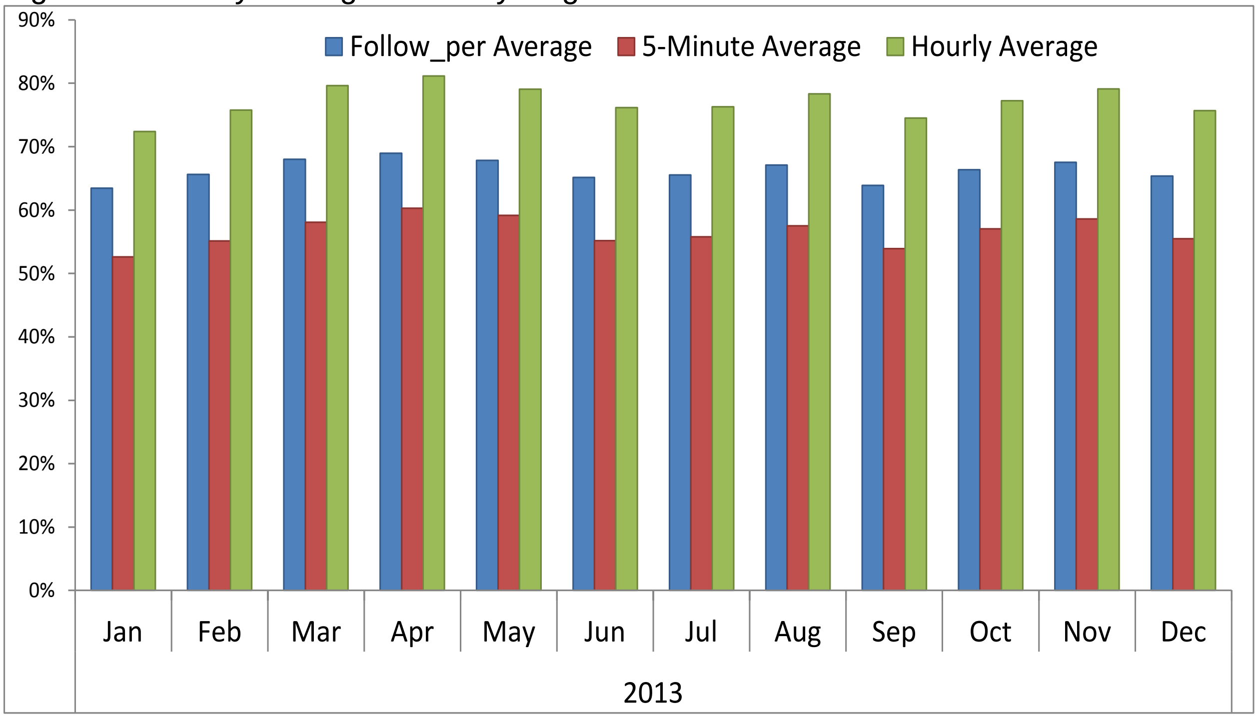
Figure 6 below indicates that the monthly average of hourly regulation mileage performance has been steady during the year 2013. On a monthly average basis, regulation resources pass the hourly regulation mileage performance test 77% of time. The result indicates that resources lose the entire regulating reserve payment for 23% of the hours on a monthly average basis.

Figure 6 also shows that the hourly regulation mileage performance has improved over the first four months of 2013, and has been hovering around at 77% after May. This performance is an indication that the 70% tolerance is certainly not an easy to pass criterion. It incentivizes resources to improve performance, while simultaneously keeping the penalty charge within a reasonable amount.

The regulation performance penalty charges are not trivial as shown in Section 5. The market has received about $11.5 million in payment from the implementation of performance-based regulating payment.

Section 6 shows the analysis by ramp type. It indicates that fast-ramping resources overall perform much better than slow-ramping resources and the performance penalty charges account for a much lower percentage of the gross regulation revenue. Hence, the performance measurement criterion provides fair compensation based on the regulation service provided by regulating resources.

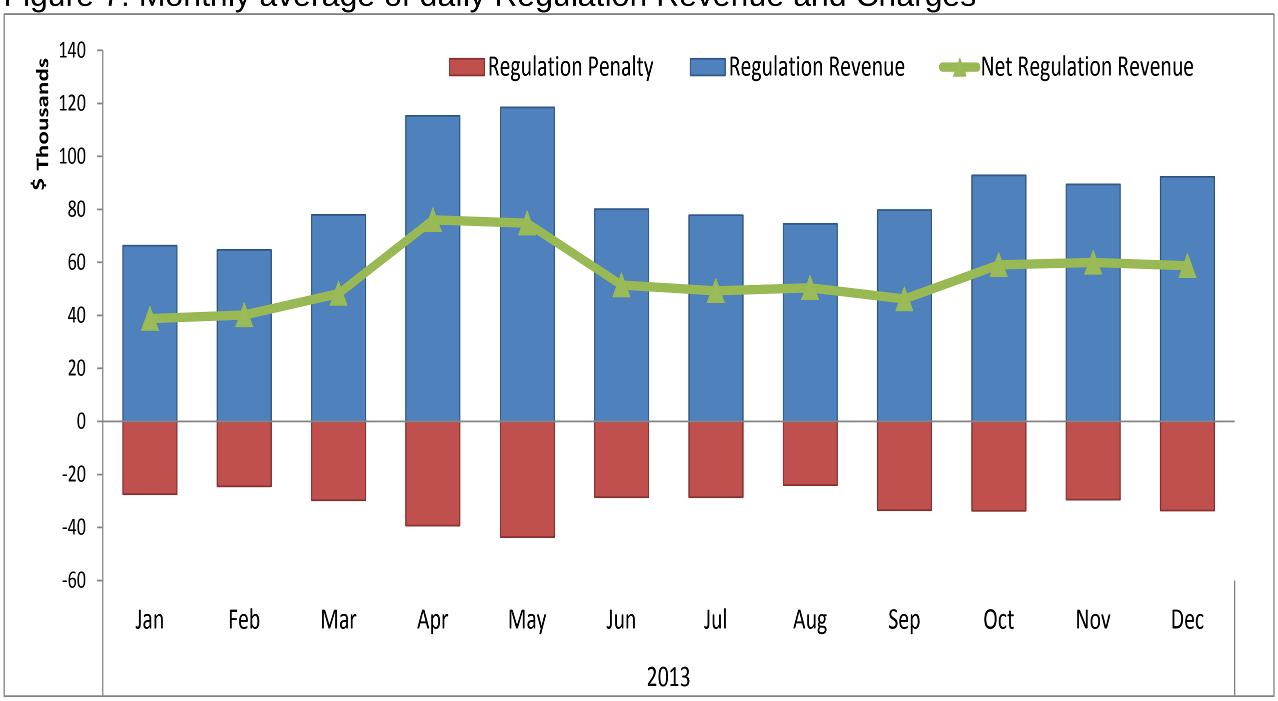
Figure 6: Monthly average of Hourly Regulation Performance



5. Regulation Mileage Based Payments and Charges

If a resource fails the 5-minte and the hourly mileage performance tests, the resource will be charged back part or all of the regulation revenue for that hour. Figure 7 below shows the daily average market-wide Real-Time settlement dollar values related to payments and charges to regulation resources.

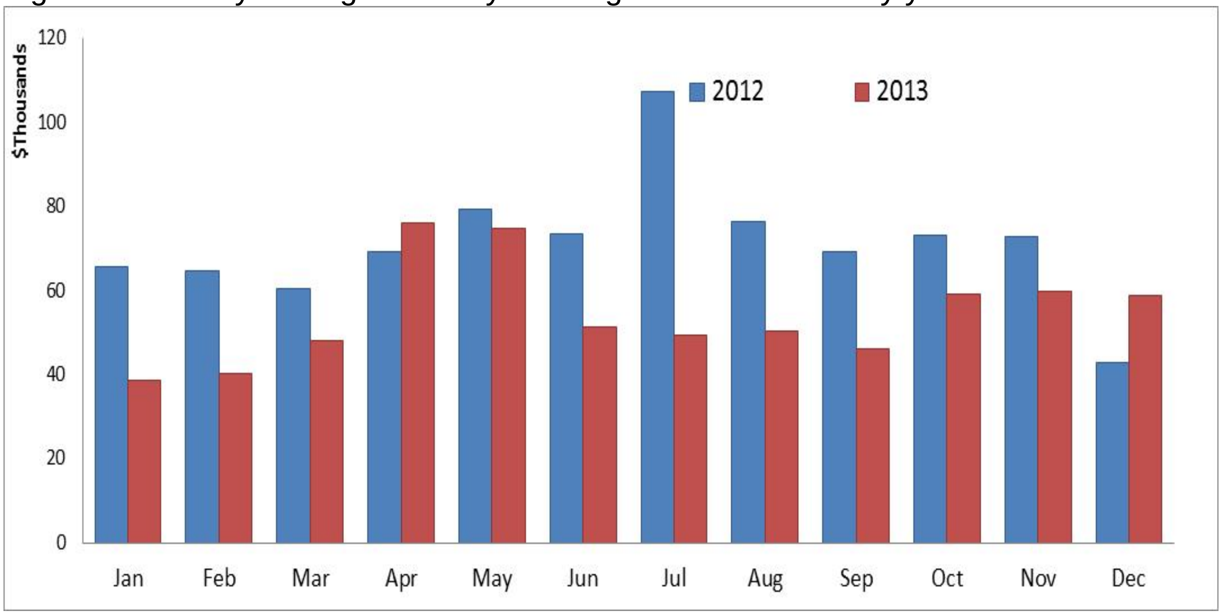
Figure 7: Monthly average of daily Regulation Revenue and Charges



A negative dollar sign indicates a charge to regulation resources and a positive dollar sign indicates a credit to regulation resources.

The daily averages of net Regulation Revenue have been steady since June 2013. The higher daily averages of net regulation revenue in April and May are mainly reflective of higher regulation MCP and improved regulation mileage performance.

Figure 8: Monthly averages of daily net Regulation Revenue by year



The daily averages of net regulation revenue after the implementation of regulation mileage are much lower than the values in 2012, mainly driven by regulation mileage performance penalty charges.

6. Ramp Rate Based Mileage Payment and Performance

The new regulation compensation should encourage fast-response regulating resources to participate in the regulation market, eventually improving the overall regulating performance.

In this report, a resource is defined as “fast-ramping” if its ramp rate is greater than or equal to 10 MW/min. Resource types that traditionally fall in this category are energy storage resources (such as flywheels and batteries) and fast-ramping gas turbines. A resource is defined as a slow-ramping resource if its ramp rate is less than 3 MW/min, which mainly include coal-fired units. All other units fall into a “middle” category. Table 1 summarizes the average bidirectional ramp rate offered into MISO real time market based on the resource type.

Table 1: Average Ramp Rate by resource type

Resource type	Average Ramp Rate (MW/min)
Steam Turbine	2.0
Combustion Turbine	6.6
Pumped Storage	9.6
Combine Cycle Aggregate	6.4
Demand Response Unit - Type 2	5.3
Stored Energy Resource	120
Hydro	3.8

Cleared regulation reserve volumes, hourly and 5-min mileage performances, and regulation payments are sub-divided by the three ramp categories to show the impact of regulation mileage compensation on resources with different ramping capabilities.

Figures 9a-9c show the distribution of cleared regulation among the three ramping categories. It was noted that the cleared Day-Ahead and Real-Time Regulation volume for faster ramping units showed seasonal pattern during the year 2013. Figure 9c shows the trend of regulation capacity shifting from slower ramping resources to faster ramping resources after the implementation of regulation mileage payment.

Figure 9a: Monthly average of daily total cleared Day-Ahead regulation volume by Ramp Type

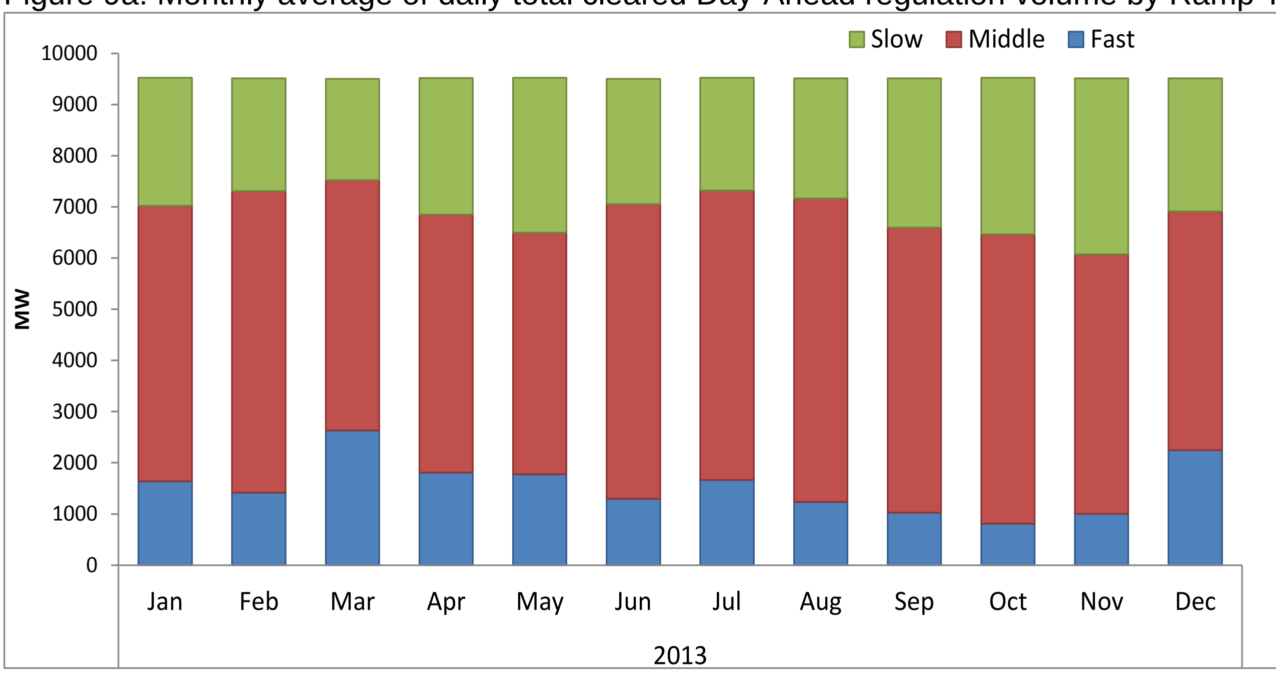
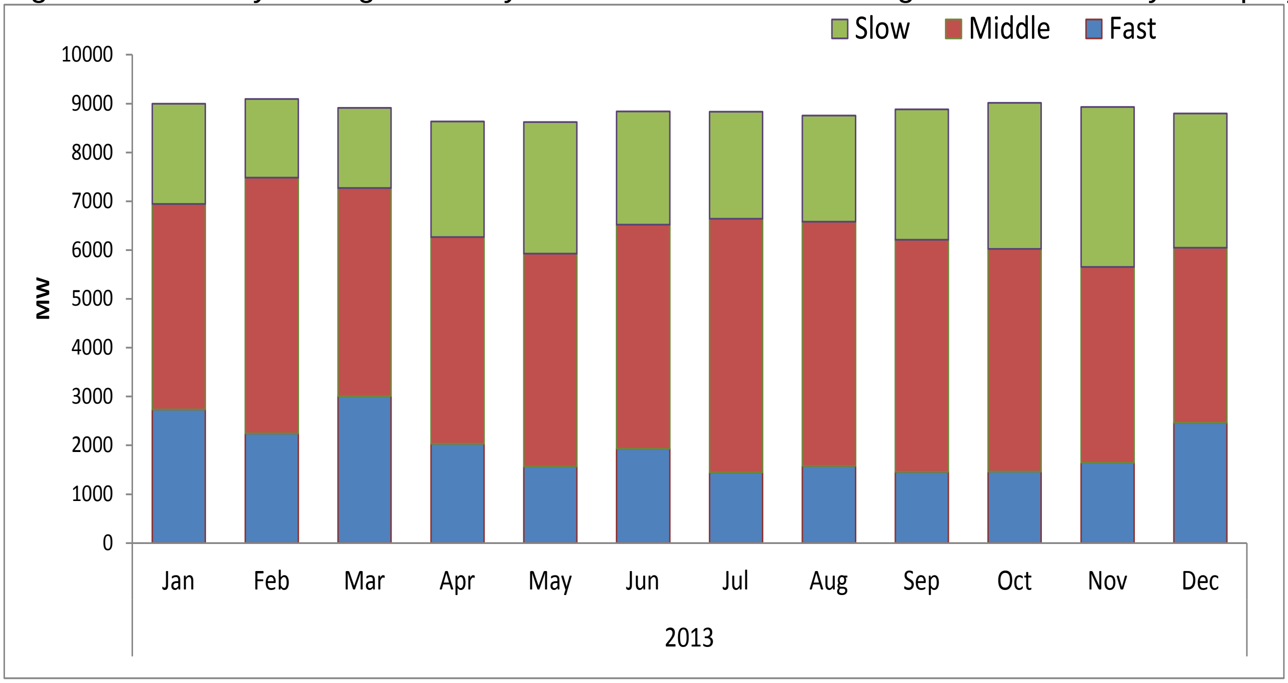


Figure 9b: Monthly averages of daily total cleared Real-Time regulation volume by Ramp Type



**Fast ramp (>=10 MW/min); Slow ramp (< 3 MW/min)*

Figure 9c: Averages of hourly cleared Regulation volume by Market, Ramp Type and Year

Figures 10a-10c show the regulation performance by ramp types. The figures show that, on monthly average basis, the overall regulation mileage performance for faster ramping resources are much better than the performance of the slow ramping resources.

Figure 10d shows the monthly average 5-minute regulation deployment ratio by ramp type. The deployment ratio for faster ramping resources are higher than the ratio for slower ramping resources. Accordingly, faster ramping resources receive more Additional Regulating Mileage payments and less Undeployed Regulation Mileage charges. The regulating mileage compensation provides fair compensations for resources with fast-ramping capability.

Figure 10a: Monthly average of hourly Regulation Mileage Performance by Ramp Type

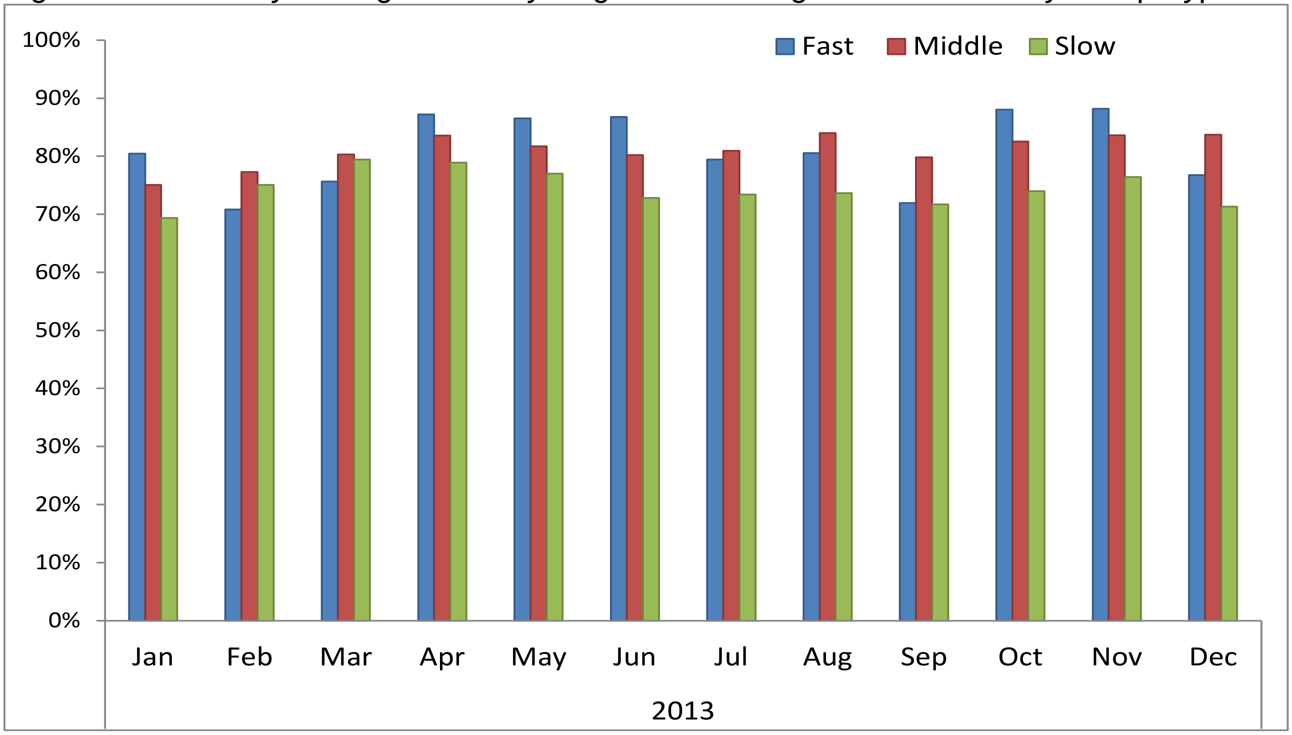
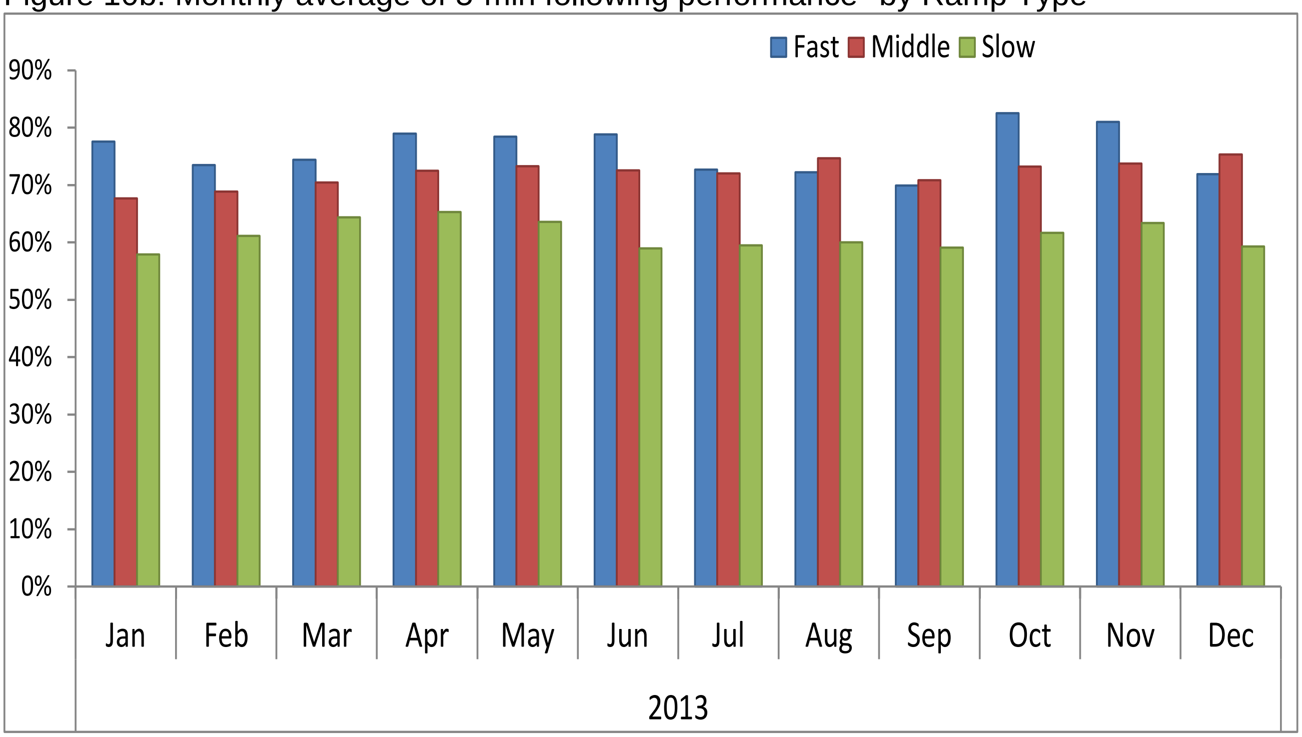
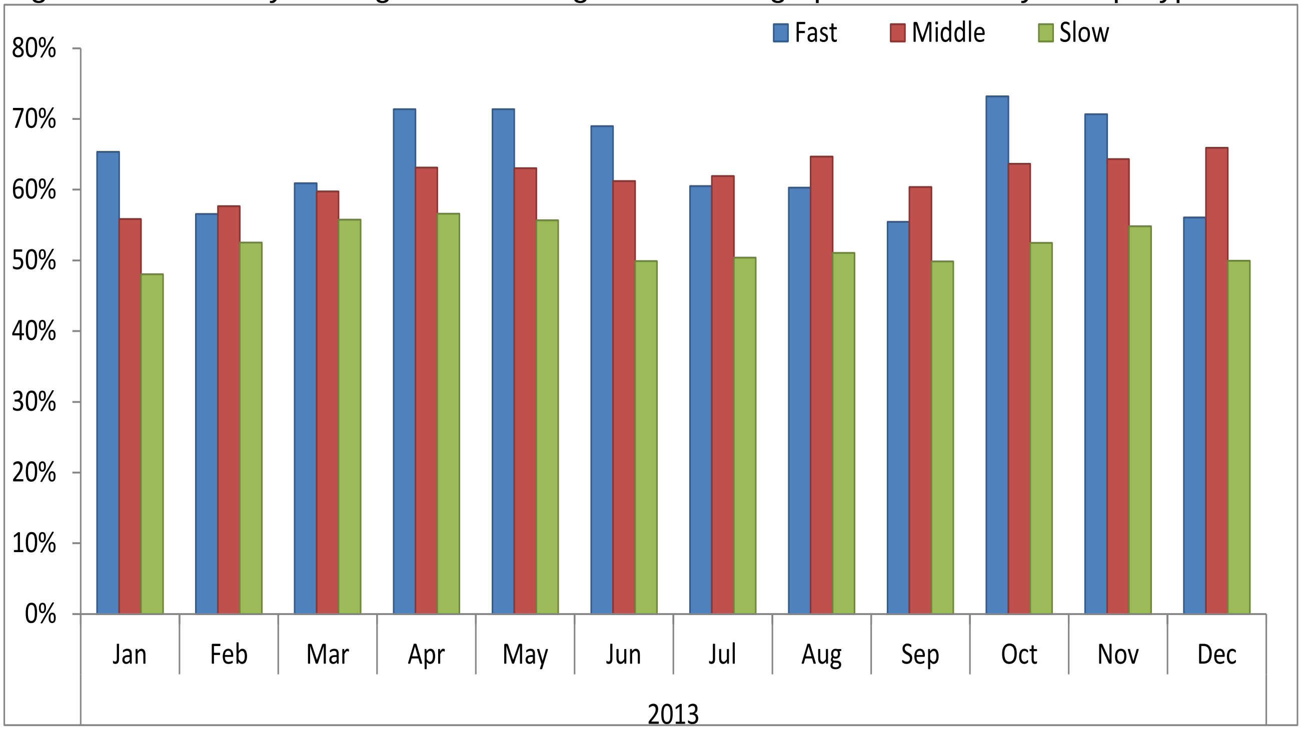


Figure 10b: Monthly average of 5-min following performance* by Ramp Type



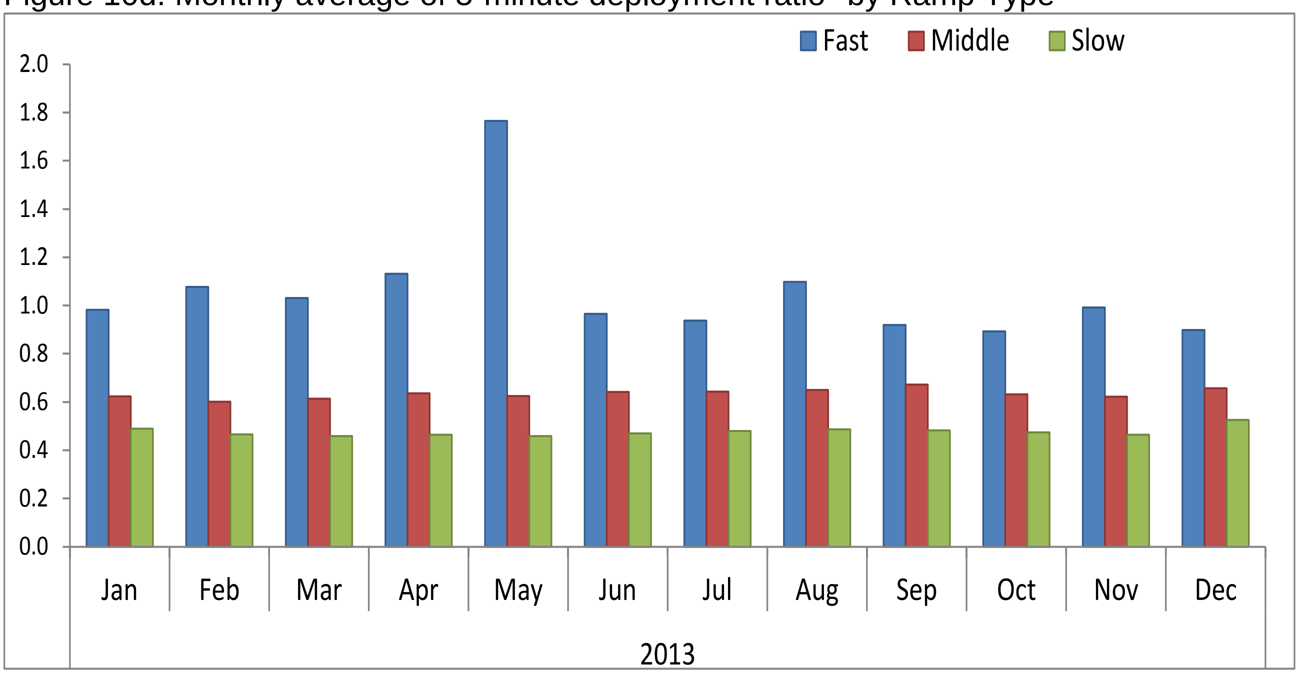
Regulation Mileage Follow Performance is the average percentage resources followed set-point instructions.

Figure 10c: Monthly average of 5-min regulation mileage performance by Ramp Type



Regulation Mileage 5-minute Performance is the average percentage resources passed the 5-minute "failure mileage performance test".

Figure 10d: Monthly average of 5-minute deployment ratio* by Ramp Type



**Regulation Deployment Ratio for each resource is the ratio between Regulating Mileage Target MW and cleared Regulation MW for each 5-minute Dispatch Interval.*

MISO makes regulation payments based on a resource's regulation mileage performance. Performance can be measured as a percentage of the regulation penalty charge relative to the regulation payment. The lower the percent value, the better mileage performance (i.e. the

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better the resource is at following AGC signal). It is expected that fast-ramping resources would perform better than slower ramping resources.

Figures 11a-11c below show the monthly averages of daily regulation payment and charge for each ramp rate category. The figures indicate that the mileage performance of fast-ramping resources is better when compared to the other types and hence has lower percentage of regulation penalty charge.

Prior to the implementation of regulation mileage, previous compensation methods for regulation services in MISO markets failed to acknowledge the large amount of frequency regulation service that was being provided by faster-ramping resources as compared to slower-ramping resources. The new regulation mileage design recognizes this contribution by fast-ramping resources and compensates regulation resources for their performance.

Figure 11a: Monthly averages of daily Regulation revenue and penalty for Fast Ramping Resources

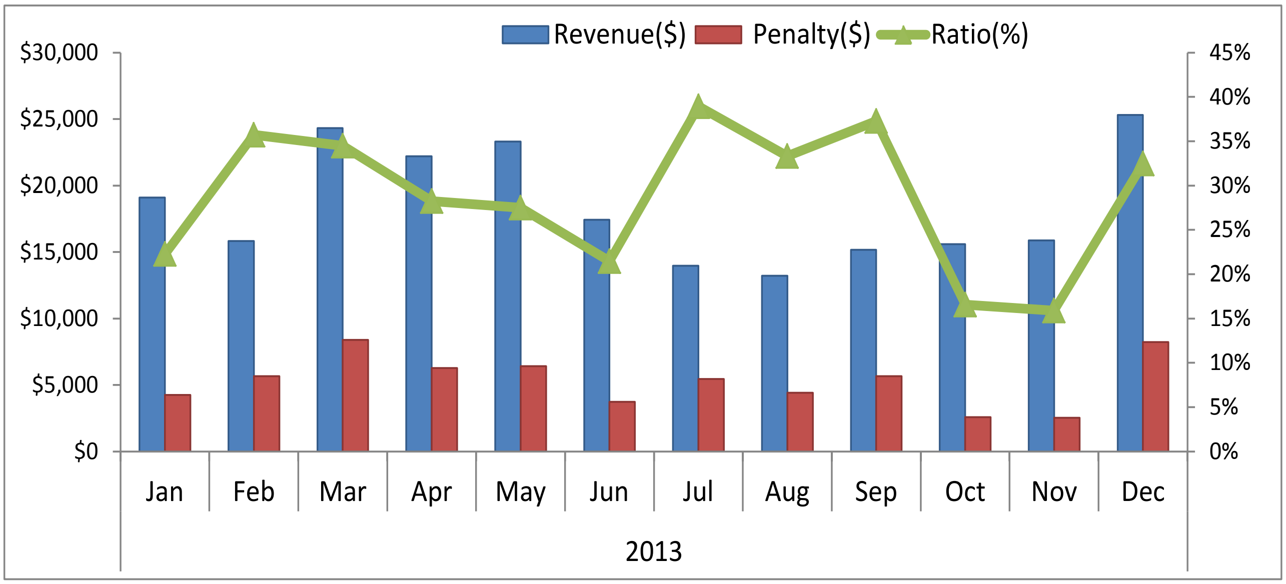


Figure 11b: Monthly averages of daily Regulation revenue and penalty for Middle Ramping Resources

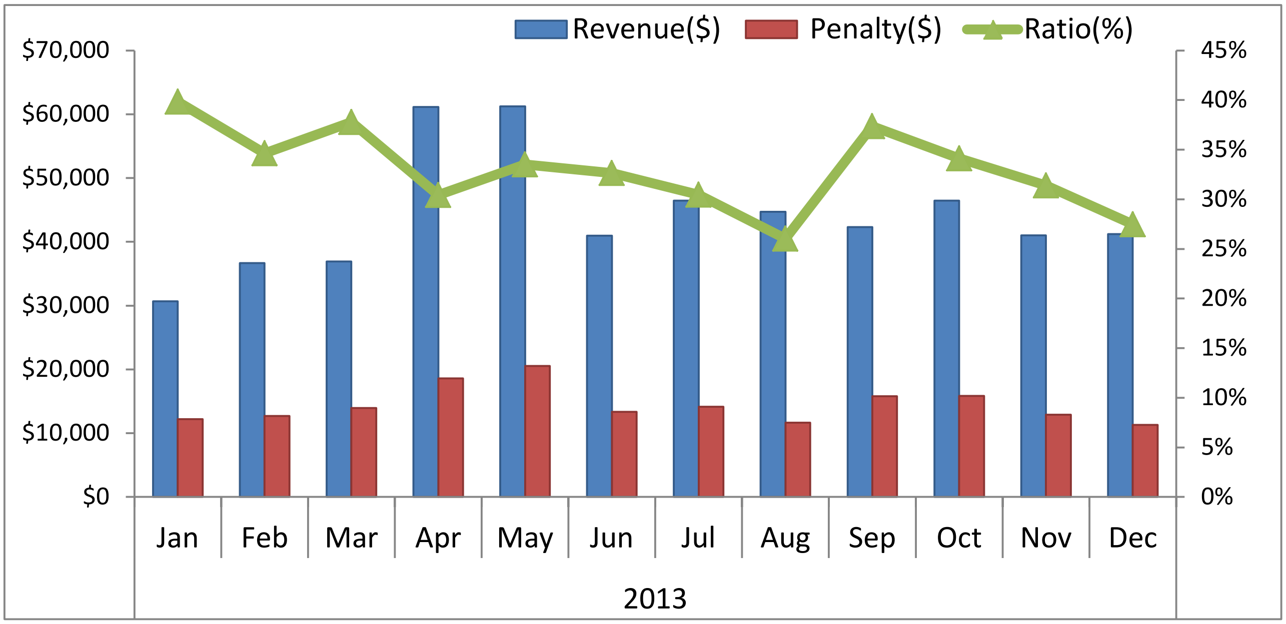
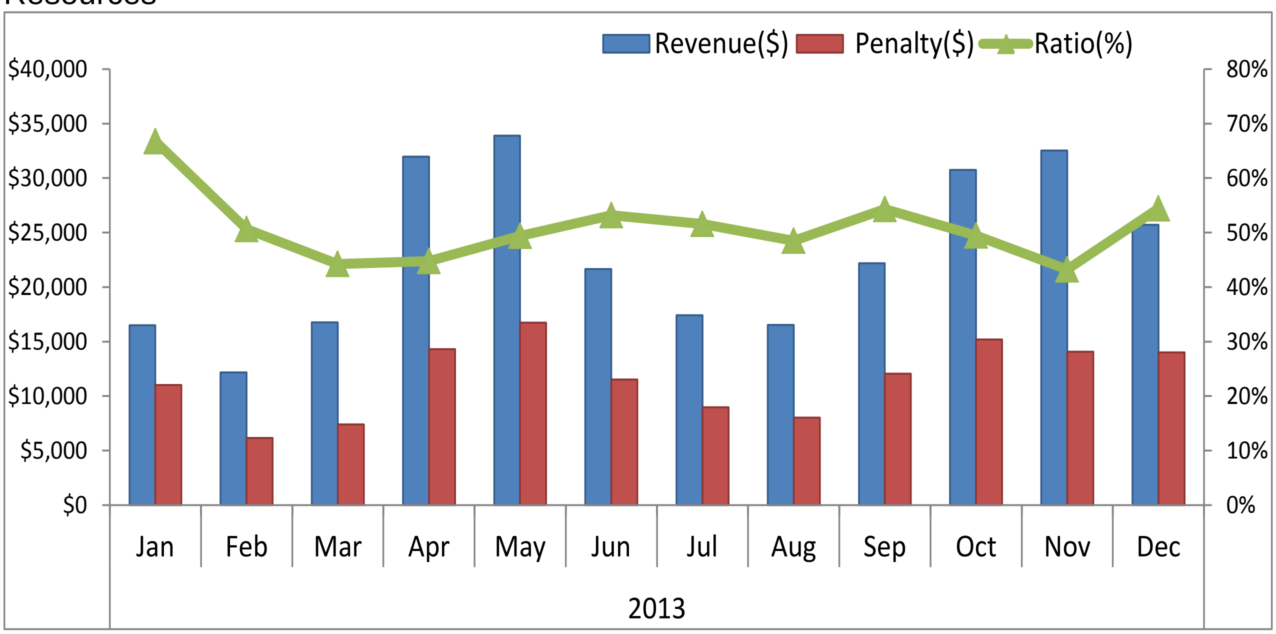


Figure 11c: Monthly averages of daily Regulation revenue and penalty for Slow Ramping Resources



**Ratio=Penalty/Regulation revenue*
#: penalty for not following

7. Resource Type Based Mileage Payment and Performance

This section compares the regulation payments and charges based on resource types.

Table 2: Average of monthly ratio* between Penalty# and Revenue (before penalty) for year 2013 by Resource Type

Resource Type	Ratio between Penalty and Revenue
Steam Turbine	46.40%
Combine Cycle	28.50%
Hydro	24.10%
Combustion Turbine	22.30%
Pumped Storage	18.60%
Demand Response Resource- Type 2	12.50%

#: penalty for not following

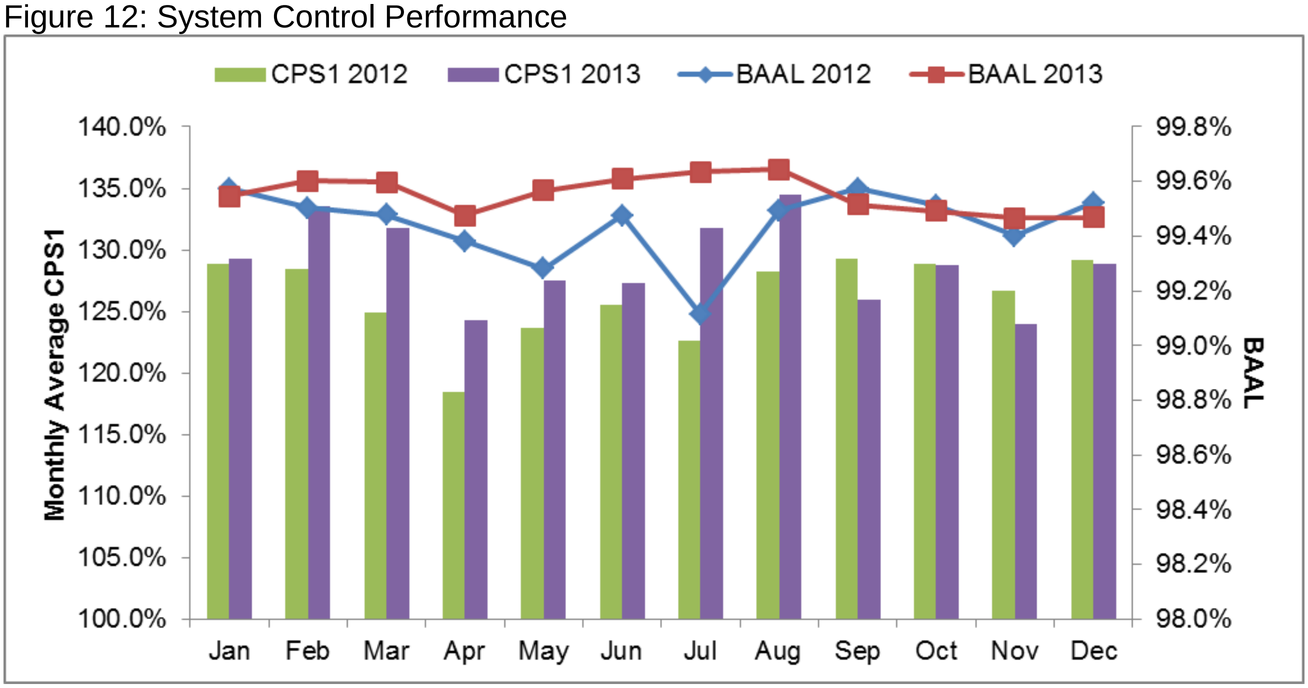
Note there is one small Stored Energy Resource in MISO market. It is not included in this report since it is only offered and cleared occasionally for testing purposes.

DRR type 2 has the best regulation performance. The ratio of 12.5% between the penalty and revenue indicates that the performance measurement criteria are not too wide. The steam turbine resource has the worst mileage performance with 46.4% of the performance penalty charges, as it mainly includes the slow ramping coal-fired units.

8. Operational Observations

Regulating reserves procured through MISO's Day-Ahead and Real-Time markets are used for secondary system control. MISO uses both the Control Performance Standard 1 (CPS1) and the Balancing Authority Area Control Error (ACE) Limit (BAAL) to measure system control performance. MISO's CPS1 and BAAL data for 2012 and 2013 are plotted in Figure 13 for comparison. The BAAL metric, in the figure, is the percentage of time MISO's ACE is within limit, *i.e.,* greater than $BAAL_{Low}$ Limit or less than $BAAL_{High}$ Limit. Figure 13 indicates that system control performance overall improved slightly in 2013.

Figure 12: System Control Performance



Conclusion

MISO's implementation of regulation mileage has been successful since December 17, 2012 The regulation market net regulation payment in 2013 was much less than the payment in 2012, even though the average regulation clear prices in 2013 were higher than 2012. System control performance has been improved slightly as measured by CPS1 and BAAL. The performance based regulation mileage compensation has incentivized the fast ramping resources to participate the market, as evidenced by the slight increase of regulation cleared on fast ramping resources. As expected, the fast ramping resources also have much higher regulation deployment ratio and better regulation performance as compared to slow ramping resources.

Document Content(s)

Exhibit No. IPL-6

Essential Reliability Services Task Force Measures Framework Report

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Essential Reliability Services Task Force Measures Framework Report

November 2015

RELIABILITY | ACCOUNTABILITY

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Suite 600, North Tower
Atlanta, GA 30326
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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
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

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

- **Impact of Retirements:** Conventional units such as coal plants provide frequency support services as a function of their large spinning generators and governor control settings along with reactive support for voltage control. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available.
- **Replacement Resources:** As the generation resource mix evolves, the reliability of the electric grid depends on the operating characteristics of the replacement resources. Gas-fired units, VERs, storage, and other resources are equipped to provide similar reliability services; however, the functionality may not always be installed or made available due to costs or market rules. The controllability of new generator and load resources to maintain the balance between load and generation, especially during ramping periods, is necessary to ensure reliability.
- **Resource Capability and Characteristics:** The reliability of the BPS depends on the operating characteristics of the replacement resources. Merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the electric grid to have resources with the capability to provide sufficient amounts of these services and maintain system balance.

The purpose of this report is to explore important directional measures to help the industry understand and prepare for the increased deployment of VERs, retirement of conventional coal units, advances in demand response technologies, and other changes to the traditional characteristics of generation and load resources.

The ERSTF is not asserting that it has developed the final answer to this complex transformation; rather, the group is presenting concepts and proposing measures based on discussions with system operators, planners and industry experts studying these issues. The task force looked closely at the BPS, especially areas that are experiencing the greatest level of change in the types of resource used to serve their load. While the behaviors of conventional generators are well documented, the task force also reviewed the capabilities of newer technology such as wind, solar, battery storage and other types of generators. The ERSTF had discussions with CAISO, ERCOT, IESO, and others experiencing significant transitions in generation resource mix. Based on these discussions and other sources of information, the ERSTF has concluded that the generation resource mix transition can and does have a profound impact on the transmission and distribution infrastructure and, while manageable, these impacts have to be accounted for in energy policy making, system planning, and system operations.

In order to maintain an adequate level of reliability through this transition, generation resources need to provide sufficient voltage control, frequency support, and ramping capability—essential components of a reliable BPS.

Creation of the ERSTF

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

Objectives of the ERSTF

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

Summary of Measures and Industry Practices

The task force found that the most important essential reliability services (ERS) for reliability largely focus on the topics of managing frequency, net demand ramping, voltage, and dispatchability. At the highest level, the recommendations can be summarized as:

- **Frequency –** These recommendations relate to restoring frequency after an event such as the sudden loss of a major resource. The frequency within an interconnection will immediately fall upon such an event, requiring a very fast response from some resources to slow the rate of fall, a fast increase in power output (or decrease in power consumption) to stop the fall and stabilize the frequency, then a more prolonged contribution of additional power (or reduced load) to compensate for the lost units and bring system frequency back to the normal level. The task force recommends measures to track the minimum frequency and frequency response following the observed contingency events, track and project the levels of conventional synchronous inertia for each balancing area and the interconnection as a whole, and track and project the initial frequency deviation in the first half-second following the largest contingency event for each interconnection.

- **Ramping –** Ramping is related to frequency, but more in an “operations as usual” sense rather than after an event. Changes in the amount of non-dispatchable resources, system constraints, load behaviors and the generation mix can impact the ramp rates needed to keep the system in balance. The task force recommends a measure to track and project the maximum one-hour and three-hour ramps for each balancing area. Reporting these individual BA values at the NERC level will provide data for industry-wide trending and assessment of the interaction between BAs.

- **Voltage –** Voltage must be controlled to protect the system and move power where it is needed. This control tends to be more local in nature, such as at individual transmission substations, in sub-areas of lower voltage transmission nodes and the distribution system. Ensuring sufficient voltage control and “stiffness” of the system is important both for normal operations and for events impacting normal operations (i.e., disturbances). The task force recommends a measure to track and project the static and dynamic reactive power reserve capabilities to regulate voltage at various points in the system. The task force also recommends that industry monitor events related to voltage performance, periodically review the short circuit current at each transmission bus in the network, and do further analysis of short circuit ratios when penetration of nonsynchronous generation is high or anticipated to increase.

The ERSTF sub-teams worked to define potential measures for study and consideration that will assist in evaluating the impacts on reliability services as a result of the change in generation mix. Each potential measure was assigned a reference number as shown in Table 1. The numbers are solely for the convenience of the task force and are not meant to suggest a priority or level of importance. The general goal when forming each potential measure was to define a value that could measure historical performance, project future performance, and be plotted for the detection and understanding of trends.

After analysis and discussion, the task force recommended that each potential measure be identified as a Measure, Industry Practice, or No Further Action item.

- A Measure means that the task force recommends that values should be calculated by the appropriate entity on a regular basis and tracked by the appropriate NERC committee, subcommittee, or task force going forward.
- An Industry Practice means that the analysis has value for the appropriate entity and its use is recommended, but the value is highly dependent on the context of the specific entity, so it is less useful to report and monitor the values at the NERC level.
- A No Further Action item may provide a useful example, but was not moved forward as a recommendation for the industry at this time.

General Recommendations

Overall, the ERSTF represents a focused approach to understanding system behavior that exists today, how this behavior may change in the future, what the system will require from resources in the future, and how to make the transition in a reliable way. New resources may have different operating characteristics but can be reliably integrated with proper planning, design, and coordination. Maintaining reliability is embodied in the predictability, controllability and responsiveness of the resource mix.

Recommendations include:

1. All new resources should have the capability to support voltage and frequency. Automatic voltage regulators and governors have been standard on conventional generators for decades, and comparable capabilities are currently available for new VERs and other resources. Ensuring that these capabilities are present in the future resource mix is prudent and necessary.
2. Monitoring of the Measures and investigation of trends. The Measures are intended to highlight aspects of reliability that could suggest future reliability concerns if not addressed with suitable planning and engineering practices.
3. Planning and operating entities should use the Industry Practices. While the results of Industry Practices will be system specific and difficult to quantify or compare between different regions, they will help ensure that emerging concerns are addressed with suitable planning and engineering practices.
4. While beyond the formal scope of the ERSTF, the task force recognized that Distributed Energy Resources (DERs) will increasingly affect the net distribution load that is observed by the BPS. The ERSTF recommends coordination of NERC Reliability Standards with DER equipment standards such as IEEE 1547. Pursuant with NERC's reliability assessment obligations, the ERSTF further recommends that NERC

establish a working group to examine the forecasting, visibility, control, and participation of DERs as an active part of the BPS. With prudent planning, operating and engineering practices, and policy oriented to support reliability, DERs should be able to be reliably integrated into BPS operation.

5. Open sharing of experiences and lessons learned. The reliability of the system can be maintained or improved as the resource mix evolves, provided that sufficient amounts of essential reliability services are available.

Recommended Ongoing Efforts

Under the coordination of the NERC Planning and Operating Committees, a clear approach should be established to ensure ongoing analysis and reporting of the Measures and to encourage the use of Industry Practices. The ERSTF believes that the Measures provide useful trends and insights into the current challenges in certain areas of North America as related to the changing resource mix that should be monitored going forward. Additional metrics should also be investigated and monitored as the appropriate subcommittees and working groups continue their review consideration over time. The ERSTF expects to see ongoing enhancements to the Measures and additional recommendations from the other working groups to provide NERC with even greater clarity going forward.

The ERSTF has also developed materials that can be shared with policy makers, regulatory agencies, industry executives, and others to explain the issues and measures. Given the nature of essential reliability services and the significance of such services for energy policy making, system planning, and system operations, NERC should anticipate the need for ongoing information sharing and support for a wide variety of stakeholders. Federal, state, and local jurisdictional policy decisions have a direct influence on changes in the resource mix, and thus can affect the reliability of the BPS. Planning and operations analysis of these emerging changes must be done to ensure continued reliable and economic operation of the BPS.

Summary Table of Recommendations

The ERSTF Measures and Industry Practices are recommended in details below:

Table 1: Summary of Measures and Industry Practices Recommendations

Reference Number	Title	Brief Description	BA or Interconnection Level	ERSTF Recommendation	Ongoing Responsibility
1	Synchronous Inertial Response(SIR) at an Interconnection Level	Measure of kinetic energy at the interconnection level. It provides both a historical and future (3-years-out) view.	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
2	Initial Frequency Deviation Following Largest Contingency	At minimum SIR conditions from Measure 1, determine the frequency deviation within the first 0.5 seconds following the largest contingency (as defined by the Resource Contingency Criteria (RCC) in BAL-003-1 for each interconnection).	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
3	Synchronous Inertial Response at a BA Level	Measure 3 is exactly the same as Measure 1 but performed at the BA level. It provides both a historical and future (3 years out) view and will help a BA identify SIR-related issues as its generation mix changes.	BA	Measure	Resource Subcommittee and Frequency Working Group
4	Frequency Response at Interconnection Level	Measure 4 is a comprehensive set of frequency response measures at all relevant time frames: Point A to C frequency response in MW/0.1 Hz, Point A to B frequency response in MW/0.1 Hz (similar to ALR1-12), C:B Ratio, C:C' Ratio as well as three time-based measures (t_0 to t_C, t_C to $t_{C'}$, t_0 to $t_{C'}$), capturing speed of frequency response and response withdrawal.	Interconnection	Measure	Resource Subcommittee and Frequency Working Group
5	Real Time Inertial Model	Develop a real-time model of inertia including voltage stability limits and transmission overloads as criteria. This is an operator tool for situational awareness and alerts them if the system is nearing a limit and any corrective action is required.	BA	Industry Practice	BA

6	Net Demand Ramping Variability	Measure of net demand ramping variability at the BA level. It provides both a historical and future view.	BA	Measure	Reliability Assessment Subcommittee
7	Reactive Capability on the System	At critical load levels, measure static & dynamic reactive capability per total MW on the transmission system and track load power factor for distribution at low side of transmission buses.	TOP	Measure	Performance Analysis Subcommittee and the System Analysis and Modeling Subcommittee
8	Voltage Performance of the System	Measure to track the number of voltage exceedances that were incurred in real-time operations. This should include both pre-contingency exceedances and post-contingency exceedances. Planners should consider ways to identify critical fault-induced delayed voltage recovery (FIDVR) buses and buses with low short-circuit levels.	No Further Action	No Further Action	No Further Action
9	Overall System Reactive Performance	When an event occurs on the system related to reactive capability and voltage performance, measure to determine if the overall system strength poses a reliability risk. Adequate reactive margin and voltage performance should be evaluated across all horizons (planning, seasonal, real time). This type of post-mortem analysis comports with various requirements in existing and proposed NERC standards.	BA	Industry Practice	Event Analysis Subcommittee
10	System Strength	Based on short circuit contribution considerations, determine if low system strength poses a potential reliability risk. When necessary, calculate short circuit ratios to identify areas that may require monitoring or additional study.	Planning Coordinator	Industry Practice	Planning Coordinator

Detailed Recommendations

The recommendations are fully described in the body of this report and can be summarized as follows:

- Frequency Support Recommendations
  - Calculate the instance of minimal synchronous inertial response (SIR) that occurred in the recent historical study year and its projected value for the next three years (Measure 1 for interconnection and Measure 3 for BAs).
  - At minimum SIR conditions for each of the historical and future years above, determine the frequency deviation that would result within the first 0.5 seconds following the largest contingency of the interconnection (Measure 2 for interconnection).
  - Each interconnection should measure the minimum frequency point (the Nadir) and all aspects of frequency response following observed contingency events (Measure 4).
  - A measure related to situational awareness modeling of available inertia for near-real-time applications when operating the grid (Reference Number 5) was considered. This was identified as an Industry Practice but not recommended as a measure.
- Net Demand Ramping Variability Recommendations
  - Each BA should calculate the historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand ramps (actual load less production from VERs) using one-minute data (Measure 6). Although changes in ramping needs may not indicate a concern, the historical and projected ramp values by BA should be reviewed at both the BA and NERC level to allow for early identification of potential areas for further analysis.
- Voltage Support Recommendations
  - Measures of reactive capability should be calculated and tracked by the appropriate registered entity, including both static and dynamic reserve capability per total megawatt load at peak, shoulder, and light load levels; and load power factor for distribution at the low side of transmission buses at peak, shoulder, and light load levels (Measure 7).
  - The ERSTF considered, but does not recommend, potential measures of voltage performance for tracking voltage exceedances during real-time operations and monitoring buses with low short-circuit strength or susceptibility to fault-induced delayed voltage recovery (FIDVR) conditions (Reference Number 8).
  - The ERSTF discussed a potential measure for reviewing system events that suggest stressed reactive capability or degraded voltage profiles to compare planned performance with real-time operations and evaluate voltage performance (Reference Number 9). This was identified as an Industry Practice but not recommended as a Measure.
  - The appropriate registered entity should measure system strength based on calculating short circuit ratios for sub-areas in the system (Reference Number 10). This was identified as an Industry Practice but not recommended as a Measure.

Frequency Support

Frequency support is the response of generators and loads to maintain the system frequency in the event of a contingency. For the ERSTF's purposes, the frequency support response generally consists of a combination of immediate inertial response, fast frequency response,[1] primary frequency response, and some slow responses to supplement the resources that have responded more quickly.

The task force recommends Measures to track the minimum frequency and frequency response following the observed contingency events, track and project the levels of conventional synchronous inertia in the arresting time frame for each balancing area and the interconnection, and track and project the initial frequency deviation in the first half-second following the largest contingency event for each interconnection. We will look at each of these in turn, focusing first on the Measures of conventional synchronous inertial response, then looking at the system's overall response to a frequency event in the Frequency Response section that follows.

Synchronous Inertial Response Measures

Rotating turbine generators and motors that are synchronously connected to the system store kinetic energy that, during contingency events, is released to the system (also called inertial response). Inertial response provides an important contribution to reliability in the initial moments following a generation or load trip event: determining the rate of change of frequency. In response to a sudden loss of generation, kinetic energy will automatically be extracted from the rotating synchronized machines on the interconnection, causing the machines to slow down and frequency to decline. The amount of inertia depends on the number and size of generators and motors synchronized to the system, and it determines the rate of frequency decline. Greater inertia reduces the rate of change of frequency, giving more time for primary frequency response to fully deploy and arrest frequency decay above under-frequency load shed set points.

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

Interconnections with growing amounts of nonsynchronous generation or electrically de-coupled resources should project future SIR trends based on historical SIR information and planned projects in the interconnection queue (e.g., signed interconnection agreements and financial commitments for nonsynchronous generation). These projections will help BAs anticipate decreasing interconnection SIR conditions, which will increase the challenges associated with meeting the interconnection frequency response obligations (IFROs) to preserve reliability.[2] The ability to anticipate the changes in SIR will help BAs develop approaches to offset any decline in SIR to meet their IFRO as required in BAL-003-1.

For systems in which the amount of SIR is decreasing, there are various ways to compensate and maintain reliability, potentially including fast frequency response resources. In some cases, retiring synchronous generators could be converted to synchronous condensers that provide inertia and reactive support, and maintain system stability. During the planning of the BPS, understanding how changes in SIR interact with primary frequency response and locational aspects will be crucial to preserve reliability and determine if a minimum SIR requirement is necessary.

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[1] Fast frequency response is high-speed energy contribution such as that from controlled load, storage, synthetic inertia from wind, or other sources.

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

Measure 1: Synchronous Inertial Response at an Interconnection Level

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

1. For every hour in a year, determine the total available inertial response from all on-line synchronous generators in the interconnection (see boxplots, Figure 1). Identify the instances and conditions that resulted in the minimum inertial response in a year. If an hourly sampling of inertial data for an entire year is not available, then use several historical snapshots that are likely to have yielded low system inertia conditions.
2. Project the minimum inertial response in future years (the next three years). See points corresponding to this response, Figure 1.

Measure 2: Initial Frequency Deviation Following Largest Contingency

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

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

Data Requirements for Interconnection Level Measures 1 and 2

- Historical: generator on-line/off-line status, inertia constant (H) for every synchronous generator, MVA rating for every synchronous generator in the interconnection.
- Future: anticipated nonsynchronous generation in a future year, based on planned projects with signed generation interconnection agreements (GIA) and financial commitments in each BA area of an interconnection.
- Measures 1 and 3 are the same, with Measure 1 at the interconnection level and Measure 3 at the BA level. For the figures shown below, note that ERCOT acts as both the BA and interconnection.

Note on Boxplots

On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, the whiskers correspond to +/- 2.7 sigma (i.e., represent 99.3% coverage, assuming the data are normally distributed), and the outliers are plotted individually (red crosses). If necessary, the whiskers can be adjusted to show a different coverage.

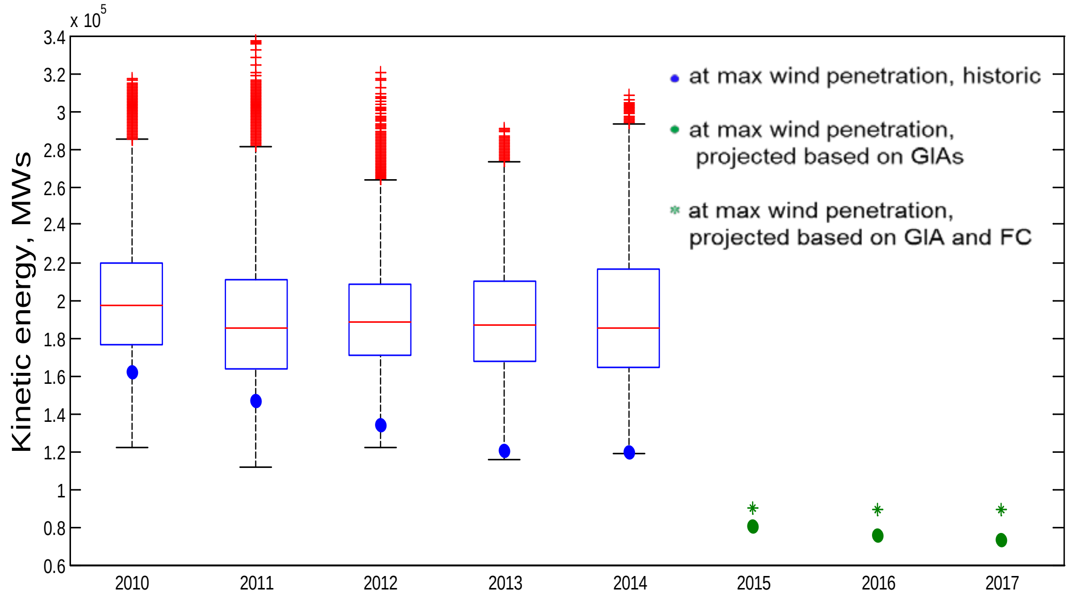


Figure 1: ERCOT historic kinetic energy boxplots (2010–2017)[3]

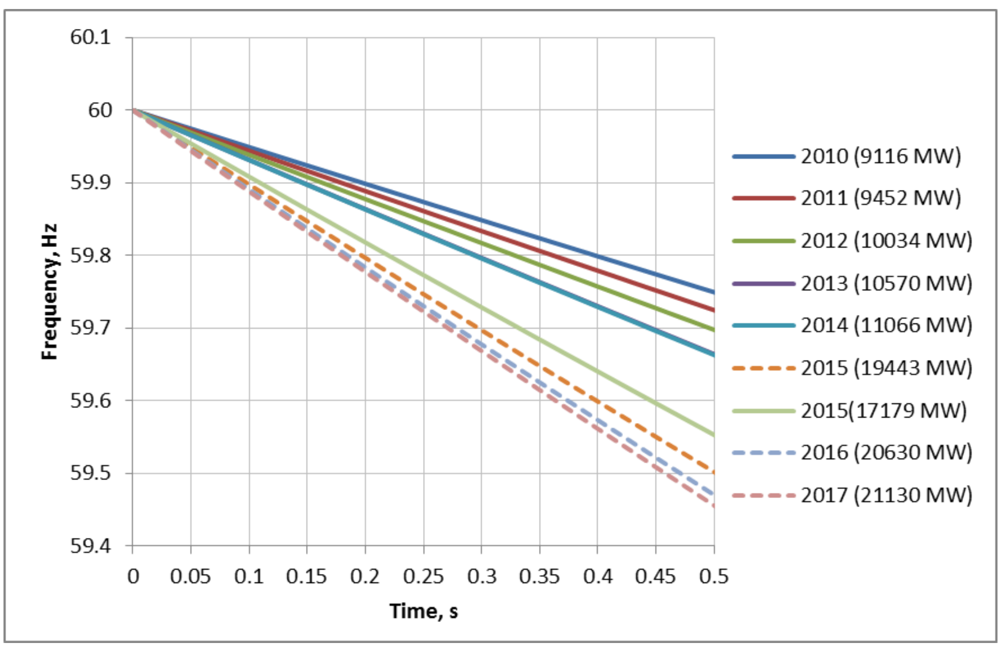


Figure 2: Calculated ERCOT system frequency after 2750 MW generation trip (2010–2017)

[3] On the Figure 1 legend, GIA stands for signed generation interconnection agreements, and FC stands for financial commitments.

Measure 3: Synchronous Inertial Response at BA Level

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

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

Data Requirements for BA Level Measure 3

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

Detailed calculation procedures for Measures 1, 2, and 3 are provided in the Frequency Response appendix.

Summary of Analysis

Selected BAs, WECC, and NERC (for Eastern Interconnection) were requested to submit Measures 1, 2, and 3 for years 2011–2014 along with a three-year projection for years 2015–2017. For Measure 2, projections for years 2015–2017 were based on data gathered for Measure 1. Detail for WECC and each BA that submitted data is available in Appendix A.

Measures 1 & 2

In WECC and the Eastern Interconnection (EI) it was difficult to obtain the data necessary for Measures 1 and 2. In WECC, while the unit status is available from the Peak Reliability State Estimator (West-wide System Model - WSM), the WSM cases were only available for specific snapshots in time. It was also difficult to map generators from WSM cases with corresponding inertia constants.

For EI, dynamic models are available to NERC, and information may also be available on generator unit status from the Parallel Flow Visualization (PFV) project. In addition, the NERC Resources Subcommittee (RS) recently conducted a generator governor survey that requested the generator inertia constant for each machine. That data can be used to calculate Measures 1 and 2 for EI. Mapping between unit names in the generator governor survey and PFV will also be a challenge that will need to be addressed. It was concluded that there appears to be no immediate urgency to calculate Measures 1 and 2 in EI; however, there is a need to begin collecting the data in order to analyze and trend these Measures over time. Overall, generator operators are required under NERC Reliability Standards MOD-012, -026, and -027 to provide machine data to their Planning Coordinators and Transmission Operators; therefore, generator inertia constant data should be available. The main challenge will be mapping of generator parameters with respective generator status from state estimator models.

While it is currently difficult to analyze Measures 1 and 2 at the interconnection level, these Measures, along with Measure 4,[4] will aid in the understanding of the causes of the declining frequency nadir during generator trip events. This understanding will allow the discovery of the most effective solutions to address declining frequency nadir as the generation resource mix continues to change. For example, frequency nadir after a generator trip

[4] Measure 4 - a comprehensive set of frequency response measures at all relevant time frames, discussed further in the report.

may be low because system inertia is too low. Consequently, the rate of change of frequency is too high, and/or there is no fast frequency response available (or the fast frequency response that is available is not sufficiently fast). Frequency nadir may also be low because there is not enough generation with governor response, or generation with fast governor response has been replaced with slower resources, etc. Depending on the cause of low-frequency nadir, the most effective measures to address the issue may vary.

Measure 3

The responses from nine BAs were received and analyzed. A high-level summary is provided in Table 2, and additional supporting details are included in Appendix A. Overall, the BAs found this exercise insightful. While the initial data-gathering effort was challenging, identifying the sources of information will facilitate an easier tracking of Measure 3 in the future. MISO and ERCOT have also set up real-time synchronous inertia calculators to allow for easier tracking of Measure 3.

Table 2: Summary Data for Measure 3

BA/ISO	Installed capacity of nonsynchronous generation (NSG), 2014	2014, nonsynchronous generation penetration peak, in % of load at the time	Installed capacity of nonsynchronous generation 2017	2017, nonsynchronous generation penetration peak, in % of load at the time	Inertia trending down?
ERCOT	11,066	39%	21,130	75%	Yes
ISO NE	3,155*	10%	5,591*	23%	Yes
IESO	4,075*	16%	5,607*	22%	Somewhat
MISO	13,726	16%	18,526	21%	Somewhat
BC Hydro	487.2	13%	667	12%	No (too little NSG)
Southern BA	454	1%	2,324	2%	No (too little NSG)
Duke: DEF	0	0%	0	0%	No (no NSG)
Duke: DEC	136	not significant	232	not significant	No (too little NSG)
Duke: DEP	320	not significant	712	not significant	No (too little NSG)

*Includes HVDC import capacity and renewables (for the areas that import during non-synchronous generation peaks). In 2017, increase in installed capacity of NSG is caused by increase in renewable generation; no HVDC tie capacity increase.

Note that Table 2 shows installed nonsynchronous generation capacity in 2014 and 2017 for the respondents as well as peak of nonsynchronous generation penetration defined as:

$$\max_{t\in[1:8760]} \frac{P_{NSG}(t)}{P_{load}(t)} \cdot 100\%$$

Where $P_{NSG}(t)$ is power production from nonsynchronous generation resources in hour *t* (including imports over HVDC ties), $P_{load}(t)$ is BA load in hour *t.*

Based on experience with wind generation in the ERCOT system, nonsynchronous generation displaces conventional synchronous generation on-line that provides synchronous inertia. In ERCOT, periods with high power production from nonsynchronous generation coincide with low load periods; therefore, the hour of maximum nonsynchronous generation penetration corresponds to the hour with minimum synchronous inertia in a year. However, this conclusion does not necessarily apply to other areas. Analyzing the results from different BAs, it became apparent that the results depend on:

- type of nonsynchronous generation,
- time periods when power production from nonsynchronous generation is high, and
- presence of must-run synchronous generation on a system.

Another indicator may be needed to identify minimum synchronous inertia hour in each year. The proposed indicator for the future projections of a minimum of Measure 1 and 3 is an hour of:

$$\max_{t\in[1\ \ 8760]} \frac{P_{NSG}(t)}{\sum_i MVA_{SG\_i}(t)} \cdot 100\%$$

Where $\sum_i MVA_{SG\_i}(t)$ is a sum of MVA ratings of all on-line synchronous generation resources in hour *t.*

Recommendations

- Measures 1, 2, and 3 should be analyzed once a year along with a three-year projection.
- The task force recommends that values be calculated by the appropriate entity (see Table 1) for trending and analysis by the Resource Subcommittee and Frequency Working Group.
- Measures 1 and 3 should be analyzed on an hourly basis (8760 hours per year). However, if a comprehensive yearly data set is not available, another acceptable method would be to use historical snapshots of hours with low load/high nonsynchronous generation (i.e., low synchronous inertia) provided these snapshots capture minimum inertia.
- Related to Measure 3, a BA's synchronous inertial response will change with a changing resource mix. While BAs normally rely on neighboring BAs for inertial response, the tracking of Measures 2 and 3 is important for potential islanding scenarios.
- Eastern Interconnection (EI) – While there appears to be no immediate need to track Measures 1 and 2 at the interconnection level due to lower penetration levels of nonsynchronous generation at this time, there is a need to begin developing data collection methods necessary for Measures 1 and 2 at the interconnection level and developing the capability of tracking these Measures. Once these Measures are tracked on an interconnection basis, a benchmark related to inertia requirements can be established for future years.
- ERCOT – ERCOT should continue to track Measures 1 and 2 due to high renewable penetration.

- WECC – While the data is available for Measures 1 and 2, mapping between generator inertia constants and generator on-line status information is not available. A process needs to be established to map the inertia constants and on-line status of generators.

Observations

- For Measure 3, it would be a good practice to set up a real-time inertia calculation that will simplify the retrieval of synchronous inertial response data for future analysis.
- For Measure 2, it would be beneficial to capture load damping if this information is available. Without inclusion of the load-damping information, Measure 2 may show a somewhat higher frequency deviation than what may actually be occurring.
- It would also be prudent to:
  - produce a common reporting method for BAs and interconnections to simplify data aggregation and trending;
  - clarify the terminology for data fields in data requests; and
  - identify the responsible groups for data collection and data review going forward.

Frequency Response Measures

Frequency response is the traditional metric used to describe how an interconnection has performed in arresting decline and stabilizing frequency after the loss of resources or load. Figures 3 and 4 use two frequency excursion events—one in the Western Interconnection and one in the Eastern Interconnection—to demonstrate the relevant points and values associated with calculating the Frequency Response Measure and for developing trending metrics for frequency response moving forward. Primary frequency response is measured by relating the size of the resource lost to the resulting net change in system frequency. The period in which stabilizing frequency is determined is defined as the time from t_0+20 to t_0+52 seconds following the initiating event (t_0). (See the explanation of the NERC ALR1-12 metric in the text box below).

The conventional definition of primary frequency response is based on stabilizing frequency (Value B) driven by the fact that performance evaluation has been limited to the BA level. BAs have traditionally only had 2- to 6-second scan-rate data available from their supervisory control and data acquisition (SCADA) systems for frequency and interchange measurements. That fact still governs the periodicity of measurement used for frequency response calculations in NERC Standard BAL-003 where the measurements are evaluated at the BA level.

However, recent advancements in higher-resolution synchronized measurement technology on the power system have unlocked capabilities for examining primary frequency response at the interconnection level and at scan rates much faster than conventional SCADA systems. Therefore, the proposal for Measure 4 on frequency response is based on sub-second resolution measurements from phasor measurement units (PMUs) and frequency disturbance recorders (FDRs). These devices record frequency at rates of 10 to 60 samples per second, affording the capability for far greater fidelity when measuring the frequency nadir, which has always been described as an instantaneous value.

Interconnection-level primary frequency response performance is judged against the Interconnection Frequency Response Obligation (IFRO), which is annually calculated to ensure that frequency excursions caused by loss of large-scale resources do not result in tripping of load by under-frequency load shedding (UFLS) systems. Those systems are designed as a backstop to prevent such events from cascading across the BPS. Primary frequency controls are deemed adequate if, following the sudden loss of largest generation,[5] primary frequency control actions provided by on-line resources successfully arrest and stabilize frequency decline prior to dropping firm customer loads through the UFLS programs. If the frequency nadir(s) (Point C or C') is greater than the highest set point for UFLS, then the primary frequency response sufficiently arrested and stabilized frequency. Otherwise, if frequency falls below the UFLS set points, firm customer loads will be dropped as a precaution to further attempt to arrest frequency decline.

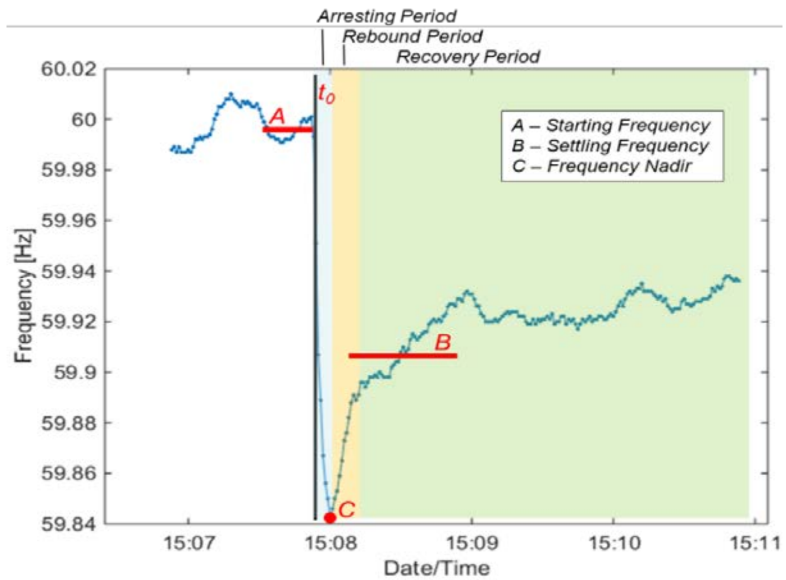


Figure 3. Frequency response example for large disturbance in Western Interconnection

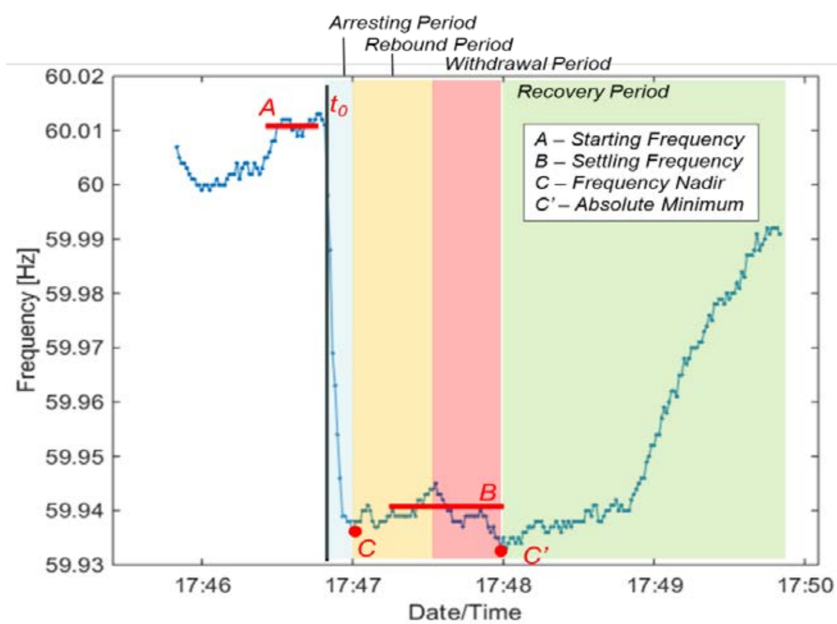


Figure 4. Frequency response example for large disturbance in Eastern Interconnection (with governor withdrawal)

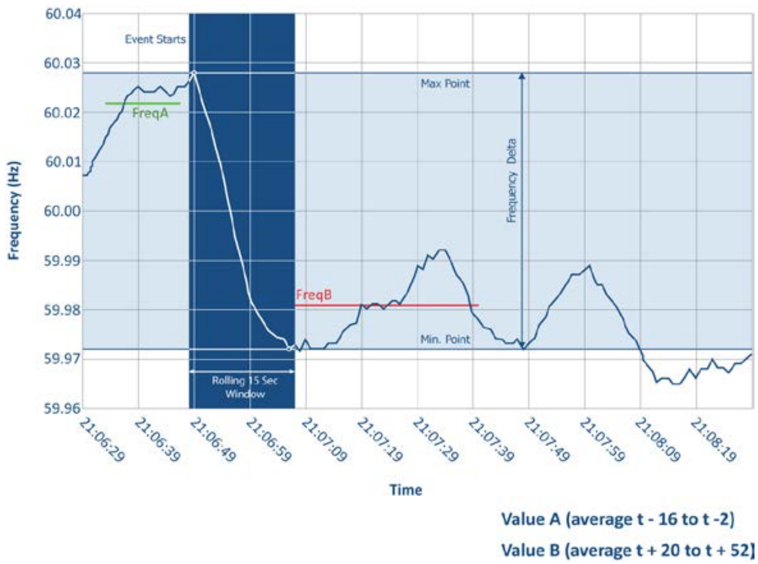
[5] Largest generation loss is defined as largest category C (N-2) event except for Eastern Interconnection, which uses largest event in the last 10 years.

ALR1-12:

This metric is used to track and monitor interconnection frequency response. It is defined as the sum of the change in demand plus the change in generation divided by the change in frequency, expressed in MW/0.1 Hz. The metric measures the average frequency response where frequency drops more than the interconnection's defined threshold (table below). High-resolution frequency measurements from the University of Tennessee, Knoxville (UTK) FNET system are down-sampled to produce 1-second resolution time series data, which is used in ALR1-12 analysis[6].

While the calculations may show trends from year to year, no attempt has been made in this analysis to determine or state what indicates the "acceptable" level of frequency response. Rather, they show the relative performance from year to year and can be a basis for future root-cause analysis.

The figure 5 below shows the criteria for calculating average values A and B; the event starts at time t0. Value A is the average frequency from t0-16 to t0-2 and Value B is the average frequency from t0+20 to t0+52. The difference between A and B is the change in frequency used for calculating frequency response for ALR1-12. The time windows used for calculating these values account for variability in SCADA scan rates, ranging from 2 to 6 seconds between BAs.



Interconnection	ΔFrequency (mHz)	MW Loss Threshold	Rolling Windows (seconds)
Eastern	36	800	15
Western	70	700	15
ERCOT	90	450	15
Quebec	140	450	15

Figure 5. Frequency response example for large disturbance in Eastern Interconnection

[6] See http://www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx.

Measure 4: Frequency Response

The following Measures focus on **all** aspects of frequency response and should be trended at the interconnection level to enhance the traditional frequency response metric (ALR1-12). The task force recommends that values be calculated by the appropriate entity on a regular basis and tracked by the Resource Subcommittee and Frequency Working Group. The various components include:

1. **A to B frequency response** captures the effectiveness of primary frequency response in stabilizing frequency following a large frequency excursion. This Measure is the conventional means of calculating frequency response as the ratio of net MW lost to the difference between Point A and Point B.

$$Frequency\ Response_{Current} = \frac{Generation\ Lost\ (MW)}{Frequency_A - Frequency_B}$$

   Trending ALR1-12 in MW/0.1 Hz year to year versus trending only system conditions will provide additional insights concerning primary frequency response levels and characteristics. ALR1-12 metric is already being used. However, trending it versus time does not provide information on how at similar system conditions the response is changing year to year.

2. **A to C frequency response** captures the impacts of inertial response, load response (load damping) and initial governor response (governor response is triggered immediately after frequency falls outside of a pre-set deadband; however, depending on generator technology, full governor response may require up to 30 seconds to be fully deployed). This Measure is calculated as the ratio of net megawatt lost to difference between Point A and Point C frequency.

$$Frequency\ Response_{Nadir} = \frac{Generation\ Lost\ (MW)}{Frequency_A - Frequency_C}$$

   Trending this Measure year to year will capture effects of changes in generation mix and load characteristics and help identify needs for synchronous inertia and/or some forms of fast frequency response (e.g., from battery storage or load resources with under-frequency relays).

3. **C to B ratio** captures the difference between maximum frequency deviation and settling frequency. The C to B ratio is related to governor responsiveness with respect to frequency deviation reading, and its their capability to arrest and stabilize system frequency.

$$C\colon B\ Ratio = \frac{Frequency_C - Frequency_A}{Frequency_B - Frequency_A}$$

   This Measure should also be trended year to year versus trending only system conditions to provide insight into the amount of generation providing primary frequency response compared with the total committed generation on-line.

4. **C’ to C ratio** is the ratio between the absolute frequency minimum (Point C’[7]) caused by governor withdrawal and the initial frequency nadir (Point C).

$$C'\colon C\ Ratio = \frac{Frequency_{C'} - Frequency_A}{Frequency_C - Frequency_A}$$

[7] Point C’ is observed in the Eastern Interconnection following frequency excursions due to large generator trips. Following initial governor response to deviation from set point frequency, generating units’ active power set point control takes over, bringing the unit back to its original operating point. This results in withdrawal of the initial governor response and a consequent decline in frequency due to the decline in injected real power into the system.

In the Eastern Interconnection, the difference between Point C and Point C' is of concern due to governor response withdrawal. While ALR1-12 data does not contain C', original frequency data with 1-second resolution (which captures 300 seconds of an event) can be used. In the Eastern Interconnection, trending the difference between Point C and Point C' for similar-sized events will capture whether Generator Owners are working with vendors to adjust plant Distributed Control Systems load controllers to mitigate the impact of governor response withdrawals.[8]

5. **Time-based Measures** are used to capture the speed in which inertial and primary frequency response as well as governor withdrawal are occurring. These Measures can be trended year to year to identify trends in the rate of change of frequency decline and whether the governor withdrawal phenomena are trending toward improvement or further degradation. These Measures include:

   a. **t_C-t_0 Measure** is the difference in time between the frequency nadir and initial event. It captures the time in which system inertia and governor response arrest declining frequency to its minimum level. Trending this time difference can be useful for ensuring that the defined times for BAL-003-1 fit the actual event data. In addition, trending this with respect to event size and initial frequency can help identify how deadband settings play a role in frequency arrest.

   b. **$t_{C'}$-t_C Measure** is the difference in time between the governor withdrawal minimum and the initial frequency nadir. This Measure captures the time in which governor stabilization and withdrawal occur prior to secondary controls and load responsiveness beginning to return frequency to its initial value.

   c. **$t_{C'}$-t_0 Measure** is the difference in time between the governor withdrawal minimum and the initial event. This provides a comprehensive picture of the overall time in which frequency declines and continues to fall due to the initiating event. While C' should be mitigated and eliminated entirely, the time between the initial event and absolute minimum should also be minimized. In the Eastern Interconnection, it is observed that the minimum frequency level (C' value) due to governor response withdrawal generally occurs 59–78 seconds after an event.

Examples of the proposed frequency response Measures are provided in Appendix A. It should be noted that historical trending of frequency response does not show aggressively degrading frequency response in any of the four interconnections. Efforts related to BAL-003-1 and surveying the Generator Owners regarding governor set point controls have proved effective in communicating the need for primary frequency response. The Measures outlined herein should be tracked for each interconnection such that frequency response can continue to be metricized year to year. If concerns arise and a notable decline in frequency response is observed, then NERC will explore root causes of the declining trends and appropriate action can be taken.

Measure 5: Real-Time Inertial Model

The task force reviewed the development of a real-time model of inertia. As implemented by CAISO, this can include inertia as well as voltage stability limits and transmission overloads as criteria in the model. In CAISO and ERCOT, this type of tool is intended to be an operator tool for situational awareness and alerts them if the system is nearing a limit. The task force decided not to pursue real-time inertia as a measure but, as appropriate, it could be developed and used by a BA as an Industry Practice for those experiencing a decline in system inertia.

[8] The proposed control algorithm to avoid governor response withdrawal was presented during the NERC Frequency Response Initiative webinar on April 7, 2015.

Net Demand Ramping Variability

Changes in net demand require BAs to rely on generators, loads, or other system load-following capabilities. BAs with high penetrations of nondispatchable resources[9] and/or variable energy resources (VERs) may need faster system ramping capability to follow changes in net demand. For example, Figure 6 shows the actual wind (green curve) and solar (yellow curve) production variability experienced by CAISO on March 1, 2014, and Figure 7 shows the actual load (blue curve) and net demand (red curve) for the same day. As shown, the multi-hour ramp during the evening hours partly coincides with sunset. In addition to meeting the increase in load, CAISO must ensure that enough system ramping capability is available to follow the changes in solar and wind production. As BAs integrate more nondispatchable resources and/or VERs into their resource mixes, the need for system ramping capability may increase to ensure compliance with real-time control performance standards. On the other hand, BAs where most VERs and conventional resources are dispatched and responsive to system operator commands may find that they have sufficient flexibility even with growing VER penetrations.

ERSTF analysis found that ramping capability is not currently a challenge for most BAs, but CAISO, with a significant amount of VERs, nondispatchable generation, and base-loaded generation, has found this to be a challenge. CAISO has found that it may not be able to commit more dispatchable resources due to the risk of overgeneration on low demand days, such as on weekends or holidays. It is important to emphasize that the issue is not ramping alone, but the combination of increased ramp rates and limited control of nondispatchable resources and VERs by the system operator.

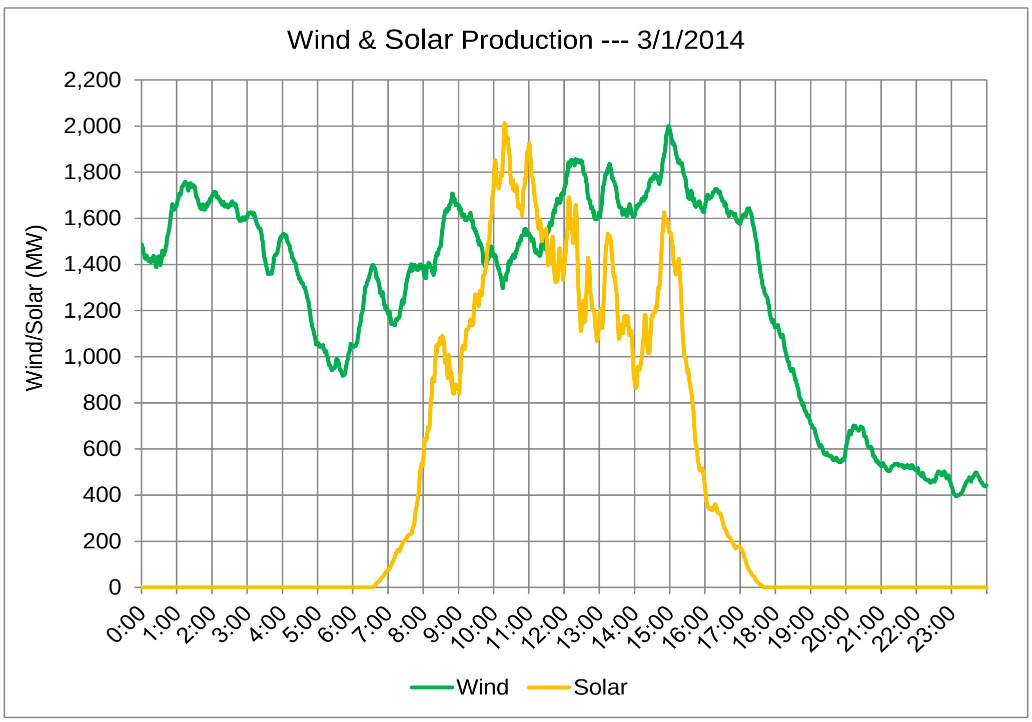


Figure 6: Wind and solar production in CAISO

[9] Nondispatchable generation includes resources for which the BA does not have dispatch authority due physical, regulatory, tariff or contractual reasons, or does not tend to respond to price or dispatch instructions.

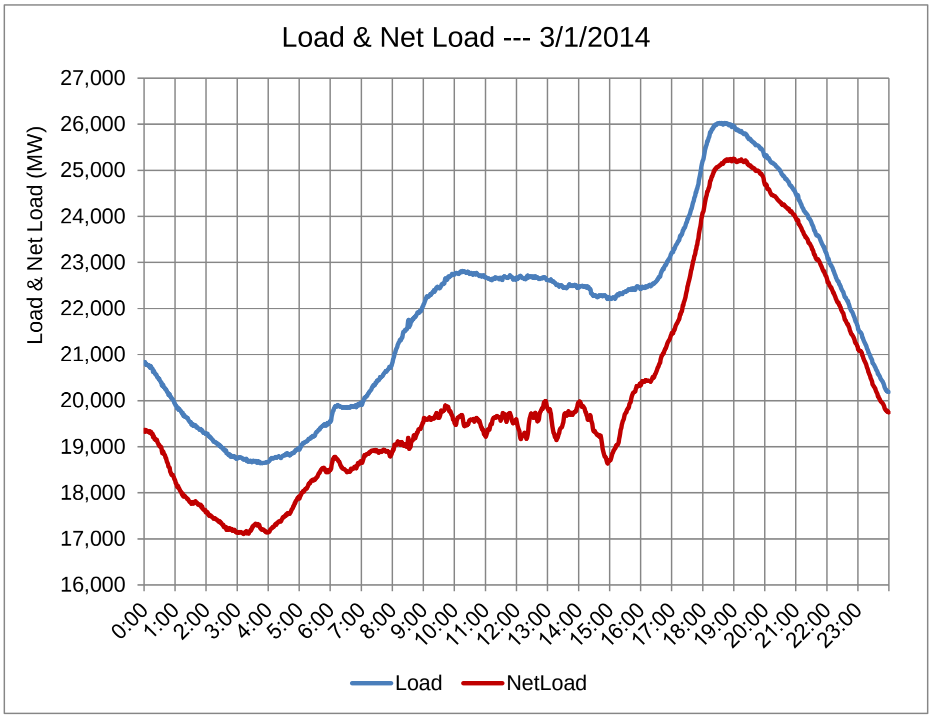


Figure 7: Load and net demand

Measure 6: Net Demand Ramping Variability

This is a measure of net demand ramping variability[10] at the BA level. It provides both a historical and future view of the maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net variability. The net variability is generally calculated as the difference between total load and production from VERs, although other variable loads and generation types may be included. This analysis should be done for the current study year, three recent historical years, and a projected year four years in the future (e.g., the 2014 study year would include 2011–2013 historical years and the 2018 future year).

Data Requirements

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

Appendix B describes the data, approaches, and details for building the future VER portfolio, including the build-out of load, wind, and solar profile, as well as defining the BA's ramping needs. Examples are provided to show how this is currently being done for both ERCOT and CAISO.

[10] CAISO defines "net demand" as load minus all VER generation, although other variable loads and generation types may be appropriately included depending on their operating characteristics.

Summary of Analysis

Measure 6 outlines a method to evaluate the net demand ramping variability at the BA level. As more resources that exhibit fluctuations in output (such as VERs) are integrated into a BA's resource mix, the BA may be faced with increases or decreases in the amount of demand or generation at certain times during the operating day. This measure provides both a historical and future view of the maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand variability. A BA expecting an influx of VERs may elect to evaluate variability at different time frames depending on its existing generation mix and/or its scheduling timeline. Ultimately, the BA needs to have adequate resources available to meet the expected demand variability (i.e., the necessary ramping capability).

A recent NERC survey of selected BAs requested historical data as well as expected VERs build-out through 2017. The results of the survey were used to analyze the net demand variability of the three recent historical years and four years in the future. Of the 10 BAs surveyed, only CAISO identified a significant increase in net demand variability or an increased need for flexible capacity in the near-term future years.

For CAISO, this increase in variability is expected to occur during the spring months within the three-hour period prior to the evening demand peaks, which also coincides with the drop-off of production of grid-connected solar resources and rooftop-distributed solar PV. These large three-hour ramps may or may not create operational issues for other BAs depending on the time of their peak demand, amount of nondispatchable resources, and amount of flexible resources within their existing resource mix. The nondispatchable resources within CAISO's existing resource mix are in excess of 10,000 MW (including geothermal, biomass, biogas, and small hydro that count toward California's renewable portfolio standard). When combined with other contractually nondispatchable resources and nuclear resources, nondispatchable conventional resources can exceed 50 percent of supply on low demand days such as weekends. During normal operating conditions, these nondispatchable resources are base loaded and, largely due to contractual rather than physical reasons, can only be curtailed for reliability concerns.

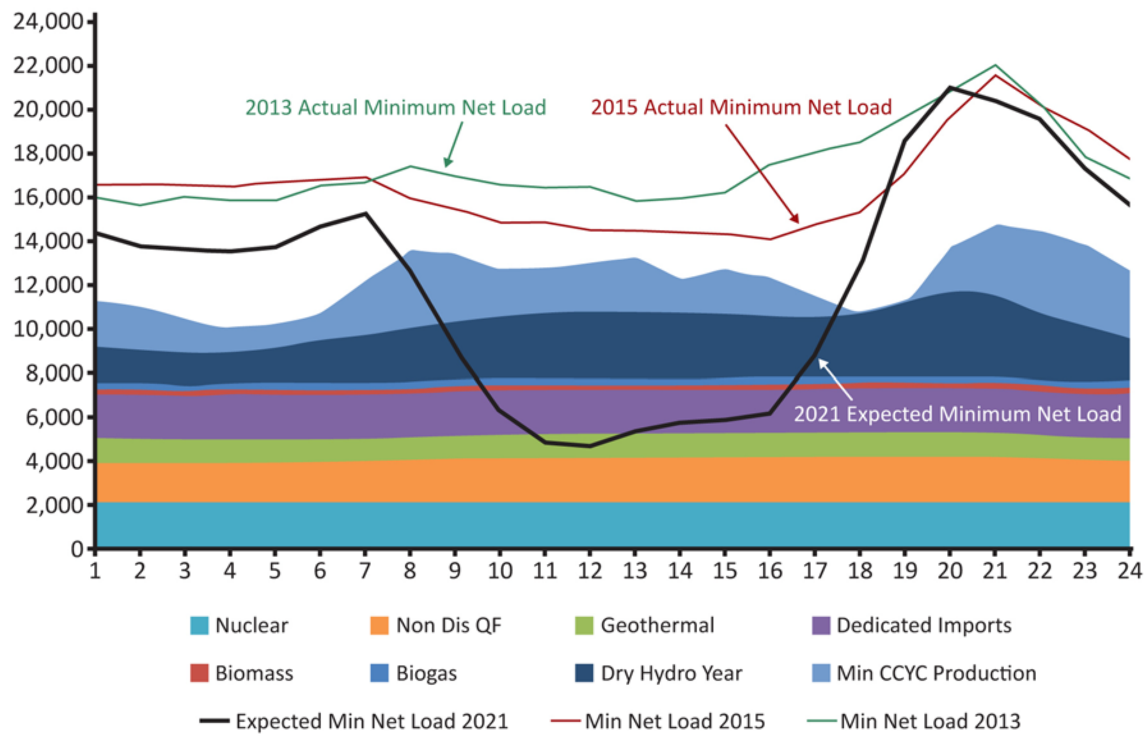


Figure 8: Expected minimum on-line resources in typical spring months, 2021

Recommendations

The ERSTF recommends that Measure 6 be monitored and evaluated at the BA level and the data provided to NERC annually for industrywide trending and analysis by the Reliability Assessment Subcommittee.

Additional considerations for BAs that have or expect to have a high penetration of wind, solar, and nondispatchable resources. BA may choose to:

- Track net demand variability on an annual basis. It is also important to note that rooftop solar PV is netted from demand, so trending of net demand variability may show an increase in variability as more rooftop solar PV is installed.
- Trend their control performance standard 1 (CPS1, see Appendix C) scores on shortened time frames, such as hourly or daily, to identify any correlation between significant intrahour or multihour ramps and CPS1 excursions below 100 percent across the same time frame.
- Begin tracking the frequency and duration when their Balancing Authority ACE Limit (BAAL, see Appendix C) exceeds predefined limits and identify any correlation when these limits are exceeded and insufficient ramping capability exists in the committed fleet.
- Review their net inadvertent interchange to determine if ramping deficiencies within a BA result in inadvertent flows to neighboring entities during ramp deficiencies.
- Develop day-ahead and real-time forecasting tools to better predict VER output changes.

Observations

CAISO, which has high penetration levels of both VERs and nondispatchable resources, provided the following observations:

- Greater risk of overgeneration during periods of low demand because some resources cannot be shut down due to long start-up times or contractual limits.
- Need to mitigate steep intrahour net demand ramps and multihour net demand ramps.
- Need for more flexible resources with ramping capability.
- Need for resources to have the capability to stop and start multiple times per day.
- Greater difficulty in accurately forecasting operating needs of the system.
- Potential for rapid change in the intrahour ramp direction.
- Any nondispatchable resources can exacerbate minimum-generation concerns.

Based on the experience within CAISO, BAs and TOPs with high penetrations of VERs and nondispatchable resources should account for the characteristics of those resources when monitoring and evaluating generation resources included in their unit commitment process or when procuring resources.

Voltage Support

The ability to control the production and absorption of reactive power for the purposes of maintaining desired voltages is critical to the reliable and efficient operation of the power system. Unlike frequency response, which primarily pertains to large regions, voltage issues tend to be local and generally require responses from generators at the appropriate locations or remedial actions such as the installation of static or dynamic reactive resources, addition of series compensation, use of reliability out-of-merit resources, etc. To assess the strength of the system, and to some degree the overall reliability of the system, the industry should consider tracking specific Measures related to voltage support. The Measures can be used to assess the strength of reactive support and to quantify trends that may result from the changing resource mix of both generation and load.

Regional differences may require some flexibility or customization of the Measures. Systems vary widely in their topology and electrical characteristics (e.g., the total level of installed reactive resources, the type of reactive resources, applicable local and regional voltage criteria, etc.). In general, Measures may align with the BA or TOP construct under the NERC functional model, but because of the localized nature of reactive capability, more useful insights should be gained by developing and monitoring the Measures by sub-areas within the BA footprint. Sub-area definitions generally consider system characteristics such as:

- reactive performance within the footprint,
- real power import, export, and flow-through characteristics,
- transmission topology and typical constraints (e.g., surge impedance loading),
- charging from cables or long overhead lines,
- types of resources (i.e., synchronous and/or nonsynchronous/inverter based),
- existing reactive resources (shunt capacitors/inductors, SVCs, STATCOMs, DVARS, generators, HVDC terminals, series compensation, etc.), and
- real and reactive load distribution.

Reactive Power and Sub-Areas:
It is a characteristic of the BPS that reactive power cannot be transmitted long distances. The availability and type of reactive resources also impacts the voltage profile and ability to recover after a contingency. For this reason, planners should consider defining sub-areas or clusters within their footprints that have similar voltage and reactive characteristics. As an example, an urban area that has limited reactive resources relative to its load and must import large amounts of real power may be an appropriate sub-area to analyze. A large rural area with weak transmission, limited load, and significant economic real power resources that are exported may also be an appropriate sub-area to analyze. NERC has produced a whitepaper on this topic. For further information, please reference the *Reactive Support and Control White Paper* developed by the Transmission Issues Subcommittee - Reactive Support and Control Sub-team (May 18, 2009).

Measure 7: Reactive Capability on the System

This Measure tracks static and dynamic reserve capability per total megawatt load at peak, shoulder, and light load levels; and load power factor for distribution at the low side of transmission buses at peak, shoulder, and light load levels. A data request was developed asking for the information on a BA basis for equipment on or connected to the transmission system at 100 kV and above. The measure also offered BAs the option of providing the data by reactive sub-areas if available. The request sought data for the past five years and the current year plus four future years. Several BAs responded to the request.

Observations

Based on the review of the data provided by the participating BAs, it appears that most entities have significant amounts of both dynamic and static reactive margin while maintaining load power factors above 90 percent. There were no cases that showed significant deviations in the year-to-year trends. A few entities did appear to have slightly tighter margins than others; however, these were not considered a significant concern. Review of the data does suggest the value of ongoing monitoring of this Measure.

Recommendations

The results from the data requested in Measure 7 provided insight into the potential reactive strength of the system. It does appear that data provided by individual BAs may impart much more insightful trends if reported on a sub-area basis due to the localized nature of voltage and reactive issues. Entities should consider developing and using a definition of appropriate sub-areas within their footprints to get a clearer picture of system reactive robustness. In order to monitor the continued reactive health of their respective systems, BAs should continue to trend these quantities on an ongoing basis preferably by sub-area to look for new trends and to promote the optimization of dynamic, static, and reactive load. The Measures should be reported and trended based on requirements to be specified by the Performance Analysis Subcommittee and the System Analysis and Modeling Subcommittee.

Measure 8: Voltage Performance of the System

This potential measure would track the number of voltage limit exceedances occurring in real-time operations based on established BA-level voltage criteria (including voltage exceedances during real-time operations) and monitor buses with low short-circuit strength or susceptibility to fault-induced delayed voltage recovery (FIDVR) conditions.

Recommendations

After discussion, the ERSTF decided that there was significant overlap with Measure 9 and no need to pursue this potential measure on a standalone basis.

Measure 9: Overall System Performance

This potential measure would look at events related to a system's reactive capability and voltage performance to identify if the overall system reactive strength poses a risk to reliability. When an event occurs on the system related to reactive capability and voltage performance, this type of event will most likely fall under the NERC Event Analysis Process. The ERSTF proposed that after this type of event, the reactive margin and voltage performance should be evaluated across all horizons (planning, seasonal, real time). This comparison will provide useful insight into the success of the planning process in designing a robust system, document that the as-built system conforms to the requirements specified in the planning studies, and confirm the ability of Operations to effectively manage those resources in real time. A post-mortem analysis of this nature comports with various requirements in existing and proposed NERC standards.

Recommendations

The ERSTF concluded that this should be considered an Industry Practice, but not a formal Measure that should be tracked at NERC. Because these types of events will fall under the NERC Event Analysis Process, they will still be subject to those reporting requirements. Further analysis and trending would then be undertaken by the Event Analysis Subcommittee.

Measure 10: System Voltage and Reactive Strength Performance

The new TPL-001-4 standard requires the Transmission Planner and the Planning Coordinator to conduct annual assessments of the short circuit capability of the system for the purpose of circuit breaker fault duty analysis. The short circuit data from this assessment can be used to calculate the short circuit ratio (SCR) at buses as defined in IEEE Standard 519-2014. The SCRs can be used as a gauge for identifying areas that may potentially have reliability risks associated with FIDVR-type events and other related voltage stability phenomena. Once low-SCR areas are identified (typically using SCR less than three), entities can utilize traditional study techniques to further analyze the potential for FIDVR and voltage stability issues.

This potential measure is applicable in areas where there is a significant amount of inverter-based resources or other nonsynchronous resources where an additional study process beyond the traditional short circuit ratio calculation is recommended. Study Process Part 1 would serve as a valuable screening tool to identify system areas that would be prone to detrimental inverter based control interactions to the Planning Coordinators. The Planning Coordinators can then utilize Study Process Part 2 to conduct a more detailed analysis of control interactions and develop remedial actions to prevent them.

Observations

Industry studies, most notably in the ERCOT area, have used the study processes documented below. Study Process One has been shown to provide valuable insights into the reactive strength of sub-areas within the network. Study Process Two has then provided additional detail on potential control system interactions that must be addressed in the planning time frame.

Recommendations

- The ERSTF recommends that Planning Coordinators continue to perform traditional short circuit evaluations of their systems per the TPL standard to calculate short circuit ratios and identify weak areas that may require additional traditional voltage and reactive analysis to address potential risks to low-voltage events like FIDVR and voltage instability.
- The ERSTF further recommends that Planning Coordinators employ the suggested additional study processes (Study Process 1 and 2) for areas that either already have or may have significant additions of inverter-based resources or other nonsynchronous resources. The results of this analysis will provide the Planning Coordinators with the necessary information to determine the appropriate reactive support needed and to determine where additional control interaction modifications may be required.
- The Planning Coordinators should strongly consider making the results of these types of studies available to the industry at large as part of an ongoing effort to promote lessons learned for this dynamic and rapidly evolving industry issue.
- The ERSTF proposes that Study Process 1 and 2 be used as an Industry Practice.

Study Process – Part 1

Step 1 – Planners should develop a case that represents anticipated system conditions, including synchronous and nonsynchronous generation commitment at stressed system conditions.

Step 2 – Planners should identify logical voltage/reactive sub-areas within their systems. In general these sub-areas should be based on practical planning and operations experience, and they should typically consider variables such as:

- reactive performance within the footprint,
- real power import, export, and flow-through characteristics,
- transmission topology and typical constraints (e.g., surge impedance loading),
- charging from cables or long overhead lines,
- types of resources (i.e., synchronous and/or nonsynchronous/inverter based),
- existing reactive resources (shunt capacitors/inductors, SVCs, STATCOMs, DVARS, generators, HVDC terminals, series compensation, etc.), and
- real and reactive load distribution.

Step 3 – Planners should then calculate the short circuit ratio for the transmission buses above 100 kV in the sub-areas identified in Step 2 using the following approach. This is a representative indicator of system strength and should be tracked and trended over time.

$$\frac{Lowest\ Short\ Circuit\ Capacity\ in\ a\ sub-area_{\ (MVA)}}{Total\ Nonsynchronous\ Generation\ Capacity\ in\ a\ sub-area_{\ (MW)}}$$

Step 4 – When the short circuit ratio for a sub-area has fallen below 3, system strength is generally considered to be low. This is an indication of potential reliability concerns that may require further investigation, including the control system stability associated with the addition of nonsynchronous or inverter-based resources. An additional assessment of short circuit current and short circuit ratio should be done for weak sub-areas as described in Study Process – Part 2.

Study Process – Part 2

As an additional Industry Practice, further detailed studies are warranted for sub-areas where the short circuit ratio is low and nonsynchronous/inverter-based resources are planned. The planners should calculate the system strength for the identified sub-areas using one of the following approaches:

a. GE's composite short circuit ratio, or
b. ERCOT's weighted short circuit ratio

Planners should also consider using these methods for sub-areas that have traditionally had a high index but are expected to see an increase of nonsynchronous/inverter-based resources.

The study effort to determine relative composite short circuit current and the potential impact on voltage/reactive performance is considered an Industry Practice, and these types of studies should be conducted on a periodic basis or when new nonsynchronous resource additions are planned.

Discussion and Considerations

No industry standard exists for the sub-area short circuit ratio calculation. Further thought and consideration is required to determine the most appropriate short circuit ratio calculation method and the threshold. Actual thresholds should be based on the output of power electronics-based resources instead of capacity.

The increasing penetrations of nonsynchronous resources (including but not limited to wind, solar, and battery storage) could alter system characteristics such as voltage performance and frequency response. These functions have traditionally been provided by synchronous generators, although they can also be provided through fast inverter controls on wind, solar and battery storage plants. However, in situations where the short circuit ratio is low, advanced power electronic devices may not contribute as much as synchronous generators to system strength due to limited short circuit current contribution. A weak grid can also result in potential system stability issues that may cause undesirable oscillation or generation trip during normal or abnormal operations. Therefore, it is important to understand the system strength impact, particularly with changes of generation mix in a region, to ensure that stable operations can be maintained.

From a system assessment perspective, the typical stability analysis using a positive sequence time domain simulation tool focuses on the system response at a frequency less than 10 Hz. The dynamic models applied in such a simulation tool will simplify the high-frequency components, including power electronic controllers, with a fixed time constant or an algebraic equation. Under a weak grid condition, the dynamic stability analysis using the positive sequence simulation tools may not be adequate and the results can be conservatively optimistic. A more detailed analysis may be needed to properly consider all behaviors of the controller under a weak grid condition.

Short circuit ratio is a metric that has traditionally represented the voltage stiffness of a grid. Conventionally, SCR is defined as the ratio of the short circuit capacity, at the bus where the device is located, to the megawatt rating of the device. Based on this definition, SCR is given by:

$$\text{SCR} = \frac{S_{SCMVA}}{P_{RMW}} \qquad (1)$$

where S_{SCMVA} is the short circuit capacity at the bus before the connection of the device and P_{RMW} is the rated megawatt value of the device to be connected.

Equation 1 is the commonly used SCR calculation method when evaluating system strength. The key assumption and limitation of this SCR calculation method is that the studied wind or solar plant does not interact with other such plants in the system. When plants are electrically close to each other, they may interact with each other and oscillate together. In such cases, the SCR calculation using equation 1 can result in an overly optimistic result.

There is currently no industry-standard approach to calculate the proper SCR index for a weak system with high penetration of wind and solar power plants (or other inverter-based resources, such as battery storage). To take into account the effect of interactions between plants and give a better estimate of the system strength, a more appropriate quantity or indicator is needed to assess the potential risk of complex instability. Several approaches, such as GE’s Composite Short Circuit Ratio (CSCR) and ERCOT’S Weighted Short Circuit Ratio (WSCR) method, have been proposed to calculate the SCR for a weak system with high penetration of renewable generation. The CSCR and WSCR methods are described in Appendix E.

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

The low SCR, indicating a weak grid, will serve as a risk indicator to require a more detailed review and modeling for proper reliability assessments. It should be noted that the information obtained in this Industry Practice is to provide an indicator of system strength that will require a more detailed analysis for the identified weak grid condition. It does NOT mean that there is a reliability risk or violation for the identified sub-areas, but instead suggests that additional study and consideration is warranted.

Additional Considerations of the ERSTF

As part of its due diligence, the task force examined the potential impact of Distributed Energy Resources on the BPS. The task force determined DERs should be evaluated to determine any potential impact on the proposed Measures and to identify any necessary follow-up activity that may fall outside the purview of the ERSTF.

Distributed Energy Resources

DERs are becoming a significant element of net load on distribution systems in a few areas of North America. This industry will continue to grow as more announcements are made for future development. From the Bulk Electric System (BES) perspective, distribution load is the combination of connected load and DER generation with the additional influence of DER resources, such as distributed storage, demand-side management, and microgrids, which can both increase and decrease the perceived load at the level of the BES. Although DERs are not explicitly modeled at the BES level today, they will increasingly affect the net distribution load that is observed at the BES level. Taken together, the BES, small resources below the minimum size of BES generator definitions, and net distribution load make up the BPS.

Reliable operation and planning of the BPS requires accurate modeling, forecasting, and measurement of resources, loads, and system topology. The capability of DERs to interact seamlessly with the BPS, such as for frequency and voltage ride-through requirements, is not well coordinated with NERC reliability standards. This lack of coordination can lead to events where the connection and/or disconnection of VERs may abruptly change the net distribution load during frequency excursions or voltage deviations. This may further exacerbate a disturbance on the BPS, while more useful responses from DERs could support the BPS and contribute to reliability and system recovery during disturbances.

A thorough consideration of the reliability coordination and contributions from DERs was beyond the scope of the ERSTF, but the task force considers such activities to be increasingly important and makes the following general recommendations:

- To minimize the possibility of unintended DER impacts on the BPS, DER frequency and voltage ride-through requirements should be considered with regard to NERC Reliability Standards. IEEE Standard P1547, a DER interconnection standard, is currently being revised by the IEEE Standards Association in project IEEE P1547. Efforts to further coordinate IEEE P1547 with NERC Reliability Standard PRC-024-2 (Generator Frequency and Voltage Protective Relay Settings) and other relevant standards should continue with the objective that DERs meet or exceed reliability similar to BES resources to address any unintended consequences that could occur during operation of the BPS. Participation by Transmission Operations and Planning subject matter experts in the IEEE P1547 drafting effort is strongly recommended to provide a BPS perspective to inform the IEEE P1547 drafting team efforts.
- In several regions, DERs are poised to reach levels that will have significant influence on BPS operations either on an individual or aggregated basis. This provides both opportunities and challenges that need to be represented in models, planning activities, and operating practices. Pursuant with NERC's Reliability Assessment obligations, the ERSTF recommends that NERC establish a working group to further examine the ability to forecast, visibility, control, and participation of DERs as an active part of the BPS. With prudent planning, operating, and engineering practices, and policy that is oriented to support reliability, DERs should be able to be reliably integrated into BPS operation.

Summary and Conclusions

The North American BPS is undergoing a significant change in the mix of generation resources. Various factors are leading to a future mix that uses less coal, more natural gas, more wind and solar, and more forms of distributed generation and demand response. NERC created the Essential Reliability Services Task Force in 2014 to consider these changes and identify measures to assess reliable operation of the BPS.

The task force found that the most important essential reliability services largely encompass managing frequency, net demand ramping, voltage performance, and dispatchability. This report describes a set of Measures and Industry Practices in precise detail; this section provides a high-level review of the key findings.

The task force looked closely at the North American BPS, especially those areas that are experiencing the greatest level of change in types of resources used to serve load. While the behaviors of conventional generators are well documented, the task force also reviewed the capabilities of newer technology such as wind, solar, battery storage, and other types of generators. Based on this analysis, a number of Measures and Industry Practices were then identified, with the recommendation that Measures should be tracked and Industry Practices should be used by the appropriate entities as the generation mix changes over the coming years. The Measures and Industry Practices are designed to assist the impacted entity in handling real-time operational concerns as well as comprehensive planning for future resource changes.

Frequency – Many of the Measures relate to restoring frequency after an event such as the sudden loss of a major resource. The frequency within an interconnection will immediately fall upon such an event, requiring a very fast response from some resources to slow the rate of fall, a fast increase in power output (or decrease in power consumption) to stop the fall and stabilize the frequency, then a more prolonged contribution of additional power (or reduced load) to compensate for the lost units and bring system frequency back to the normal level. The task force recommends Measures to track the minimum frequency of a system and frequency response following the observed contingency events, track and project the levels of conventional synchronous inertia for each balancing area and the interconnection as a whole, and track and project the initial frequency deviation in the first half-second following the largest contingency event for each interconnection.

Ramping – Ramping is related to frequency, but more in an “operations as usual” sense rather than after an event. Changes in the level of nondispatchable resources, system constraints, load behaviors, and the generation mix can impact the ramp rates needed to keep the system in balance. The task force recommends a Measure to track and project the maximum one-hour and three-hour ramps for balancing areas that may experience such concerns.

Voltage – Voltage must be controlled to protect the system and move power where it is needed. This tends to be more local in nature, such as at individual transmission substations, in sub-areas of lower-voltage transmission nodes and the distribution system. Ensuring sufficient voltage control and “stiffness” of the system is important both for normal operations and for events impacting normal operations (i.e., disturbances). The task force recommends Measures to track and project the static and dynamic reactive power reserve capabilities to regulate voltage at various points in the system. Industry Practices are also recommended to monitor events related to voltage performance, periodically review the short circuit current at each transmission bus in the network, and do further analysis of short circuit ratios when penetration of nonsynchronous generation (wind, solar, batteries, etc.) is high or anticipated to increase.

The detailed Measure recommendations are summarized as follows:

- Frequency Support Recommendations
  - Calculate the instance of minimal synchronous inertial response (SIR) that occurred in the recent historical study year and its projected value for the next three years (Measure 1 for interconnection and Measure 3 for BAs).
  - At minimum SIR conditions for each of the historical and future years above, determine the frequency deviation that would result within the first 0.5 seconds following the largest contingency of the interconnection (Measure 2 for interconnection).
  - Each interconnection should measure the minimum frequency point (the Nadir) and all aspects of frequency response following observed contingency events (Measure 4).
  - A measure related to situational awareness modeling of available inertia for near-real-time applications when operating the grid was considered. This was identified as an Industry Practice but not recommended as a measure.
- Net Demand Ramping Variability Recommendations
  - Each BA should calculate the historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net demand ramps (actual load less production from VERs) using one-minute data (Measure 6). Although changes in ramping needs may not indicate a concern, the historical and projected ramp values by BA should be reviewed at both the BA and NERC level to allow for early identification of potential areas for further analysis.
- Voltage Support Recommendations
  - Measures of reactive capability should be calculated and tracked by the appropriate registered entity, including both static and dynamic reserve capability per total megawatt load at peak, shoulder, and light load levels; and load power factor for distribution at the low side of transmission buses at peak, shoulder, and light load levels (Measure 7).
  - The ERSTF considered, but does not recommend, potential measures of voltage performance for tracking voltage exceedances during real-time operations and monitoring buses with low short circuit strength or susceptibility to fault-induced delayed voltage recovery (FIDVR) conditions (Measure 8).
  - The ERSTF discussed a potential measure for reviewing system events that suggest stressed reactive capability or degraded voltage profiles to compare planned performance with real-time operations and evaluate voltage performance. This was identified as an Industry Practice but not recommended as a Measure.
  - The appropriate registered entity should measure system strength based on calculating short circuit ratios for sub-areas in the system. This was identified as an Industry Practice but not recommended as a Measure.

The ERSTF has made an initial effort to encourage industry to think more carefully about what system behavior exists today, how this behavior may change in the future, what characteristics will be needed from resources in the future, and how to make the transition in a reliable way. New resources may have different operating characteristics but can be reliably integrated with proper planning, design, and coordination. Maintaining reliability is embodied in the predictability, controllability and responsiveness of the resource mix. At a higher level, this suggests several general recommendations:

1. Recommend that all new resources have the capability to support voltage and frequency. Automatic voltage regulators and governors have been standard on conventional generators for decades and

comparable capabilities are currently available for new VERs and other resources. Ensuring that these capabilities are present in the future resource mix is prudent and necessary.

2. Recommend the monitoring of the Measures and investigation of trends. The Measures are intended to highlight aspects that could suggest future reliability concerns if not addressed with suitable planning and engineering practices.
3. Recommend planning and operating entities to use the Industry Practices. While the results of Industry Practices will be system-specific and difficult to quantify or compare between different regions, they will help ensure that emerging concerns are addressed with suitable planning and engineering practices.
4. While beyond the formal scope of the ERSTF, the task force recognizes that Distributed Energy Resources (DERs) will increasingly affect the net distribution load that is observed by the BPS. The ERSTF recommends coordination of NERC Reliability Standards with DER equipment standards such as IEEE 1547.
5. Recommend open sharing of experiences and lessons learned. Provided that we act prudently, the reliability of the system can be maintained or improved as the resource mix evolves.

Federal, state, and local jurisdictional policy decisions can have a direct influence on changes in the resource mix and thus can also affect the reliability of the BPS. As the resource mix continues to change, it is necessary for policy makers to recognize the need for essential reliability services in the current and future mix of resources. Analyses of this transformation must be done to allow for effective planning and provide system operators the flexibility to modify real-time operations for reliability of the electric grid. The NERC ERSTF recommendations will assist in informing policy makers of the implications of the changing resource mix and will strengthen the ability of the electric power industry to manage the evolution of the system in a reliable manner.

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

Appendix A – Frequency Support

Inertial Response

Rotating turbine generators and motors that are synchronously interconnected to the system store kinetic energy during contingency events that is released to the system, also called inertial response. Inertial response provides an important contribution in the initial moments following a generation or load trip event: determining the rate of change of frequency. In response to a sudden loss of generation, kinetic energy will automatically be extracted from the rotating synchronized machines on the interconnection, causing them to slow down and causing frequency to decline. The amount of inertia depends on the number and size of generators and motors synchronized to the system, and it determines the rate of frequency decline. Greater inertia reduces the rate of change of frequency, giving more time for primary frequency response to fully deploy and arrest frequency decay above under-frequency load shed set points.

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

Frequency Response (Primary Frequency Control)

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

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

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

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

Synchronized turbine generator automatic control systems (governors) can sense the decline in frequency and control the generator to increase the amount of energy injected into the interconnection. Frequency will continue to decline until the amount of energy is rebalanced[11] through the automatic control actions of primary frequency

[11] Offsets the amount of energy lost and replaces the amount of kinetic energy supplied by inertia.

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

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

The Purpose of this procedure is to:

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

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

1.1 Data requirements (from BAs in an interconnection)

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

1.2 Additional data requirements (at interconnection level)

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

1.3 Calculation procedure

1. Calculate H_i*MVA_i for each generator *i*.

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

$$KE(t) = \mathrm{sum}(H_i*MVA_i) \quad (1)$$

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

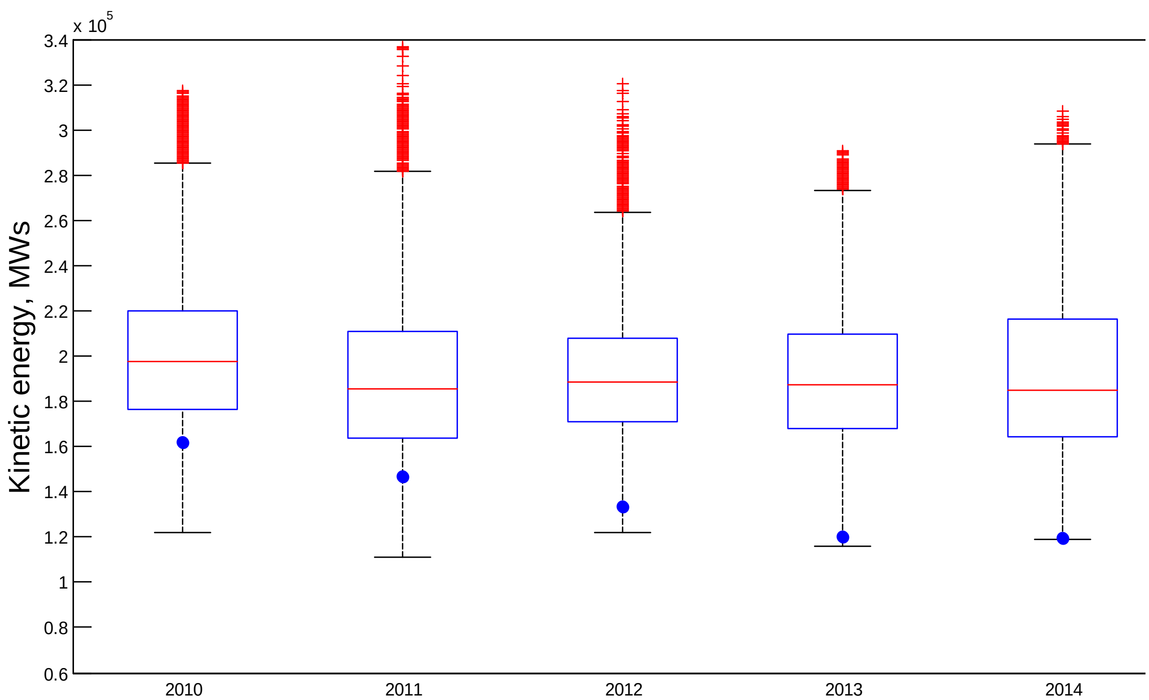


Figure A.1: Boxplot of historic kinetic energy or synchronous inertia (2010–2014)

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

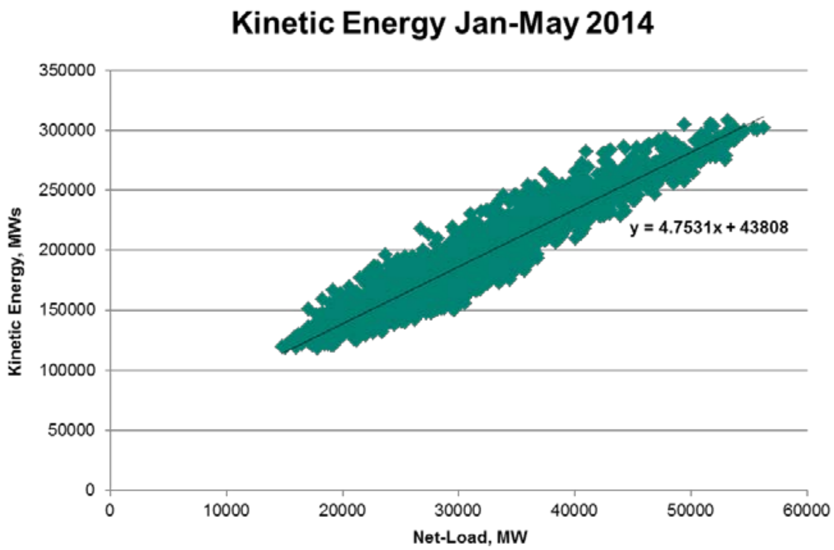


Figure A.2: Hourly system inertia Jan–May 2014 vs corresponding system hourly net demand for ERCOT system with linear trend line

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

1. For each historic year and at minimum kinetic energy conditions KE_{min}, calculate RoCoF over the first 0.5-second window after the largest contingency ΔP_{MW} (as defined by the RCC in BAL-003-1 (e.g., RCC for ERCOT is 2750 MW)).
   Rate of change of frequency over the first 0.5-second window after the contingency is calculated as:
   a. For systems where load damping constant D is not available:

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

   Note: Here with load damping constant D assumed to be 0, RoCoF is independent of a time window (for the first few seconds before governor response becomes effective). KE_{RCC} is kinetic energy of the largest contingency, i.e. $H*MVA$ of the largest unit(s) as defined by RCC in BAL-003-1.

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

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

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

   Corresponding RoCoF is calculated as

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

2. Calculate corresponding system frequency as:

$$f_{0.5} = f_o - 0.5 * \text{RoCoF} \qquad [\text{Hz}] \tag{5}$$

f_o is predisturbance frequency, assumed to be 60 Hz.

Example:

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

Calculation procedure

1. Convert Load damping into percent load change per 1 percent frequency change
   1 Hz=1/60=1.67 percent of 60 Hz
   D=2.44/1.67=1.46 pecent per 1 percent frequency change
2. $\Delta f_{0.5} = \frac{\Delta P_{MW}}{D \cdot P_{load}} \cdot \left(1 - e^{\frac{0.5 \cdot D \cdot P_{load}}{2 \cdot KE(t)}}\right) \cdot 60 = \frac{2750}{1.46 \cdot 24744.66} \cdot \left(1 - e^{\frac{0.5 \cdot 1.46 \cdot 24744.66}{2 \cdot 147081}}\right) \cdot 60 = 0.272$ [Hz]
3. *RoCoF*=0.272/0.5=0.544 Hz/s
4. $f_{0.5}=f_o-0.5*RoCoF$=60-0.5*0.544=59.728 Hz

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

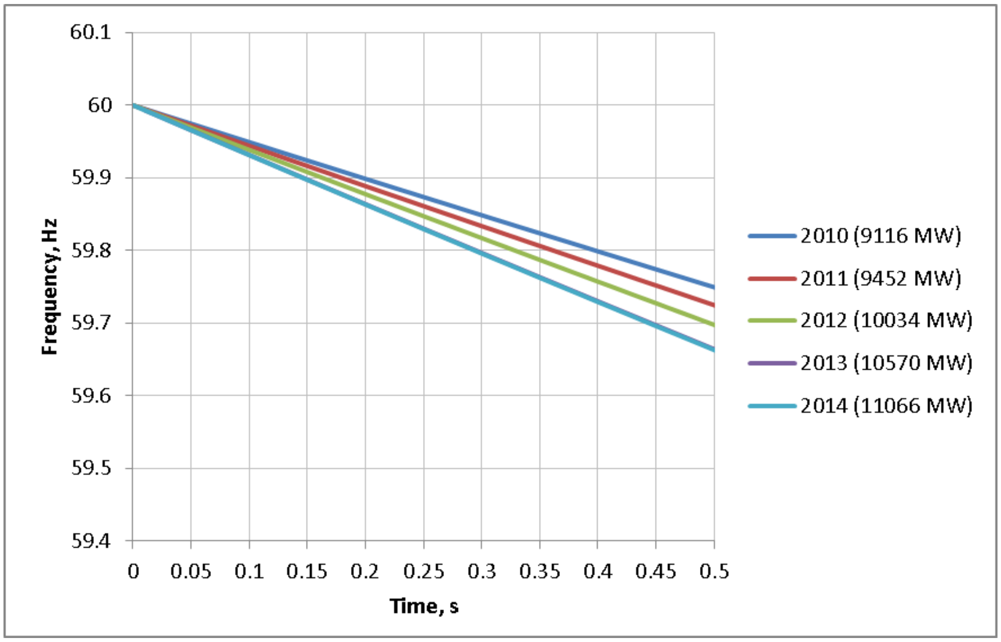


Figure A.3: Calculated system frequency after 2750 MW generation trip, during nonsynchronous generation penetration peak in ERCOT for years 2010–2014

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

3. Analyze hours of highest instantaneous nonsynchronous generation penetration in a number of historic years to calculate future projections.

3.1 Additional data requirements (from BAs in an interconnection)

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

3.2 Calculation procedure

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

Example:

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

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

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

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

Example:

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

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

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

4 Projecting kinetic energy and RoCoF at renewable penetration peak hour for a future year Additional data requirements (for BAs in an interconnection)

- Expected installed nonsynchronous generation-by-generation technology in a future year based on generation interconnection agreements (GIAs), financial commitments (FCs), and other criteria, e.g., $P_{installed\_wind\_future}$

4.2 Calculation procedure

1. Project system load $P_{load,\ future}$ during nonsynchronous generation penetration peak based on the analysis and findings from Section 1, step 4.

> **Example:**
>
> For the ERCOT system, it was found that during nonsynchronous generation penetration peak hours for years 2011–2014, system load was nearly the same. Therefore, average system load from years 2010–2014, nonsynchronous generation penetration peak hours, was assumed even for projected nonsynchronous generation peak hours ($P_{load,\ future}$ = 24,700 MW) in future years 2015–2017.

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

   Total nonsynchronous generation during projected nonsynchronous generation penetration peak in a future year is then $P_{NSG\_future} = P_{wind\_future}(t_{max}) + P_{PV\_future}(t_{max})$.

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

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

3. Calculate projected net demand, $P_{NL,future} = P_{load,future} - P_{NSG,future}$

4. Calculate projected system kinetic energy during nonsynchronous generation penetration peak based on the trend line obtained in Section 1.3 step 8 (e.g., linear trend line $KE = a \cdot P_{NL}+b$), at $P_{NL}= P_{NL,future)}$.
5. Plot projected kinetic energy on the same figure as boxplots (Figure A.1) to obtain the figure below (which is identical to Figure 1).

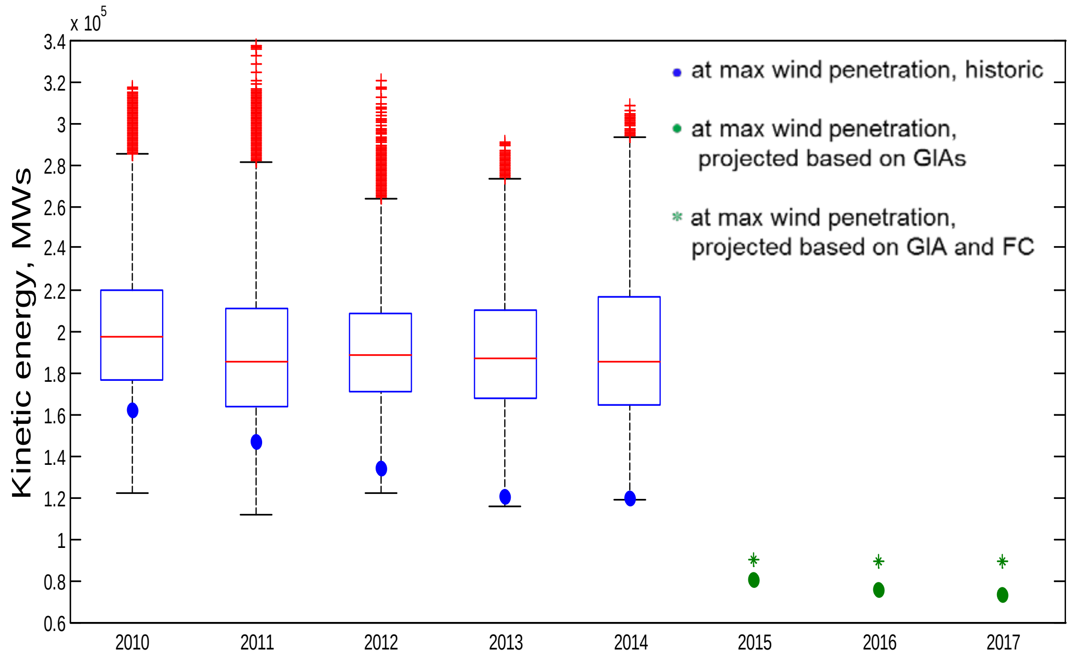


Figure A.4: ERCOT historic kinetic energy boxplots (2010–2017)

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

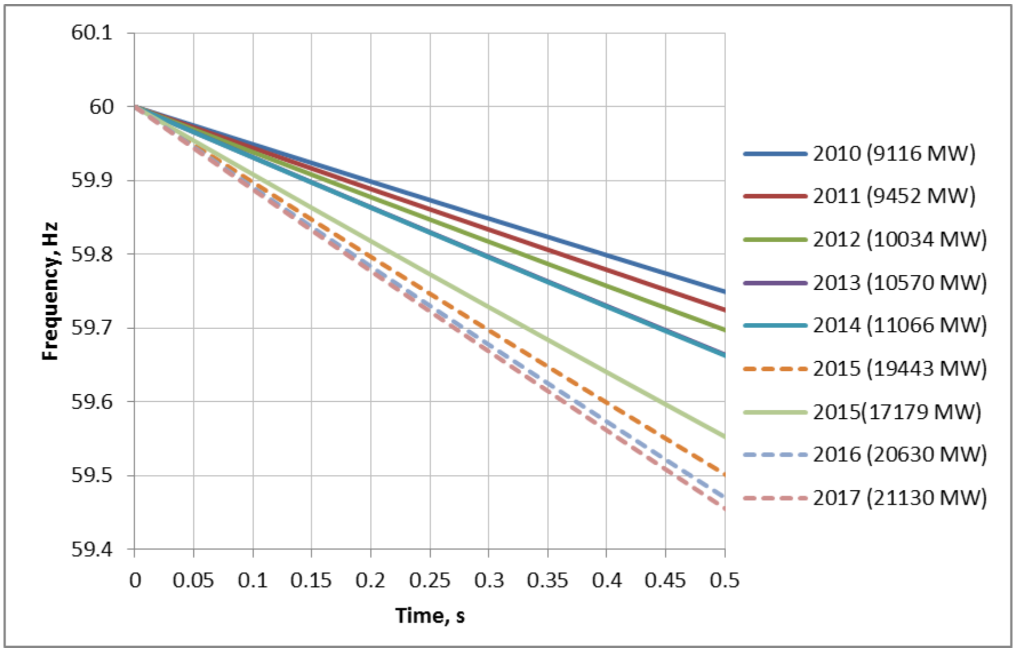


Figure A.5: Calculated system frequency after 2750 MW generation trip (2010–2017)

Results of Analysis

Measure 1: Synchronous Inertial Response at an Interconnection Level

WECC

There is currently not a practical way to find out the minimum inertia hour or the minimum generator capacity hour. Peak Reliability[12] can currently find the hour with minimum generation/load. Peak Reliability determined the minimum generation hour and provided a Westwide System Model (WSM) state estimator case for that time. To determine system-synchronous inertia during the minimum load hour, the WSM generators must be mapped to planning base-case generators. The generator plants (such as wind farms) are not all modeled in the same aggregations, compounding the difficulty of matching them up. As of January 2, 2015, 2913 out of the 3426 generators represented in the current WSM model were mapped to a recent planning base case (see Table A.1). There were still 513 unmapped WSM units represented as generators. The inertia constant and MVA base for the unmapped generators are unknown.

Table A.1: Number of Unmapped Units between WSM and WECC Planning Cases

Cases	WSM Case Units	Unmapped WSM Case Units
Jan 2, 2015	3,426	513
Nov 2, 2014	3,416	526
April 1, 2013	3,164	836

[12] Peak Reliability's two Reliability Coordination (RC) Offices provide situational awareness and real-time monitoring of the Reliability Coordinator Area within the Western Interconnection. Peak Reliability's RC Area includes all or parts of 14 western states, British Columbia, and the northern portion of Baja California, Mexico. Peak Registered Functions: Peak is listed on the NERC Compliance Registry to perform the RC and Interchange Authority (IA) functions as statutory activities.

It is impractical to compare on-line inertia going back in time, because the correspondence between units in the two models is improving with time, so the basis changes for older cases as fewer units were mapped going further back in time. The conclusion is that it will not be practical to try to trend inertia for the Western Interconnection on an ad-hoc basis. Trending will require significant initial effort to assign inertia to each generator unit in the WSM and that would have to be part of the data stored for each unit and maintained with the WSM.

Even though it was not practical to calculate system inertia for historic years 2011–2013 for WECC, Table A.2 shows how installed wind and solar generation capacity was increasing over these years. It also shows historic information for minimum load hours in each year.

Table A.2: Supporting Data for Measure 1 Analysis

	2011	2012	2013	2014
Wind Installed Capacity, P_{wind_inst}	14,046	15,738	18,488	
PV Installed Capacity, P_{PV_inst}				
Supporting Data at Minimum Load Hour				
Date	5/30, 4am	10/14, 4am	4/1, 3am	11/2, 3:48 am
P_{wind}/ P_{load}	4.3%	4.6%	5.6%	
P_{wind}	3,084	3,357	4,161	
P_{load}, MW	70,925	72,898	74,097	
P_{wind}/P_{wind_inst}	22.0%	21.3%	22.5%	

Table A.3: SIR for Different WSM Cases in 2014 and WECC Planning Cases for 2015

Date WSM Cases	System MVA	SIR, MW	Average H	Comment
1-Jul-14	216,536	821,212	3.79	WECC Peak
2-Nov-14	162,444	593,100	3.65	WECC Minimum
Early Nov, 2014	185,777	681,534	3.67	
19-Nov-14	196,883	731,101	3.71	
2015 HS4A1	253,596	932,130	3.68	2015 Heavy Summer
2015 HWA1	228,247	851,119	3.73	2015 Heavy Winter

Measure 2: Initial Frequency Deviation Following Largest Contingency

ERCOT

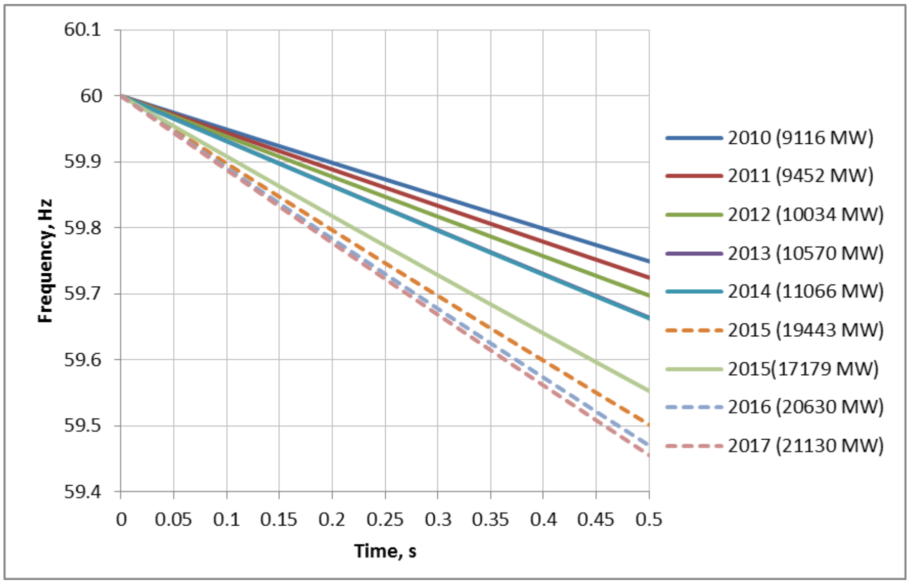


Figure A.6: Calculated system frequency after 2750 MW generation trip (two South Texas Project nuclear units) during nonsynchronous generation penetration peak in ERCOT for years 2010–2014.

Table A.4: Supporting Data for Measure 2 Analysis

	2010	2011	2012	2013	2014	2015 (w. FC)	2015	2016	2017
Installed Capacity (P_{wind_inst}), MW	9,116	9,452	10,034	10,570	11,066	17,179	19,443	20,630	21,130
Installed PV Capacity (P_{solar_inst}), MW	15	42	82	121	159	189	189	394	394
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{wind}/P_{load} ratio									
P_{wind}/P_{load}	25.5%	27.4%	29.8%	35.8%	39.4%	61%	69%	73.2%	75%
P_{wind}, MW	6,483	6,772	7,247	8,773	9,699	15,057	17,041	18,082	18,520
P_{wind}/P_{wind_inst}	71%	72%	72%	83%	88%	88%	88%	88%	88%
Net Demand, (P_{load}-P_{wind}), MW	18,944	17,973	17,082	15,716	14,918	9,643	7,659	6,618	6,180
Inertia, MWs	161,741	147,081	133,675	120,030	119,604	89,469	80,020	75,066	72,979
Estimated RoCoF after loss of 2x1375 MW, Hz/s	0.501	0.551	0.605	0.672	0.674	0.89	0.996	1.059	1.088

For 2015 the projections are done in two ways: for planned projects with signed interconnection agreements, and for planned projects with both signed interconnection agreements and financial commitments.

WECC

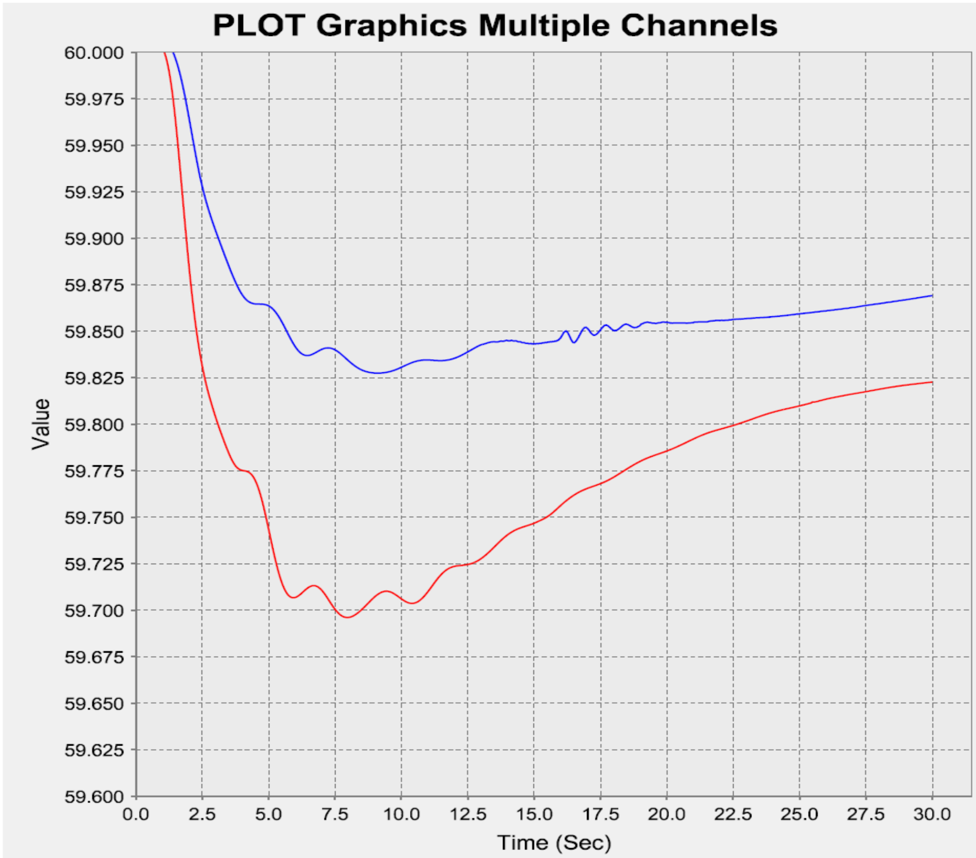


Figure A.7: Simulated WECC system frequency following 2750 MW generation trip

Figure A.7 shows frequency traces from the simulated loss of two Palo Verde units (Resource Contingency Criteria for WECC) for WECC 2014 peak (blue) on July 1, 2014, and the WECC 2014 low load (red) on November 2, 2014 cases. It is interesting to note the large difference the load level makes on the frequency nadir for the two cases.

Eastern Interconnection

The Eastern Interconnection at present has a relatively low penetration of inverter-based resources, so system inertia and frequency response continues to be dominated by load level and the accompanying unit commitment. On August 4, 2007, a major event occurred that included the loss of approximately 4,500 MW of generation. That event was the basis for the EI FRO *NERC Frequency Response Initiative Report*. Events of that size result in frequency excursions on the order of 0.1 to 0.2 Hz. The event in Figure 4 occurred at near-peak-load conditions. Unlike the other interconnections, the EI exhibits a substantially different response characteristic (occasionally referred to as the "lazy L") without a clear nadir and with degrading frequency over the period during which frequency response is calculated according to BAL-003-1. Thus, today in the east, the system inertia is relatively unimportant compared to the primary response of generation. And the overall interconnection frequency response is dominated by automatic load control (governor withdrawal) on the relatively few generators in the EI that have governors enabled for under-frequency response.

At light load, with fewer generators committed, the character of the EI frequency response is similar, but the amplitude of the frequency excursion tends to be worse. For comparison, a simulation of an event similar to that of Figure 3 is included in Figure A.9, but for low load conditions.[13]

Tracking of the status and capability of governors in the EI, including understanding (and modeling) of automatic load control, is critical to understanding frequency response.

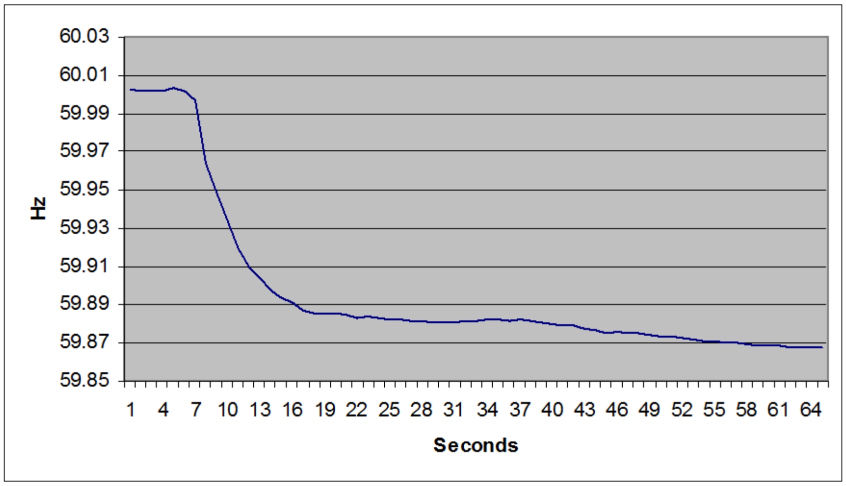


Figure A.8: 4500 MW EI event of August 4, 2007

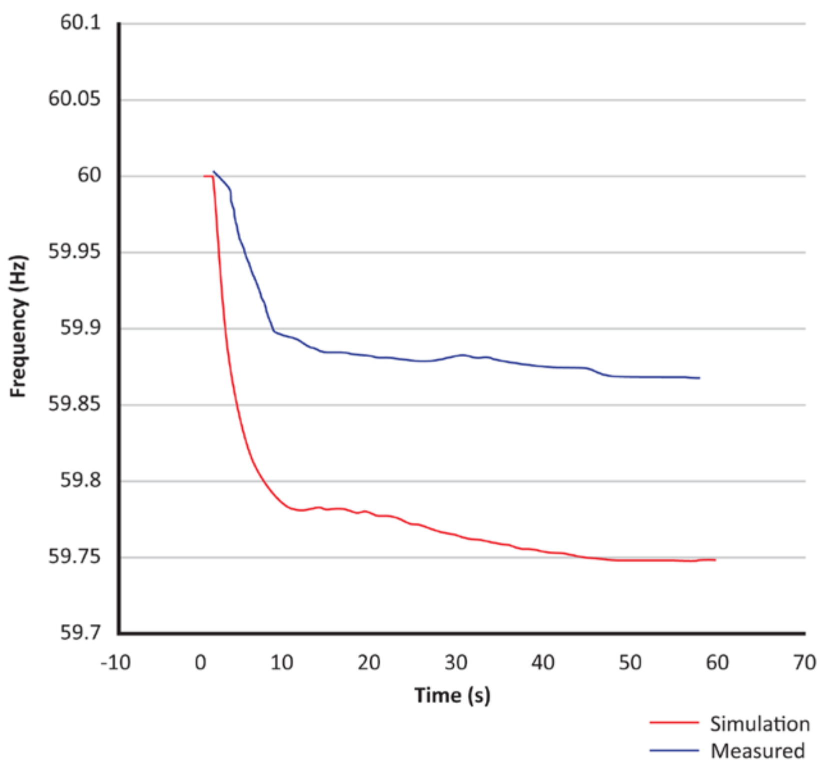


Figure A.9: Measured Event near Peak Load and Simulated Event near Minimum Load

[13] GE Energy (2013). Eastern Frequency Response Study. NREL/SR-5500-58077. Golden, CO: National Renewable Energy Laboratory. May 2013

Measure 3: Synchronous Inertial Response at a BA Level

ERCOT

Figure A.10 shows boxplots for Measure 3[14] (i.e., hourly synchronous inertia (kinetic energy) in MW) for 2010–2014. The blue dots on each boxplot correspond to the nonsynchronous (i.e., wind) generation peak. In the ERCOT system, nonsynchronous generation peaks are encountered predominantly in spring or fall during the early night hours (2–3:00 a.m.). During these hours, wind resources account for over 70 percent of total generation output on the system, displacing more expensive synchronous generation. Note that during times of low load and high wind output, ERCOT is normally exporting power over HVDC ties. Therefore, there is no additional nonsynchronous contribution over the HVDC ties during these periods.

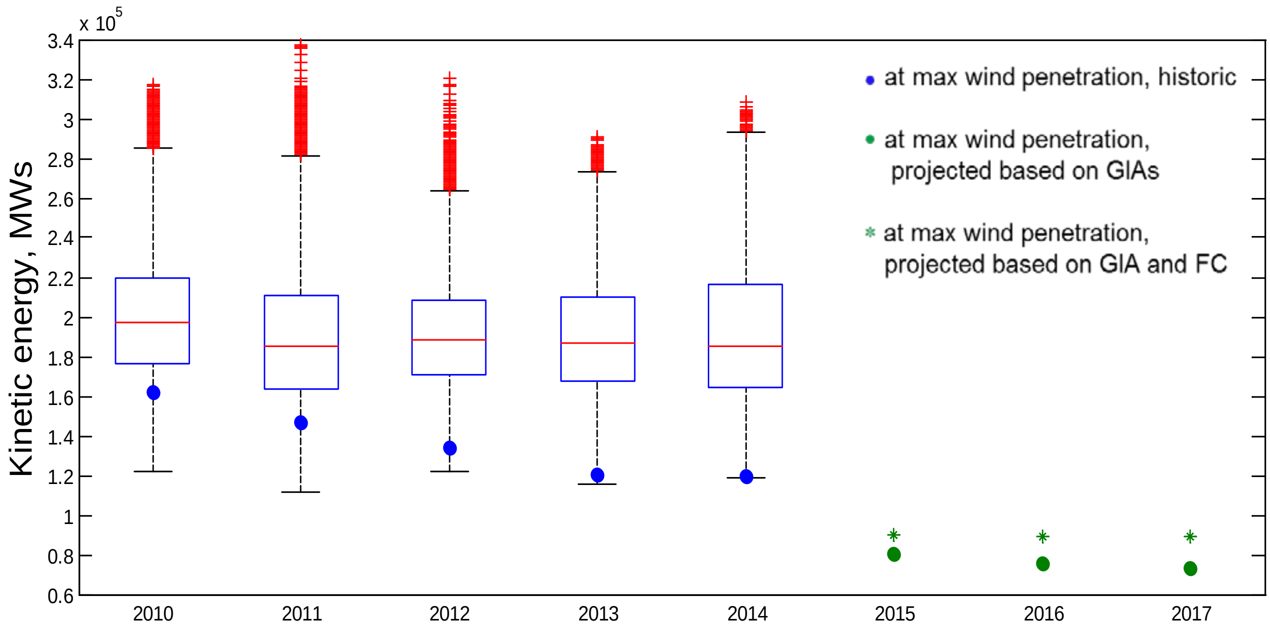


Figure A.10: Measure 1 and Measure 3 for ERCOT historic SIR boxplots and future projections of SIR at peak nonsynchronous generation penetration hour

With installed wind generation capacity increasing from 9 GW in 2010 to 11 GW in 2014, the hour of peak nonsynchronous penetration is also the lowest synchronous inertia hour in the year.

Kinetic energy during the projected peak penetration of wind generation for years 2015–2017 is based on the expected installed capacity of the projects with GIAs and on expected installed capacity of the projects with FCs and GIA. At the end of 2013, many wind generation projects started construction in order to be able to receive the Production Tax Credit. These projects are currently in different stages of construction with expected completion dates between 2015 and 2017.

[14] Note ERCOT is single interconnection and BA, therefore Measure 3 and Measure 1 for ERCOT are the same.

Table A.5: Supporting Data for Measures 1 and 3 Analysis								
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Installed Wind Capacity (P_{wind_inst}), MW	9,116	9,452	10,034	10,570	11,066	19,443	20,630	21,130
Installed PV Capacity (P_{solar_inst}), MW	15	42	82	121	159	189	394	394
Supporting Data at max wind penetration hour; i.e., an hour with maximum P_{wind}/P_{load} ratio								
P_{wind}/P_{load}	25.5%	27.4%	29.8%	35.8%	39.4%	69%	73.2%	75%
P_{wind}, MW	6,483	6,772	7,247	8,773	9,699	17,041	18,082	18,520
P_{wind}/P_{wind_inst}	71%	72%	72%	83%	88%	88%	88%	88%
P_{load}, MW	25,427	24,745	24,328	24,488	24,617	24,700	24,700	24,700

Synchronous Inertial Response (SIR) distribution in years 2010–2014 is largely unchanged; however, beginning in 2013 and 2014, the hour of maximum wind penetration and minimum inertia coincide. This is due to higher levels of installed wind generation and high wind power production during low load hours at night in spring months.

ERCOT found Measure 3 very informative. ERCOT is a single interconnection and relies only on local resources for frequency support. ERCOT has also put in place a real-time synchronous inertia calculator. It is not currently used in the control room, but is used for off-line analysis and future trending.

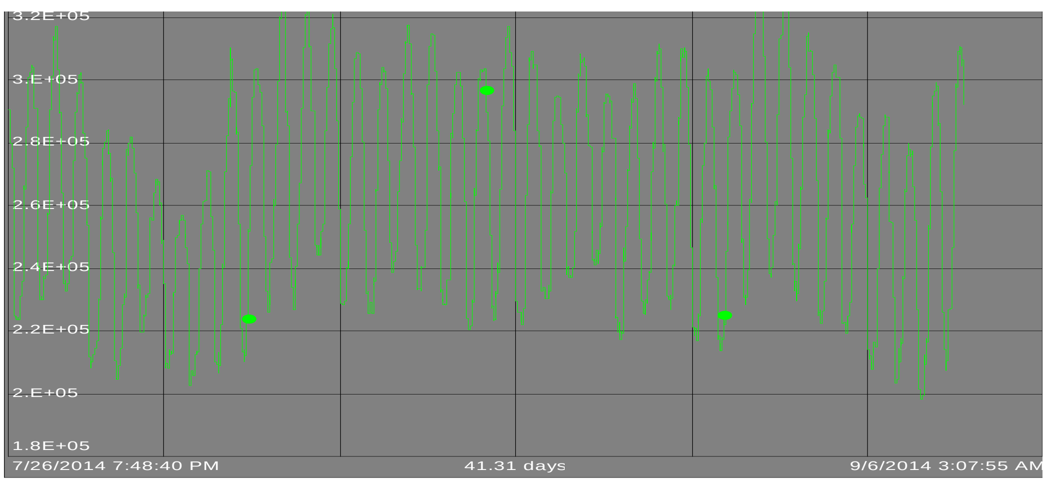


Figure A.11: Snapshot from the real-time SIR calculator in ERCOT

ISO New England

In ISO NE, since a comprehensive data set for an entire year was not readily available, engineering judgment was used to select hours in the year with representative system inertia values. During low inertia hours, ISO NE is importing power over HVDC ties (about 8–9 percent of load at the time). HVDC imports and coincidental wind power production result in up to 4 percent nonsynchronous penetration in historic years 2011–2014.

Future projections are made from the average historical trend due to a full year's data not being available to produce boxplots and find true minimum inertia hours. In future years, installed wind generation capacity in ISO NE is expected to increase from 607 MW to 3043 MW, while HVDC tie capacity remains the same. This leads to projected nonsynchronous penetration of 22 percent of load by 2015 and decline in synchronous inertia.

ISO NE found Measure 3 of value for their system and will continue system inertia tracking since it also aligns with their PFR tracking initiative.

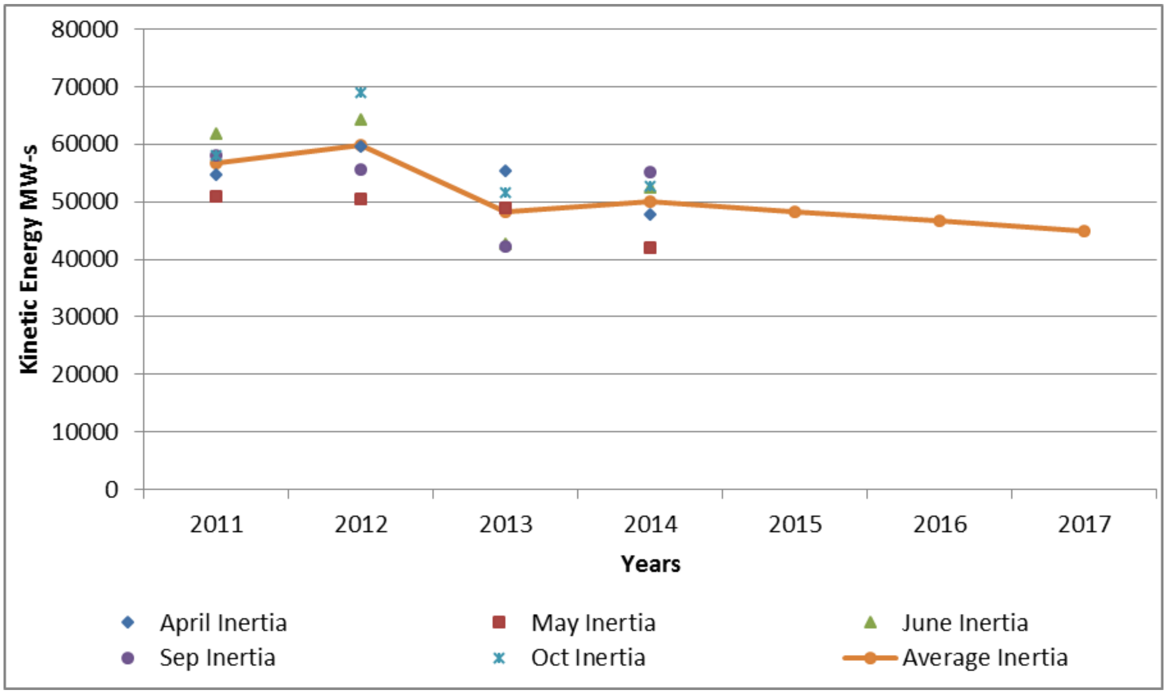


Figure A.12: Measure 3 for ISO NE. Historic SIR based on typical snapshots. Future projections of SIR are based on average SIR conditions in 2014.

Table A.6: Supporting Data Measure 3 Analysis

	2011	2012	2013	2014	2015	2016	2017
Installed HVDC Capacity (P_{HVDC_inst}), MW	2,548	2,548	2,548	2,548	2,548	2,548	2,548
Installed Wind Capacity (P_{wind_inst}), MW	274	345	607	607	991	2,661	3,043
Total Nonsynch Capacity, MW	2,822	2,893	3,155	3,155	3,539	5,209	5,591
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{NSG}/P_{load} ratio							
P_{HVDC}, MW - at min inertia	758	738	801	857	857	857	857
P_{HVDC}/P_{HVDC_inst}	30%	29%	31%	34%	34%	34%	34%
P_{wind}, MW - at min inertia	122	90	112	24	257	963	1,219
P_{wind}/P_{wind_inst}	45%	26%	18%	4%	26%	36%	40%
P_{NSG}/P_{load}	10%	10%	10%	10%	12%	20%	23%
P_{load}, MW - at min inertia	9,033	8,654	9,471	9,210	9,210	9,210	9,210

IESO

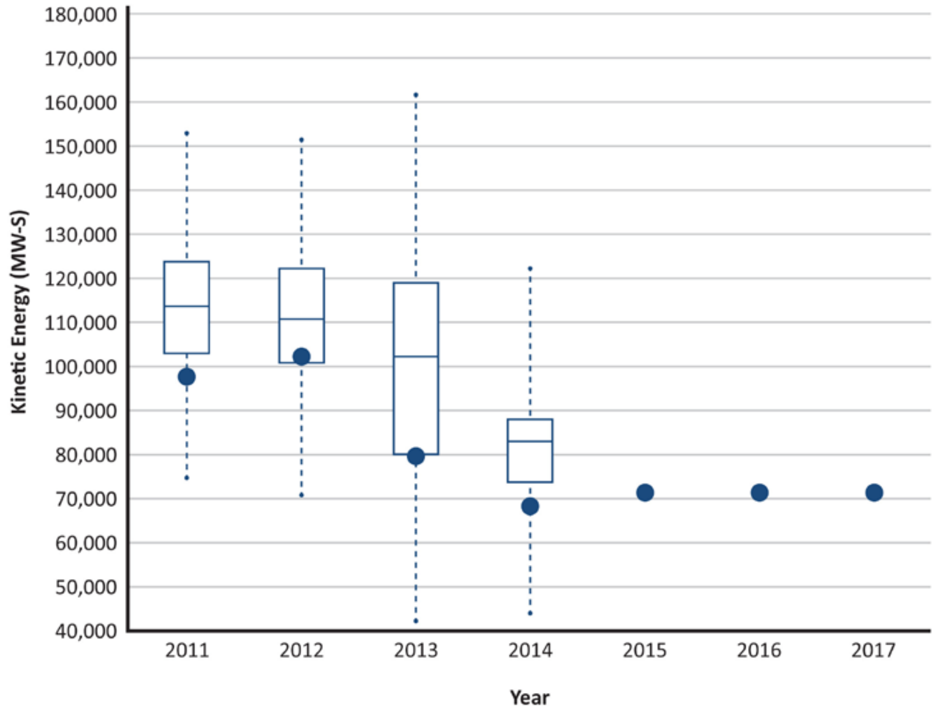


Figure A.13: Measure 3 for IESO. Historic SIR boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Blue dots correspond to peak nonsynchronous generation penetration hour in each year.

Table A.7: Supporting Data Measure 3 Analysis							
	2011	2012	2013	2014* (Jan - Oct)	2015	2016	2017
Installed Capacity (HVDC line Capability included), MW	2,955	2,955	3,452	4,075	5,607	5,607	5,607
Installed Wind, MW (Maximum during the year)	1,725	1,725	2,222	2,845	4,377	4,377	4,377
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{NSG}/P_{load} ratio							
Max P_{wind}/P_{load}	11.2%	14.3%	14.6%	16.3%	22%	22%	22%
P_{wind} (HVDC included)	1,794	2,560	3,114	2,735	4,055	4,055	4,055
HVDC imports (interpolated flow values includes off-market transactions)	600	969		664	664	664	664
$P_{wind}/P_{install}$	62%	87%	90%	72%	72%	72%	72%
P_{load}, MW	16,084	17,937	21,335	16,822	18,045	18,045	18,045
Minimum Market Demand	12,605	11,974	12,762	12,741			

IESO historical maximum nonsynchronous penetration hours happened in the early morning or afternoon hours in spring and fall (see Table A.8).

Table A.8: Historic Dates and Times for Maximum Nonsynchronous Generation Penetration

Date	Hour Ending	Max NSG penetration
11/25/2011	14	11.2%
03/28/2012	7	14.3%
11/18/2013	18	14.6%
04/10/2014	6	16.3%

MISO

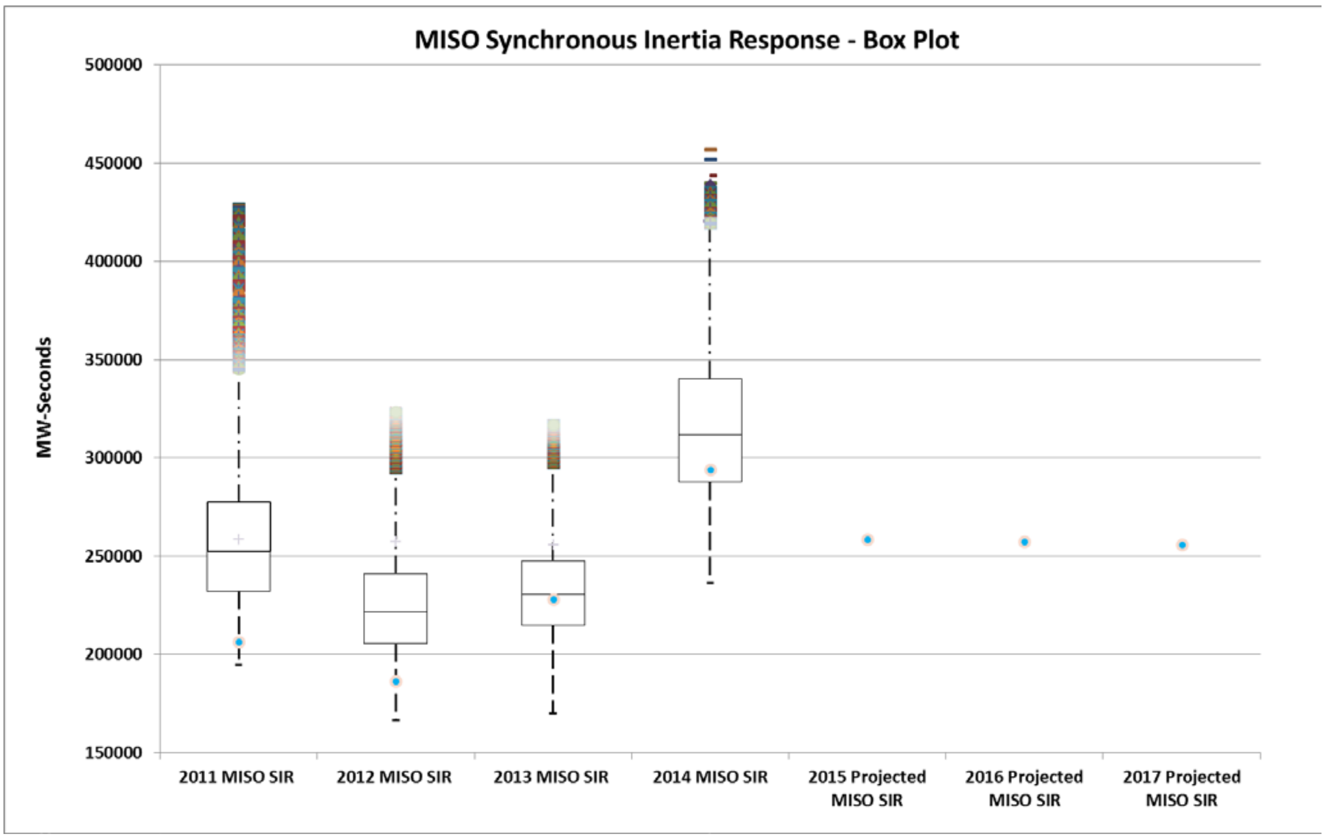


Figure A.14: Measure 3 for MISO. Historic SIR Boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Blue dots correspond to peak nonsynchronous generation penetration hour in each year.

Table A.9: Supporting Data for Measure 3 Analysis							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Installed Wind Capacity (P_{wind_inst}), MW	10,628	12,270	13,035	13,726	15,476	17,001	18,526
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{NSG}/P_{load} ratio							
P_{wind}/P_{load}	16%	25%	21%	16%	18%	20%	21%
P_{wind}, MW	7,665	9,906	9,705	9,653	10,883	11,956	13,028
P_{wind}/P_{wind_inst}	72.12%	80.73%	74.45%	70.32%	70.32%	70.32%	70.32%
P_{load}, MW	49,190	40,191	47,263	59,119	59,711	60,308	60,911

MISO does not have any HVDC ties that cross the BA boundary. Thus, maximum nonsynchronous generation penetration is only driven by wind generation. Over the years, MISO has had some large load changes within the Balancing Authority area during the time frame of this collection, so results and trends do reflect that: First Energy left the MISO BA in June 2011 (less load in the BA, but no change in wind), and the integration of the South Region (added load, no wind) into the MISO BA in December 2013 (including Entergy, Cleco, SMEPA, LAGN). Table A.10 shows minimum and maximum load from 2011 through 2014 for reference.

Table A.10: MISO Minimum and Maximum Load 2011–2014		
	Max MISO Load MW	**Min MISO Load MW**
2011	10,0795	41,118
2012	94,468	39,049
2013	92,034	36,919
2014	111,318	50,824

Future projections are based on a 1 percent load growth factor and projected wind-installed capacity megawatts. Since the MISO system has undergone some changes in 2011 and 2013, the future SIR projections are based on 2014 inertia trends.

MISO found Measure 3 useful for their system and set up a real-time system inertia calculator. Figure A.15 illustrates real-time system inertia along with wind, load, and generation, calculated every 15 minutes since January 27. Currently it is not displayed for the operators.

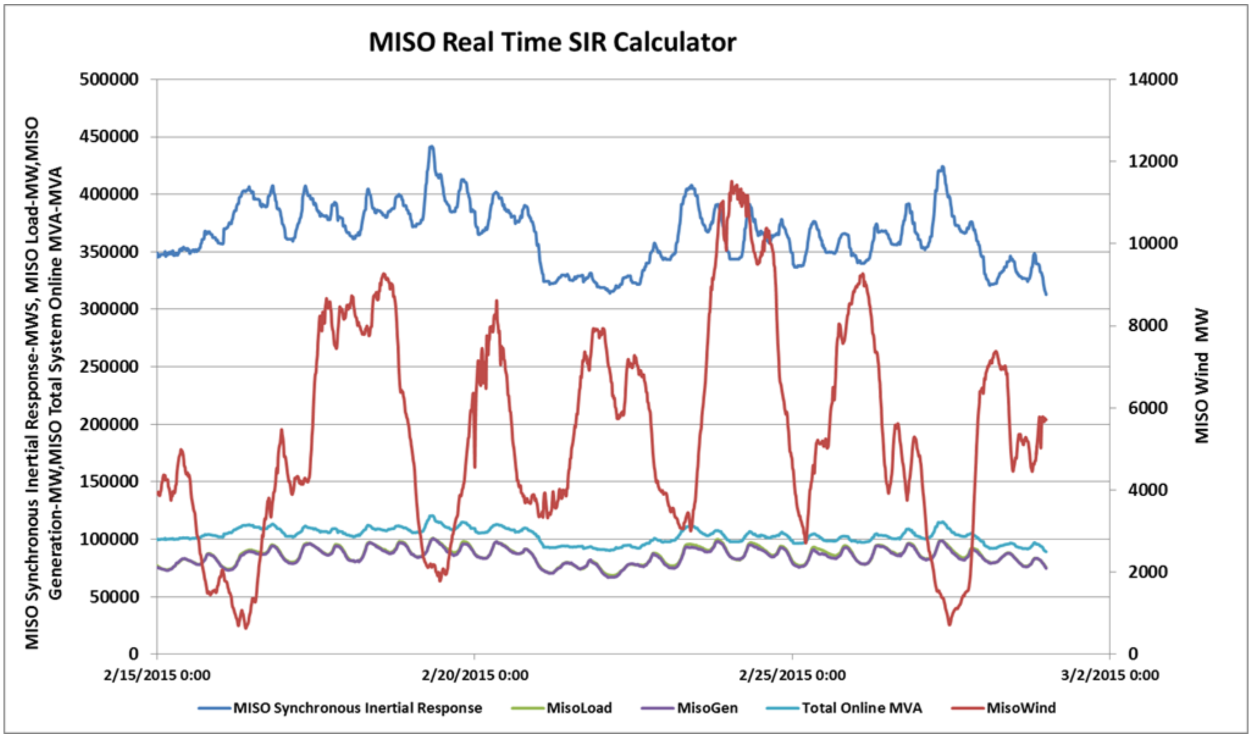


Figure A.15: Real-time SIR Calculator in MISO

BC Hydro

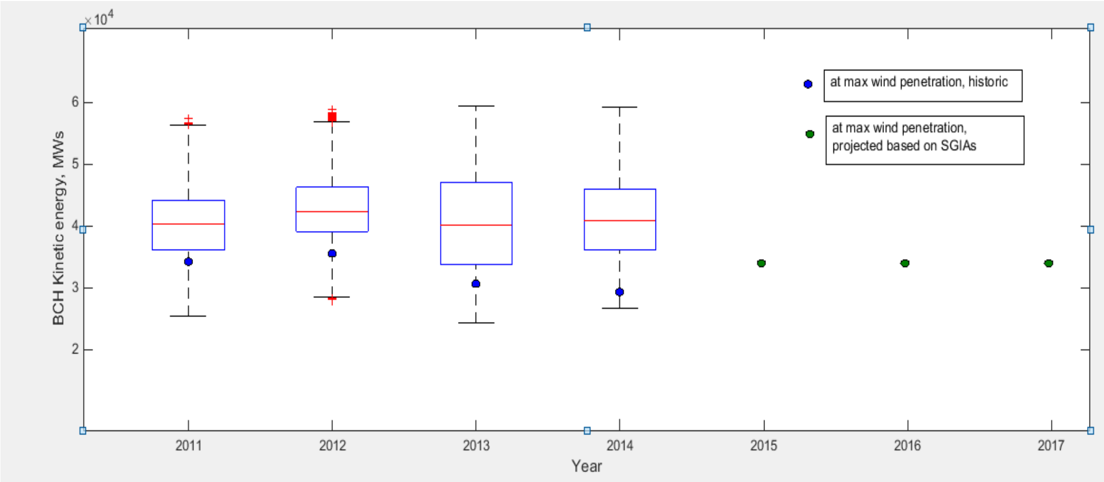


Figure A.16: Measure 3 for BC Hydro. Historic SIR Boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Blue dots correspond to peak nonsynchronous generation penetration hour in each year.

BC Hydro projected P_{load} is calculated as an average of historical P_{load} from 2011 through 2014.

Table A.11 Supporting Data for Measure 3 Analysis

	2011	2012	2013	2014	2015	2016	2017
Installed Wind Capacity (P_{wind_inst}), MW	246	388	388	487	487	487	667
Supporting Data at max nonsynch penetration hour; i.e., an hour with maximum P_{wind}/P_{load} ratio							
P_{wind}/P_{load}	5 % (Apr)	6% (Nov)	9% (Apr)	13 % (Sep)	9%	9%	12%
P_{wind}, MW	199	302	330	336	336	336	460
P_{wind}/P_{wind_inst}	81%	78%	85%	69 %	69%	69%	69%
BCH Load, MW (excluding AC import/export)	5,422	5,584	4,914	4463	N/A	N/A	N/A
P_{load} (including AC import), MW	3,938	5,075	3,731	2542	3,822	3,822	3,822

Duke

Duke Energy (Duke) has three separate BAs: Duke Energy Florida (DEF), Duke Energy Carolinas (DEC), and Duke Energy Progress (DEP). For all three Duke Energy areas there is no HVDC export/import capacity, and imports at any hour are zero. All three are part of the Eastern Interconnection and all ties to neighbors are ac.

Duke has been employing variations of these measures for some time and sees promise in them as reliability metrics. Duke intends to refine the data and analyses and has already identified potential improvements in data collection and analysis, and in the measures themselves.

Duke's BAs have varying generation composition and load characteristics, but none currently has or is forecast to have significant penetrations of nonsynchronous generation (NSG) as compared to CAISO and ERCOT. In particular, DEF has no NSG (quantifiable at the bulk level), and none is projected in the coming three-year time frame. Both DEC and DEP have experienced a dramatic rise in NSG (almost completely PV solar) over recent years due to state incentives (in addition to federal ones), but penetration is expected to flatten as the state incentives expire. This impending expiration also drove some apparent anomalous historical results due to significant increases in NSG installation/operation in December of each year.

As Duke continues to refine data collection and analysis for these measures, it is expected that other anomalies will be identified and resolved.

DEF Statistical Analysis of Kinetic Energy and Projected Minima

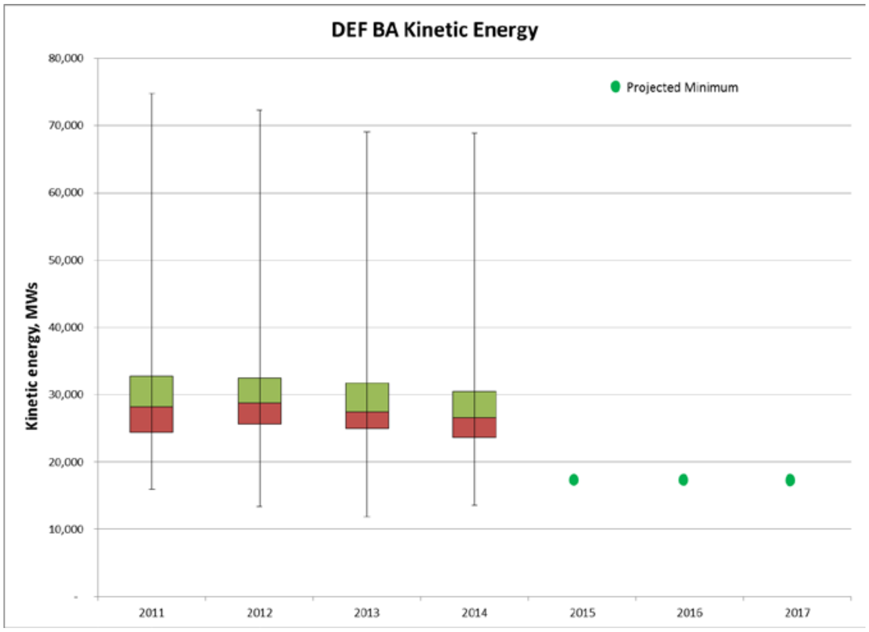


Figure A.17: Measure 3 for Duke Energy Florida. Historic SIR boxplots and future projections of SIR at minimum load.

Note, DEF currently has no measurable NSG penetration and doesn't project any. The future minimum projections of kinetic energy for DEF are based on the lowest value observed over the 2011–2014 time period due to the lack of nonsynchronous generation. Since there is no nonsynchronous generation in DEF, the projected KE minima do coincide closely with load minima.

DEC Statistical Analysis of Kinetic Energy and Projected Minima

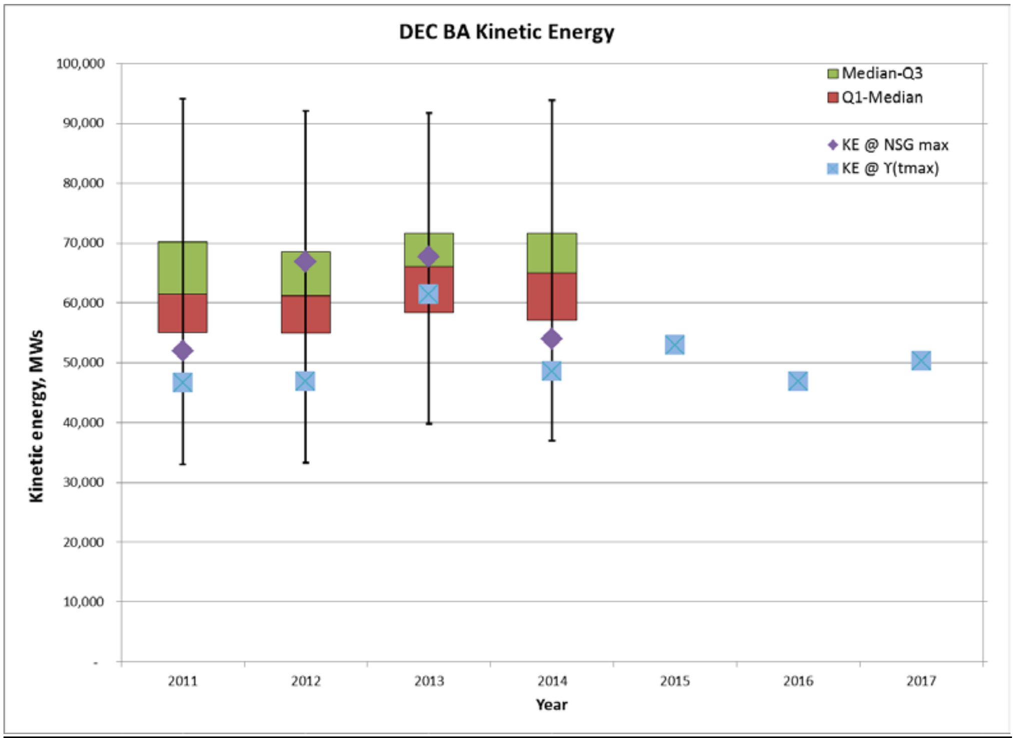


Figure A.18: Measure 3 for Duke Energy Carolinas. Historic SIR boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Purple dots correspond to peak nonsynchronous generation penetration hour in each year. Blue dots correspond to hours with maximum nonsynchronous to synchronous generation ratio.

For DEC, actual BA loads were not used in the analysis. The understood intent of the analysis was to use total BA generation (i.e., BA load net of imports/exports) as the basis for calculation. The purple dots on Figure A.18 are kinetic energy at maximum production from nonsynchronous generators, kinetic energy at NSG max (historical only). Since practically all of the NSG in DEC is solar, kinetic energy at max NSG max, usually at a time when load is near peak and synchronous generation on-line is high as well (12:00–14:00 local time, depending on time of year). The blue dots (kinetic energy at ϒ(tmax)) correspond to kinetic energy at the maximum ratio of nonsynchronous to synchronous generation (NSG/SG) occur and are not at the same time as NSG peak.

The growth in total synchronous generation is projected using the forecast growth in peak BA load as a percentage of the forecast 2014 peak (an average of approximately 1.35 percent per year).

Table A.12 Supporting Data for Measure 3 Analysis							
	2011	2012	2013	2014	2015	2016	2017
Installed PV Capacity (P_{PV_inst}), MW	48	107	121	136	214	239	232
Supporting Data at max wind penetration hour; i.e., an hour with maximum P_{PV}/P_{SG} ratio							
P_{PV}/P_{SG}	0.2%	0.3%	0.7%	1.2%	1.6%	2.1%	1.7%
P_{PV}, MW	15	25	70	99	147	166	161
P_{PV}/P_{PV_inst}	30.7%	23%	57.8%	73.1%	69.1%	69.6%	69.6%
P_{SG}, MW	9,083	7,847	10,551	8,323	9,262	7,877	8,664

DEP Statistical Analysis of Kinetic Energy and Projected Minima

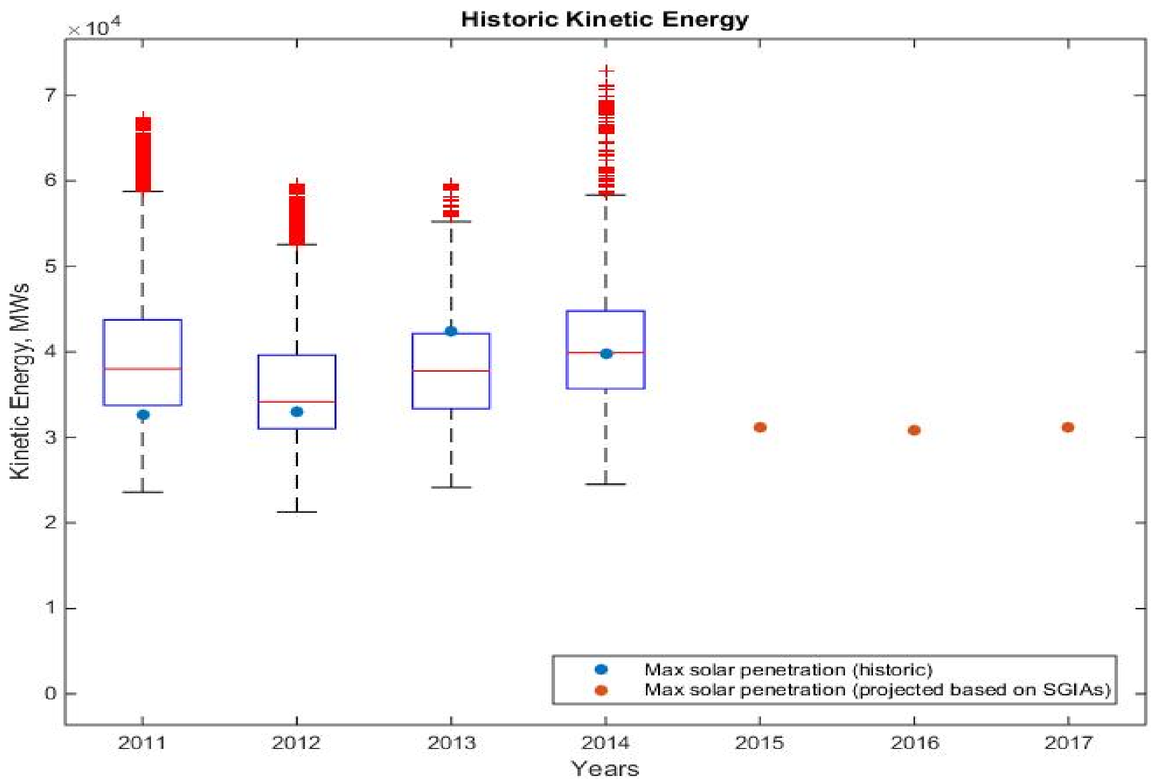


Figure A.19: Measure 3 for Duke Energy Progress. Historic SIR boxplots and future projections of SIR at peak nonsynchronous generation penetration hour. Blue dots correspond to peak nonsynchronous generation penetration hour in each year.

Table A.13 Supporting Data for Measure 3 Analysis							
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Installed PV Capacity (P_{PV_inst}), MW				320	447	712	712
Supporting Data at max wind penetration hour; i.e., an hour with maximum P_{PV}/P_{load} ratio							
P_{PV}/P_{load}				3.4%			
P_{PV}, MW				222	309	495	495
P_{PV}/P_{PV_inst}				69.4%	69.1%	69.6%	69.6%
P_{load}, MW	6,352	6,431	7,681	6,558			

Southern

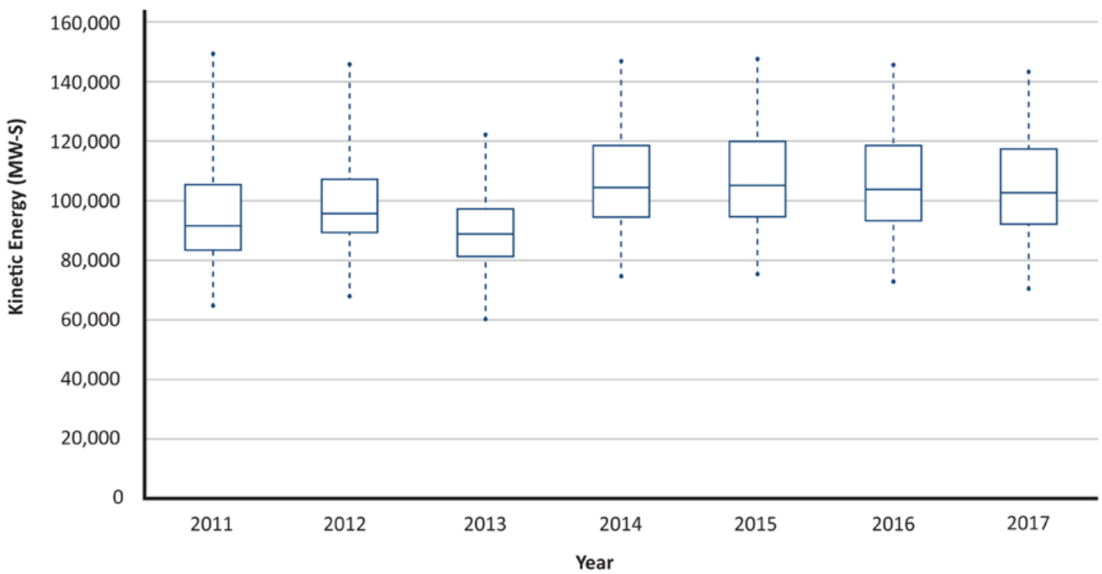


Figure A.20: Measure 3 for Southern Balancing Area historic and future projections.

Southern Company projected P_{load} is calculated as the average of historical P_{load} during 2011–2014.

Table A.14 Supporting Data for Measure 3 Analysis							
	2011	2012	2013	2014	2015	2016	2017
Installed Capacity Nonsynch (P_{NSG_inst}), MW	0	0	248	454	1586	1836	2324
Installed Capacity Wind (P_{wind_inst}), MW	0	0	202	404	404	654	654
Installed Capacity Solar (P_{solar_inst}), MW	0	0	46	50	1182	1182	1670
Supporting Data at max nonsynch penetration hour, i.e. an hour with maximum P_{NSG}/P_{load} ratio							
Nonsynch. gen. penetration peak, P_{wind}/P_{load}	0.0%	0.0%	0.3%	1.1%	1.1%	1.8%	1.8%
P_{wind}/P_{load}	0.0%	0.0%	1.1%	2.2%	2.2%	3.6%	3.6%
P_{wind}, MW	0	0	44	202	202	325	325
P_{wind}/P_{wind_inst}	0.0%	0.0%	21.8%	50.0%	50.0%	49.7%	49.7%
P_{solar}/P_{load}	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
P_{solar}, MW	0	0	14	0	0	0	0
P_{solar}/P_{solar_inst}	0.0%	0.0%	30.4%	0.0%	0.0%	0.0%	0.0%
P_{load}, MW	17,637	16,691	17,974	18,422	18,422	18,422	18,422

Measure 4: Frequency Response at Interconnection Level

The following examples illustrate the proposed frequency response measures for ERCOT and the Eastern and Western Interconnections. For the reference to Point A, C, B, and C', Figures 1 and 2 from the main body of the report are repeated in this appendix:

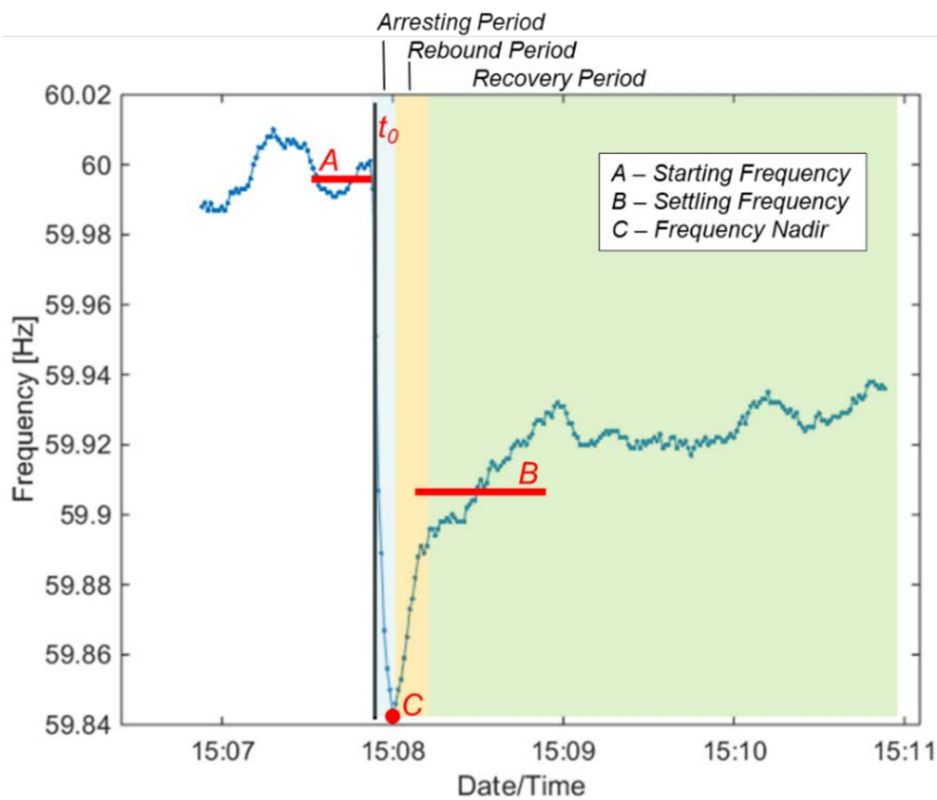


Figure A.21: Frequency response example for large disturbance in Western Interconnection

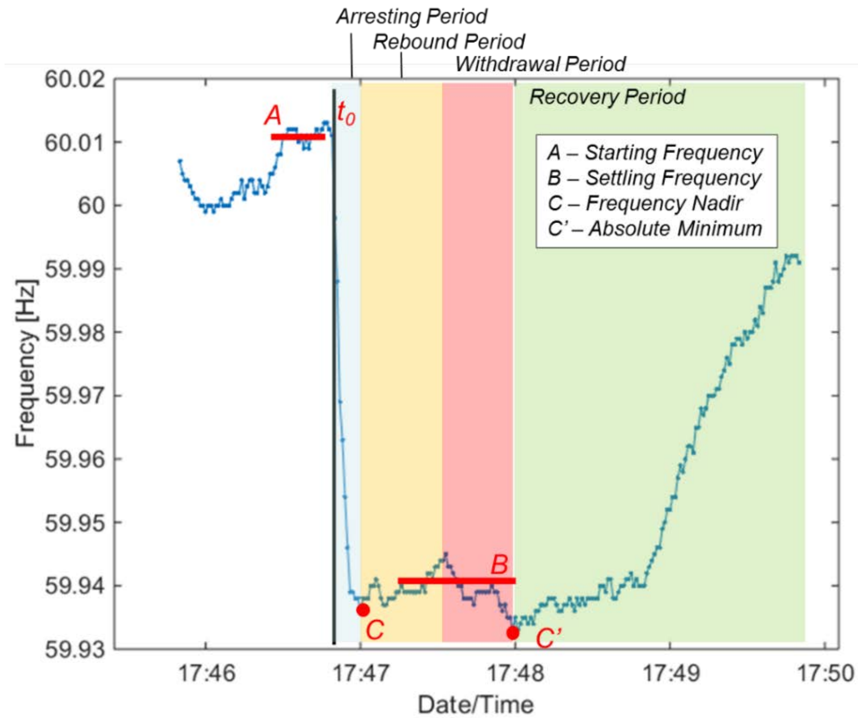


Figure A.22: Frequency response example for large disturbance in Eastern Interconnection (with governor withdrawal)

ERCOT Interconnection Example

The following plots illustrate some of the frequency response measures identified for trending.

A-to-B and A-to-C Frequency Response

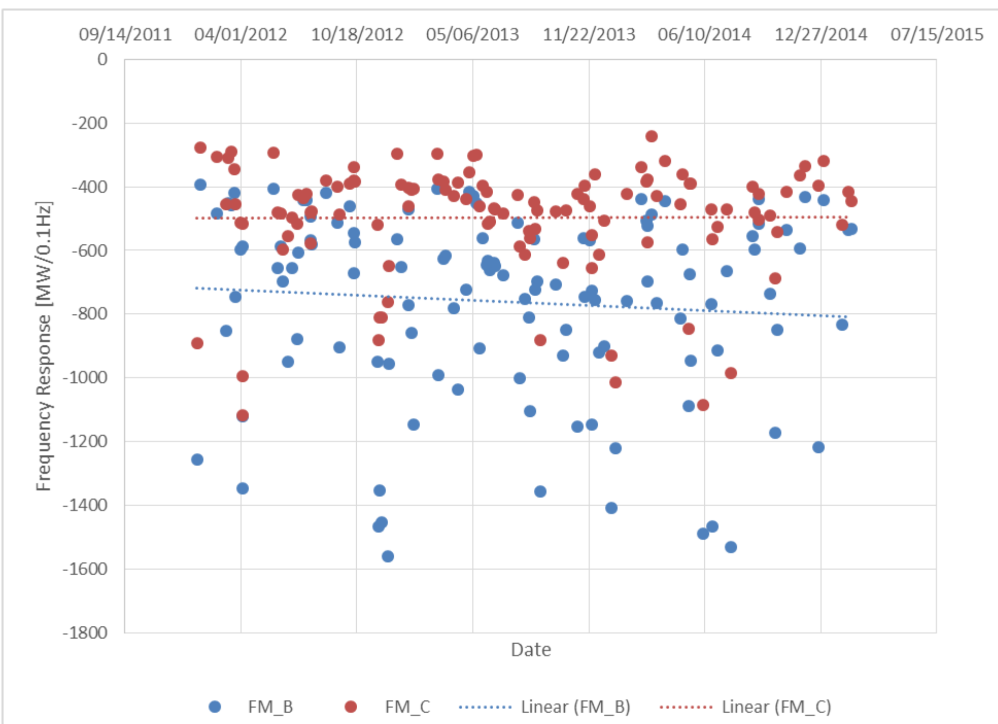


Figure A.23: ERCOT A-to-B frequency response (blue) and A-to-C frequency response (red)

Notice that the trend is toward an increasing absolute value of frequency response (frequency response is actually calculated as a negative number, since generation loss in megawatts in the measure calculation is taken with negative sign; hence larger negative numbers are better). The A-to-B frequency response is improving at a rate slightly better than A-to-C frequency response. This would indicate that there is some improvement in interconnection-wide governor response. Even though Measure 1 (synchronous inertia measure) is trending down due to increasing penetration of nonsynchronous generation, there is slight improvement over time in A-to-C frequency response. This can be explained by some improvements in governor response, which are listed below:

- During transition from zonal to nodal market, extensive governor testing was done at all plants.
- Since March 2012, wind generators are also required to provide governor-like response. This response is faster than governor response from conventional generators. Governor-like response from wind generators is available for overfrequency events any time a generator is in operation and for underfrequency events when wind generators are curtailed. Until completion of the CREZ transmission project (at the end of 2013), wind generation in western Texas was oftentimes curtailed and therefore capable of governor-like response at underfrequency events.
- On January 16, 2014, the BAL-001-TRE standard was approved with an effective date of April 1, 2014, and an implementation plan of 30 months. However, during the development of the standard, many generators tested their governors with narrower governor deadband settings, as prescribed by the standard, and then did not revert to the original settings. Consequently, implementation of the new governor requirements has been accelerated.

If data is available, trending frequency response measures (A to C and A to B) year to year versus trending only system conditions can provide additional insights concerning primary frequency response levels and characteristics. As an example, Figure A.24 shows A-to-C frequency response as a function of system net demand (load minus wind generation) for ERCOT. While Figure A.23 shows slight overall improvement over time in A-to-C frequency response, Figure A.24 provides additional insight, showing in 2013–2014 compared to earlier years the reduction in absolute frequency response at low net demand (due to reduction in synchronous inertia) and improvement at high net demand (due to improvements in governor response described above).

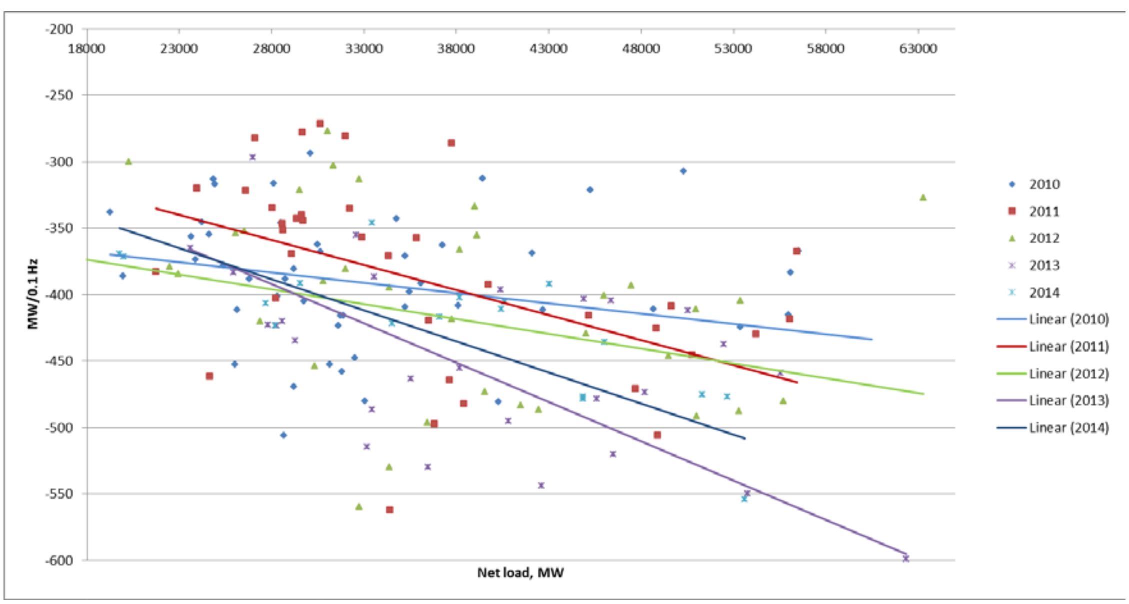


Figure A.24: A-to-C frequency response versus net demand in ERCOT 2010–2014

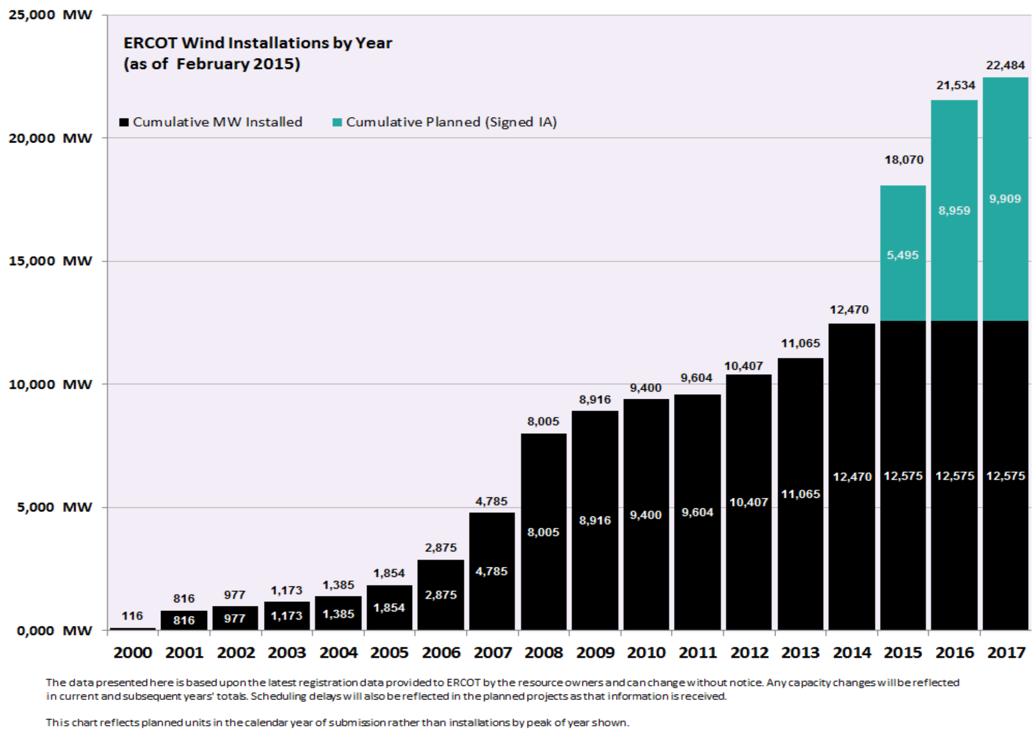


Figure A.25: ERCOT wind generation installations by year (as of February 2015)

Eastern Interconnection Example

The following plots illustrate some of the frequency response measures identified for trending.

A-to-B and A-to-C Frequency Response

Notice the trend toward increasing absolute value of frequency response (frequency response is actually calculated as a negative number; hence, larger negative numbers are better). It is observed from mid-2011 to mid-2014 that the A-to-B frequency response value is improving at a rate slightly better than A-to-C frequency response. This would indicate that there is some improvement in interconnection-wide governor response, as well as a continued inertial and governor response to arrest frequency deviations.

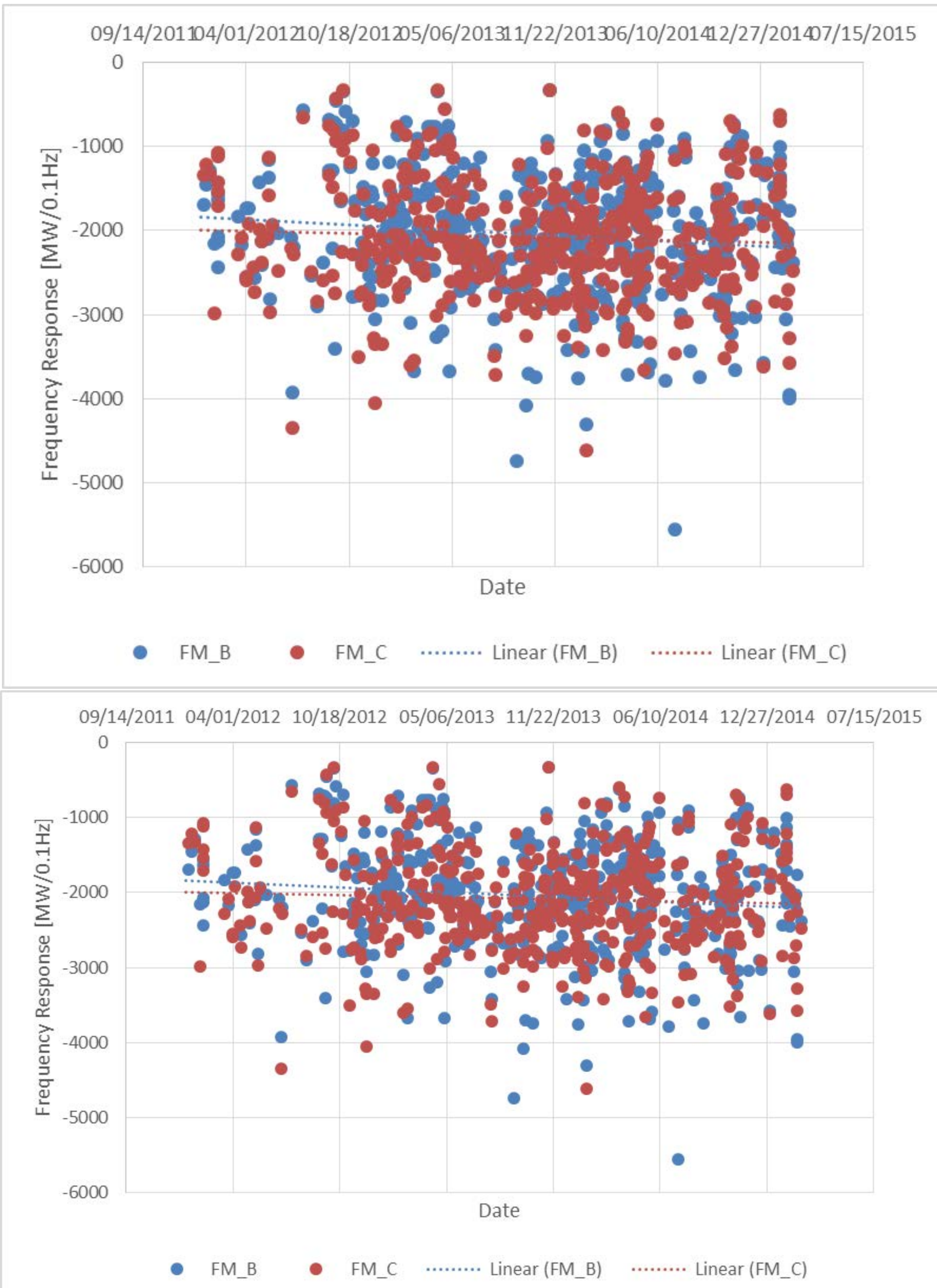


Figure A.26: Eastern Interconnection A-to-B frequency response (blue) and A-to-C frequency response (red)

C-to-B Ratio

The ratio between Point C and Point B in the Eastern Interconnection appears to be trending upward, meaning a larger difference between Points C and B. This either means the frequency nadir is dropping (which is not identified in the previous plots showing A-to-C and A-to-B frequency response measures) or the B value is improving. While this upward trend is a positive sign for reliability and frequency response, it is critical to note the number of data points with ratio < 1.0. This indicates events in which the frequency nadir is higher than the settling frequency calculated as Point B, indicative of the Eastern Interconnection "Lazy L" effect. Efforts put forth by NERC and industry regarding generator governor settings are likely to improve this ratio moving forward, and it is critical to track this measure in conjunction with the A-to-C frequency response measure above.

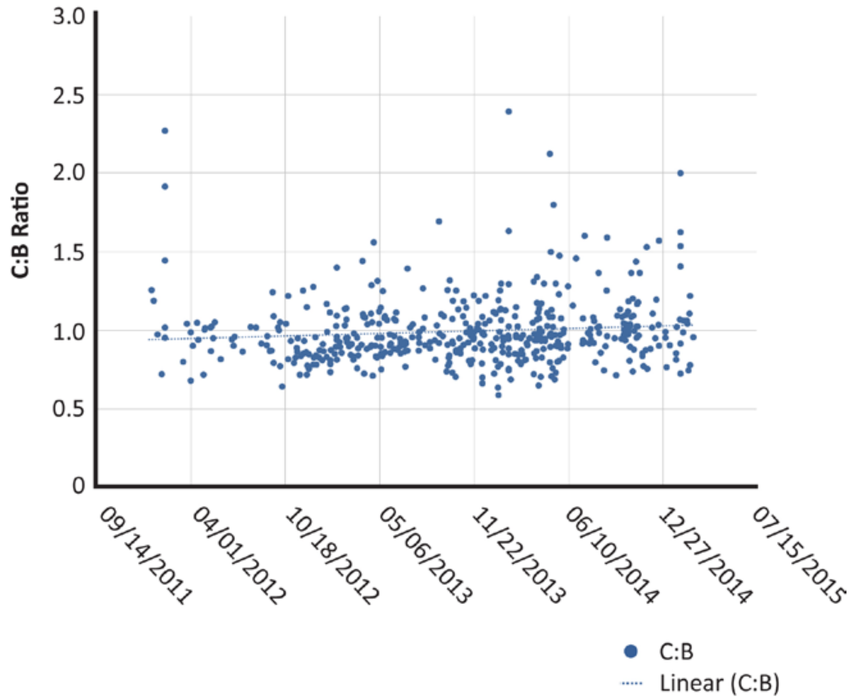


Figure A.27: Eastern Interconnection C-to-B ratio

C'-to-B and C'-to-C Ratios

The ratio of C' to B, if one exists, provides information relative to the extent of governor withdrawal following a frequency excursion event and initial governor response. C' only exists if a frequency minimum exists after the time period for calculating the B value. Hence, it may not exist for every event.

The ratio of C' to C provides similar information regarding the governor withdrawal; however, C' to C provides information relating to the severity of that withdrawal. Ratios larger than 1.0 signify events in which governor withdrawal results in frequency excursions lower than the initial frequency nadir. The goal is to correct the governor response withdrawal issue such that this ration is less than 1.0 and eliminated entirely.

The figure below trends C'-to-B and C'-to-C ratios over the time period of early 2012 to mid-2013. While this data does not cover the entire timespan of interest, it gives illustrative proof of concept regarding what information can be extracted from trending this measure year to year.

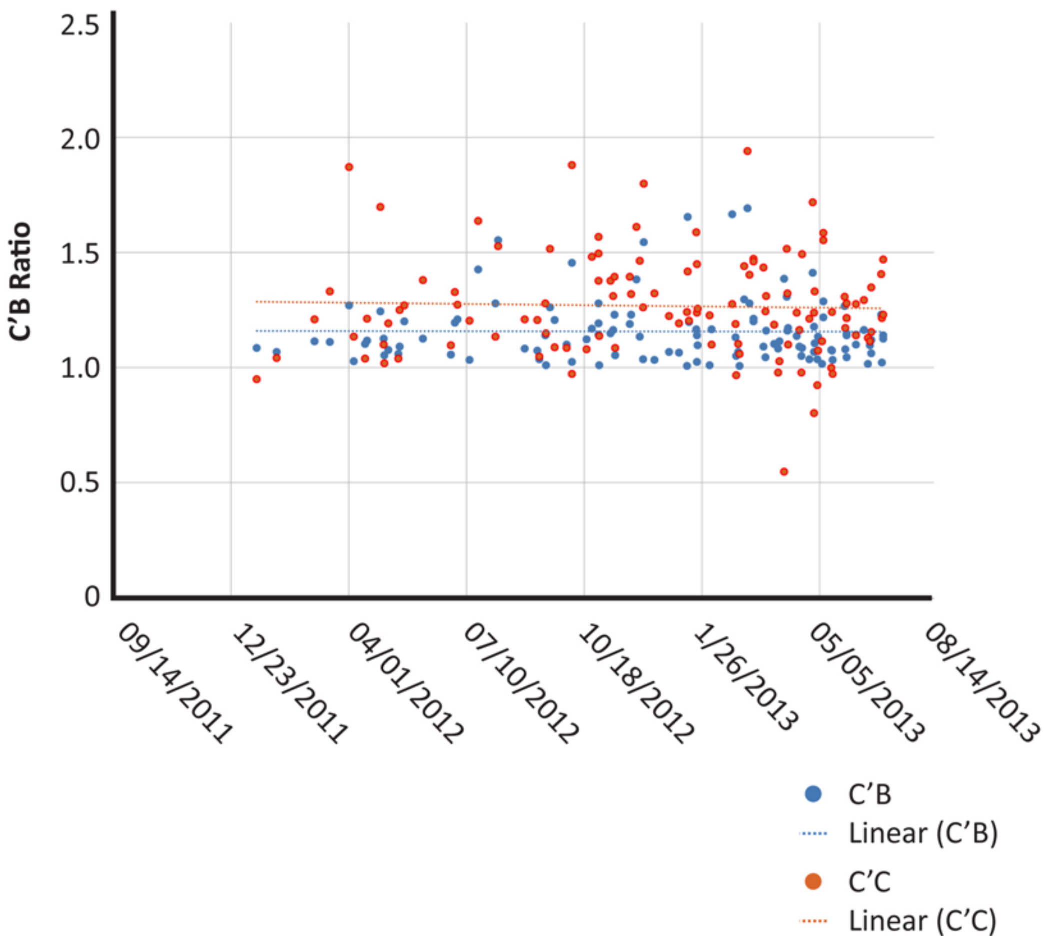


Figure A.28: Eastern Interconnection C'-to-B and C'-to-C ratios

Time-Based Measures

t_C-t_0 Measure

Time difference between the initial frequency nadir and time of event provides information regarding system inertia and governor response arresting frequency decline. The figure below shows chronological trend of this time difference. It is important to note that the time range of t_0 to t_0+12 seconds is used to calculate the frequency value. The figure below shows that this time window may not fit all frequency events in the Eastern Interconnection as many data points hit the upper time limit. Also note that this information is calculated from raw data and needs further investigation to filter out outliers. However, the proof of concept demonstrates the capability to trend this time difference chronologically.

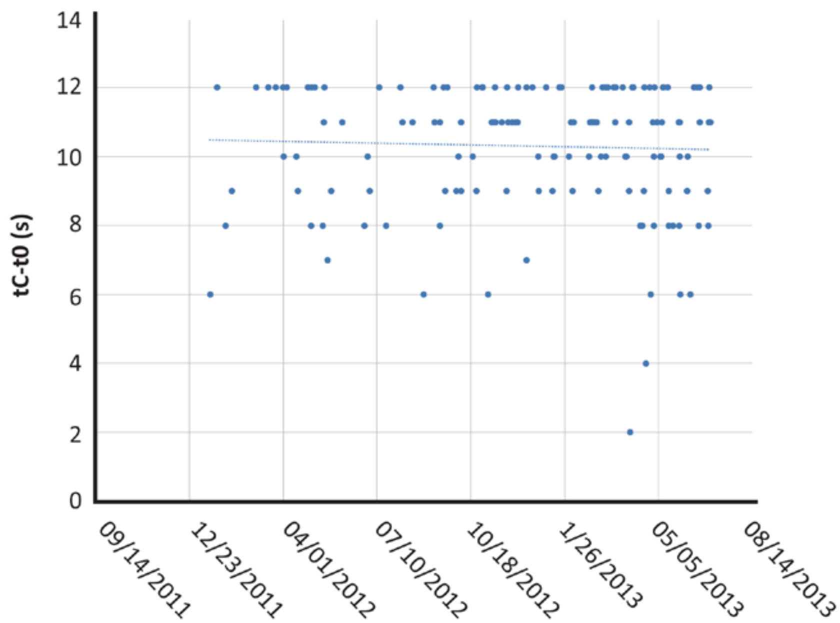


Figure A.29: Eastern Interconnection t_C-t_0 time-based measure

$t_{C'}$-t_0 and $t_{C'}$-t_C Measures

Time difference calculations to the C′ frequency point provide information regarding governor withdrawal and its duration and impact. The figure below shows consistency in duration over the timespan observed in the Eastern Interconnection.

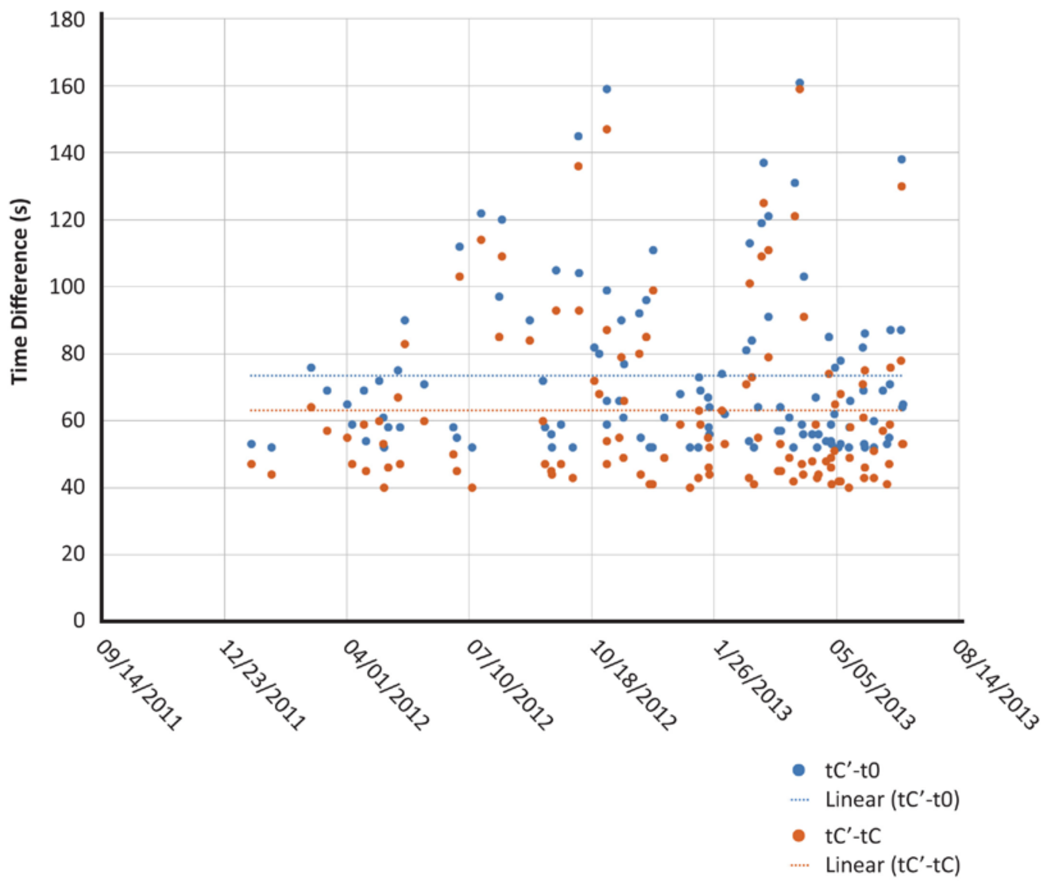


Figure A.30: Eastern Interconnection $t_{C'}$-t_0 (blue) and $t_{C'}$-t_C (orange) time-based measures

Western Interconnection Example

The following plots illustrate some of the frequency response measures identified for tracking.

A-to-B and A-to-C Frequency Response

The Western Interconnection is seeing improved frequency response from the time period of mid-2011 to mid-2014. The data suggests that A-to-B frequency response and A-to-C frequency response track similarly. This also indicates improved interconnection governor response to frequency deviations.

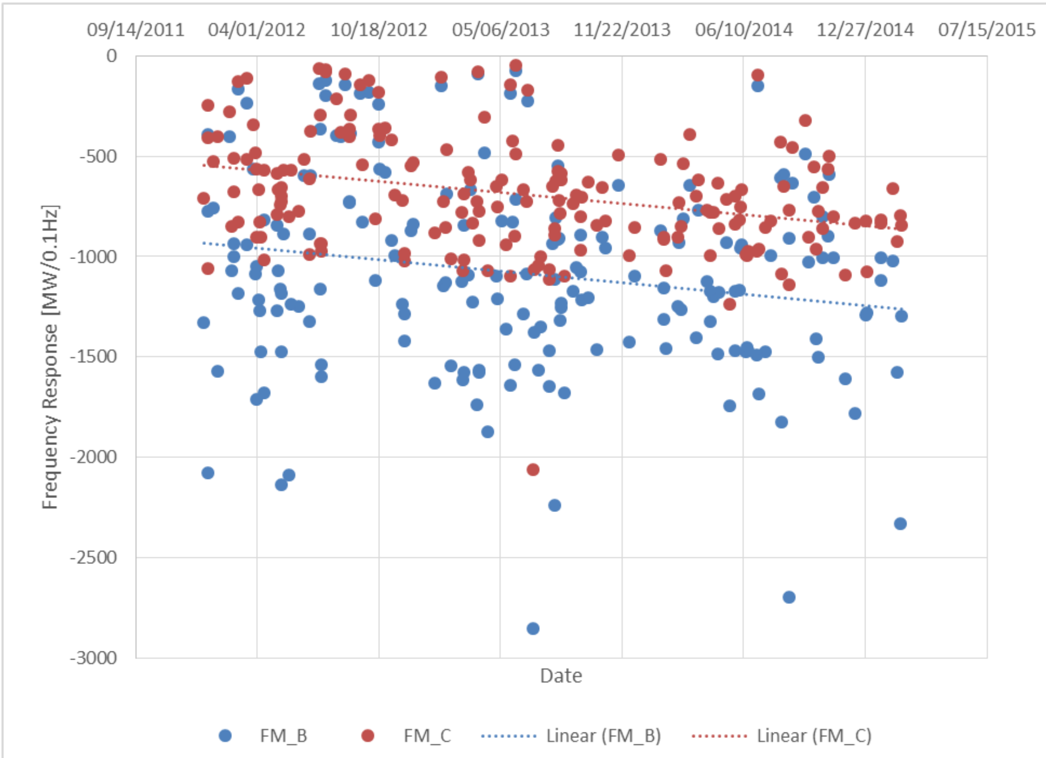


Figure A.31: Western Interconnection A-to-B frequency response (blue) and A-to-B frequency response (red)

C-to-B Ratio

The Western Interconnection is experiencing a slight decline in the ratio from Point C to Point B, meaning the difference in frequency value between Point B and Point C is declining slightly. Note that this proof of concept figure may be skewed to outliers that need further investigation. However, the concept of the C-to-B ratio declining indicates either a decrease in frequency response (not likely, due to a strong response from the frequency response calculation above) or the frequency nadir is increasing, meaning a reliability benefit and movement away from UFLS set points.

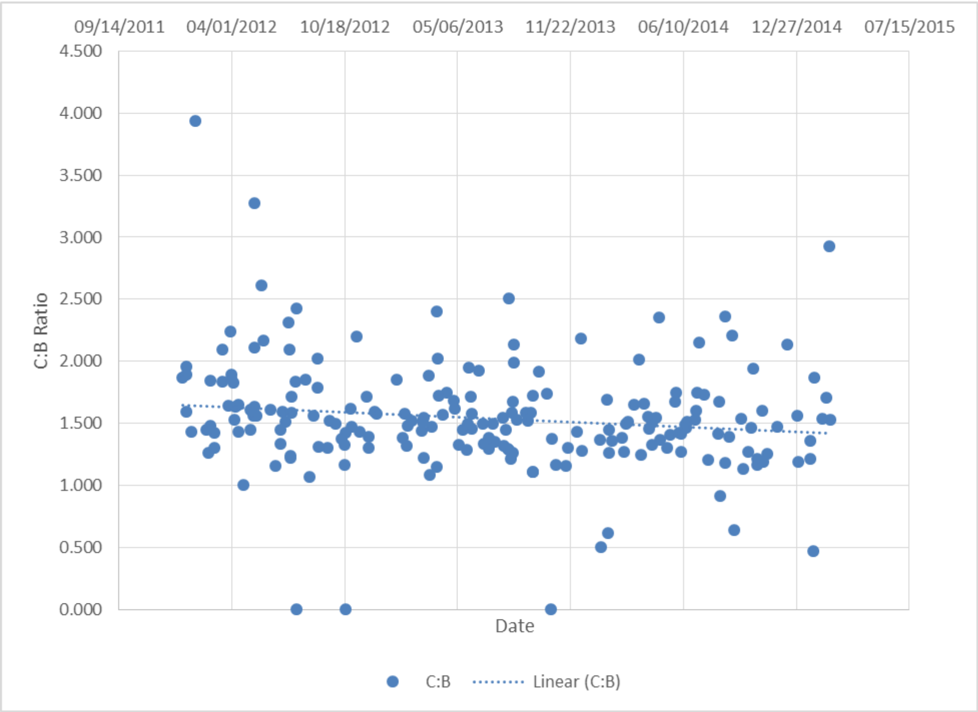


Figure A.32: Western Interconnection C-to-B ratio

C'-to-B and C'-to-C Ratios

The Western Interconnection does not generally have a C' value. Therefore, C' measures are not trended over time.

Time-Based Measures

tC-t0 Measure

Time-to-frequency nadir in the Western Interconnection (WI), though less data is available for this measure in the WI, demonstrates a relatively stable trend in inertia and frequency response arresting declining frequency. Average time difference is trending around approximately 7.5 seconds.

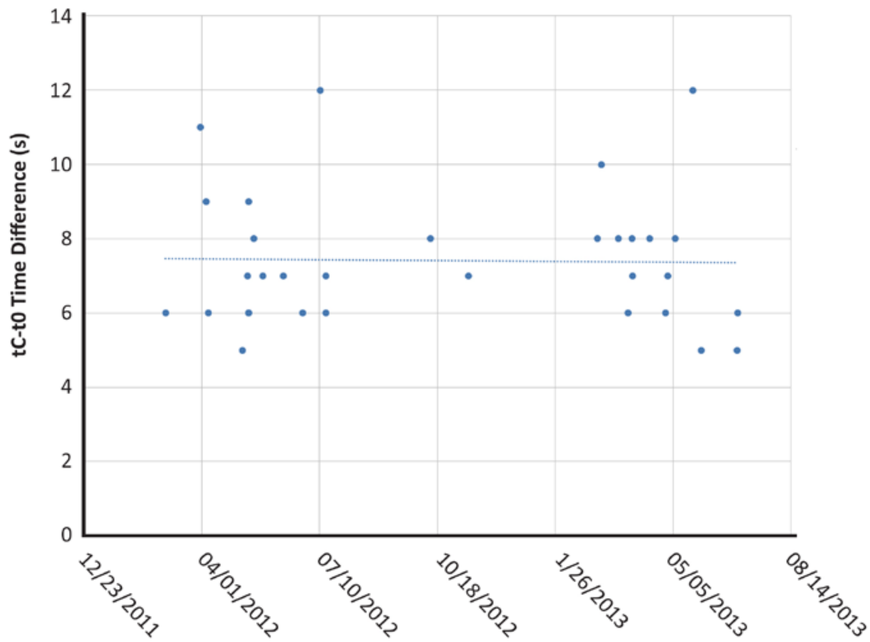


Figure A.33:.Western Interconnection tC-t0 time-based measure

tC’-t0 and tC’-tC Measures

With no C’ frequency point for the Western Interconnection, there is no associated tC’ value and hence no calculation of these time-based measures.

Appendix B – Net Demand Ramping Variability

The changes to the generation mix and other energy and environmental policies are imposing operational constraints on conventional resources. On the demand side, changes are also occurring, and predicting demand in the day-ahead time frame is becoming more of a challenge due to energy efficiency, distributed solar PV, more variable loads, and plug-in electric vehicles. Demand response and price-responsive loads are providing system operators with additional system-balancing tools.

In order to maintain load-and-supply balance in real time with higher penetrations of variable supply and less-predictable demand, BAs are seeing the need to have more system ramping capability, whether by adding more flexible resources within their committed portfolios or by removing system constraints to flexibility. Flexible resources, as described in this section, refer to dispatchable conventional as well as renewable resources, energy storage devices, and dispatchable loads.

To identify system ramping capability needs, the ERSTF studied data using a simple "net demand" terminology to illustrate the expected variability of the system, assuming there is no curtailment of variable supply. The net demand is calculated by taking the difference between total load and total production from VERs. The Electric Power Research Institute (EPRI) recently published a technical paper called *Metrics for Quantifying Flexibility in Power System Planning* that suggests other useful metrics.[15]

EPRI's Metric for Quantifying Ramping Capability

In response to utility and ISO needs to better understand flexibility requirements, EPRI has been developing metrics, methods, and tools to assist in assessing the operational flexibility of an electric system. These are complementary to other efforts at regulatory agencies, utilities, and consultancies. The EPRI work is described here to provide additional context on how operational flexibility requirements and the ability of the system to provide this flexibility can be measured. This effort is still under development and needs further testing on real systems before being used in utility/ISO practice. This information was presented to the ERSTF and is included here for reference.

A multilevel framework has been proposed with various levels of assessment corresponding to different levels of detail. The framework described is intended as additional analysis or modeling beyond existing planning processes and is mainly aimed at areas likely to have significant operational flexibility requirements. Higher-level screening should suffice for many areas, while the detailed methods may only be needed for those where flexibility has been identified as an issue.

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

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

In Level 3 of the EPRI approach, more detailed metrics are considered. These metrics are based on post-processing of operational simulations that may already have been carried out for a system or on historical data. Based on expected unit commitment for each interval of the time period studied, the flexibility available from each resource

[15] http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004243

can be measured for each hour of the study time frame. This is then compared to a flexibility requirement as defined in Level 1 to assess the sufficiency of the system to meet flexibility requirements. The requirement is normally based on the largest expected ramps up to a certain percentile under certain conditions. This results in three different flexibility metrics that can be assessed against system operations and can be calculated for both up and down ramping over different time horizons (typically five minutes to eight or more hours).

1. **Periods of Flexibility Deficit (PFD)**: The PFD is a measure of the number of periods when the available flexible resources were less than the assumed required flexibility. The required ramping is measured based on the type of analysis described elsewhere in this document. This is done over all time horizons. Deficits over shorter time periods can be mitigated by improved short-term forecasting capabilities, dynamic and probabilistic reserve procurement strategies, reserve sharing between connected systems, and new fast-start, high-response resources. Over longer time periods, such as three to eight hours, better long-term forecasts aid in the scheduling of large, slow-starting generation and intertie flows. In both cases, operational practices should be adopted first, but if there is still a flexibility deficit, new resources may be required.

2. **Expected Unserved Ramping (EUR):** EUR measures the amount of ramping that is not met for the system simulated. It is important to recognize that this does not mean the system will be short that much energy, but that this is the cumulative amount of shortfalls for ramping requirements based on large ramps. For example, the 97th percentile of ramp may be used, and the system may be short 20 MW for meeting that ramp over a given time horizon.

3. **Insufficient Ramp Resource Expectation (IRRE):** IRRE is a measure of the frequency of flexibility shortfalls over different time horizons. It differs from PFD in that it uses a probabilistic approach to determine the likelihood of not being able to meet net demand ramps at each time interval. A distribution of ramps is created and compared to a distribution of available flexibility. This is similar to the loss-of-load expectation used in resource adequacy assessment but is adopted for operational flexibility.

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

These four levels of analysis are still under development and need further testing on real systems before being used in utility/ISO practice. The Level 3 metrics are data and modeling intensive and dependent on the assumptions made in the modeling of system operations. Therefore, they are suited to issues such as resource expansion and determination of how different resources provide flexibility. Many of the measures are not purely a reliability measure, and instead may focus more on efficiency and economics as to how systems can manage flexibility needs.

Measure 6: Net Demand Ramping Variability

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

Building the Forecast Variable Energy Resource Portfolio

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

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

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

Load Build-out

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

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

Wind Profile Build-out

Existing Resources

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

Future Study Year

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

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

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

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

Solar Profile Build-out

Existing Solar

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

Future Study Year

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

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

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

Using the one-minute load profile and the expected wind and solar one-minute production profiles, the BA can develop minute-by-minute net load profiles by subtracting the one-minute wind and solar profiles from the one-minute load profiles. The monthly one-hour and three-hour ramping needs can then be calculated by any of the three options outlined below. The maximum one-hour up and down ramping needs are determined by calculating the 99.8th percentile for up ramp and the remaining one-fifth percentile for down ramp change, respectively, within each consecutive 60-minute period. The maximum three-hour up and down ramping needs are determined in a similar manner using the largest ramp in each consecutive 180-minute period. As shown in Figure B.1, the maximum three-hour ramp can occur in less than three hours.

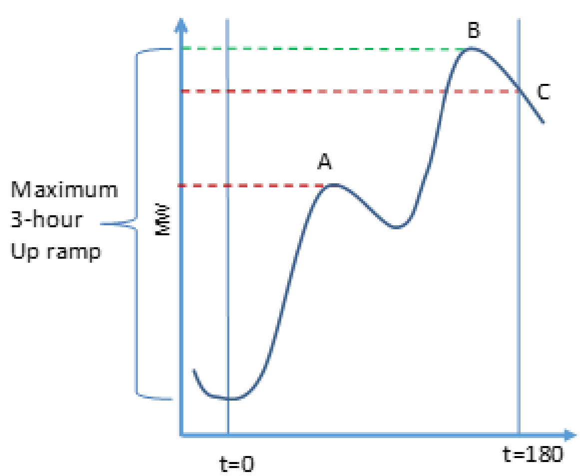


Figure B.1: Maximum three-hour ramp

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

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

Option 1 – One-minute moving window

- One-Hour Ramp: NL_{61}-NL_1, NL_{62}-NL_2, NL_{63}-NL_3....NL_{n+61}-NL_{n+1} ....n ≥0
- Three-Hour Ramp: NL_{181}-NL_1, NL_{182}-NL_2, NL_{183}-N_{L3}....NL_{n+180}-NL_n

Option 2 – Five-minute moving window

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

Option 3 – Average of one-minute moving window

- One-Hour Ramp or Three-Hour

  Up Ramp **=** Avg(NL_{t+4min}) ≥ Avg(NL_{t-4min})

  Down Ramp **=** Avg(NL_{t+4min}) < Avg(NL_{t-4min})

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

Defining the BA's Net Demand Ramping Variability

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

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

Where:

$Max[(3RR_{HRx})_{MTHy}]$ = Largest three-hour contiguous ramp starting in hour x for month y

E(PL) = Expected peak load

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

MTHy = Month y

MSSC = Most Severe Single Contingency

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

Results of Analysis by BA

CAISO

Table B.1: CAISO's Expected Build-out Through 2018					
	2011	2012	2013	2014	2018
Large-Scale Solar PV	182	1,345	4,173	4,512	6,202
Small-Solar PV		367	1,100	2,200	2,630
Solar Thermal	419	419	419	1,051	1,631
Distributed PV					2,400
Wind	3,748	5,800	5,894	5,894	8,557
Total					

The charts in Figures B.2 and B.3 show the one-hour and three-hour net demand ramping variability. As currently defined, the need is expected to increase for future years with the increase being more noticeable during the non-summer months. Figure B.2c shows the distribution of the one-hour up/down net demand ramping variability for 2011–2014 and the expected variability in 2018. Likewise, the charts in Figure B.3 show the distribution of the three-hour up/down variability for 2011–2018. The red shaded areas shown in Figures B.2c and B.3c represent two standard deviations from the mean of the one-hour and three-hour up/down variability, respectively.

CAISO's Historic Net Demand Ramping Variability Calculations and Trend for Future Projections

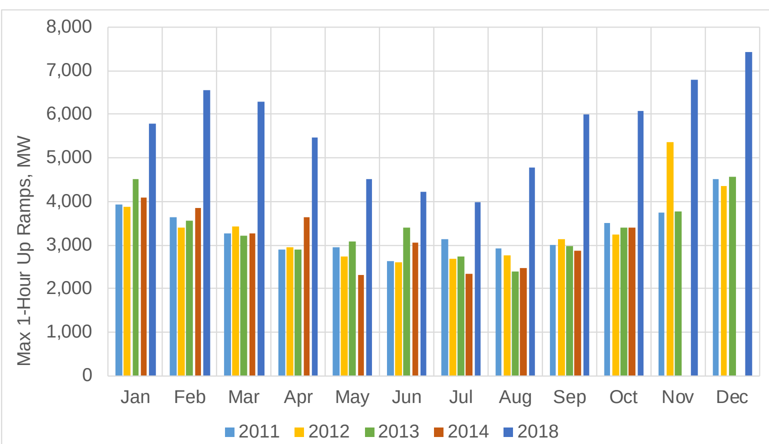


Figure B.2a: Maximum one-hour up ramp

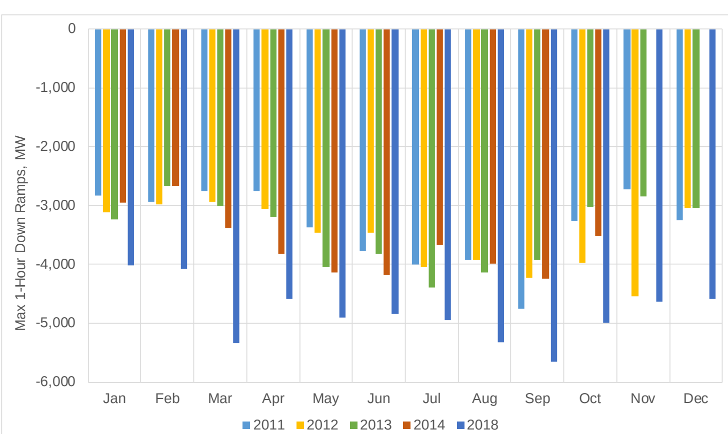


Figure B.2b: Maximum one-hour down ramp

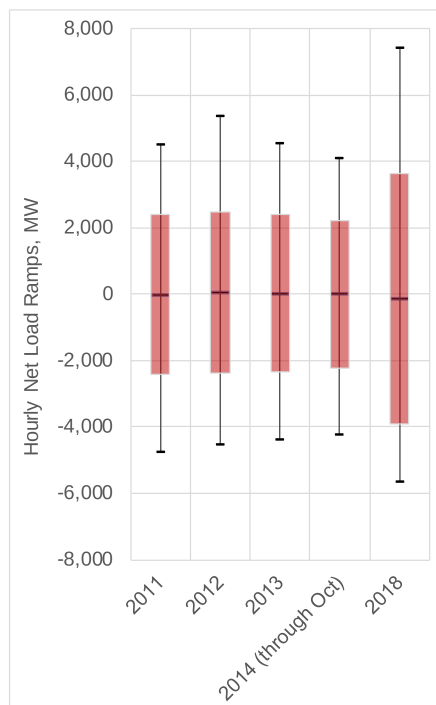


Figure B.2c: Yearly one-hour ramp distribution

Red shaded area represents 2 σ from the mean

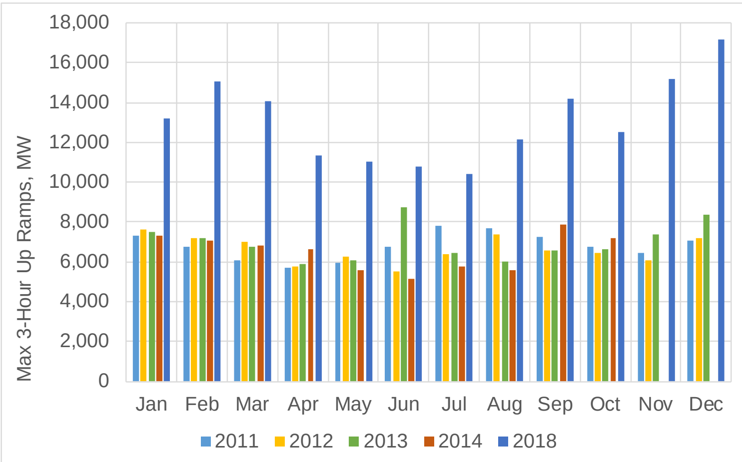


Figure B.3a: Max. monthly three-hour up ramps

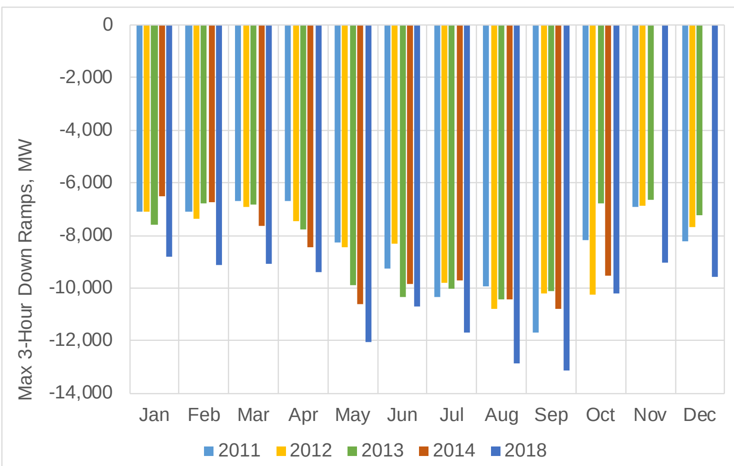


Figure B.3b: Max. monthly three-hour down ramps

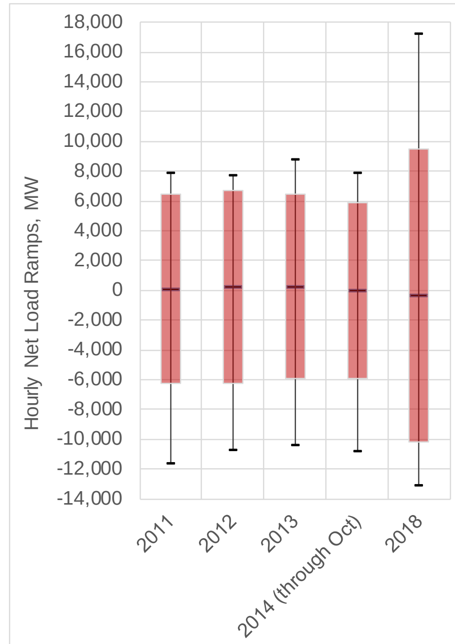


Figure B.3c: Yearly three-hour ramp distribution

Red shaded area represents 2σ from the mean

ERCOT

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

1. Total ERCOT system load with one-minute resolution for 2011–2014.
2. Total ERCOT wind power production with one-minute resolution for 2011–2014.
3. Total installed wind generation capacity for each year, 2011–2014,[16] Table B.2. In ERCOT, coastal wind is positively correlated with system load; therefore, the capacities are reported in the table as coastal and non-coastal wind to inform the analysis.

Table B.2 Installed Wind Generation Capacity for 2011–2014 and Projected Wind and PV Generation Capacity for 2018

Year	Wind Capacity, MW	Non-Coast Wind, MW	Coast Wind, MW	PV
2011	9,00	8,433	1,067	
2012	10,458	9,178	1,278	
2013	10,994	9,313	1,681	
2014	11,703	10,022	1,681	
2018	17,340 (with GIAs & FCs)			
2018 with PV	21,130 (with GIAs)			6,341 (Requests)

Calculation procedure and results

1. From historical load and wind generation data, net demand is calculated for every one-minute interval as load minus wind production.
2. One-hour and three-hour net demand ramps are calculated using one-minute moving window, Option 1, as described above.
3. In each studied year, find maximum of net demand up ramps and maximum net demand down ramps for every time frame (i.e., one hour or three hour), as 99.8th percentile and 0.2nd one-fifth percentile of net demand ramp distribution[17] (see Figures B.5–B.8). There is no particular trend in net demand ramps that can be observed based on historical data. This is partially due to the fact that installed wind generation capacity was only increasing by about 500 to 1000 MW a year. Also, it was observed that maximum load ramps are fairly close to maximum net demand ramp values, while maximum wind ramps are much lower (about one-half of maximum net demand ramps of one-hour ramps and about one-third of maximum net demand ramps for three-hour ramps). This means that the highest net demand ramps are “driven” by load ramps rather than wind ramps. The load ramps follow fairly constant diurnal patterns and are not expected to vary substantially from year to year.
4. Projected 2018 net demand ramps are based on projected installed capacity of variable generation (i.e., wind and solar) in 2018.

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

   - **2018 case:** The projected installed capacity of variable generation is based on planned projects with signed interconnection agreements and financial commitments.
   - **2018 with PV case:** The projected installed capacity of variable generation is based on planned wind projects with signed interconnection agreements and all solar projects that requested

[16] Note currently there is only 158.8 MW PV capacity registered with ERCOT.

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

interconnection with ERCOT. This goal of analyzing this case is to look at potential impacts from rapid solar build-out.

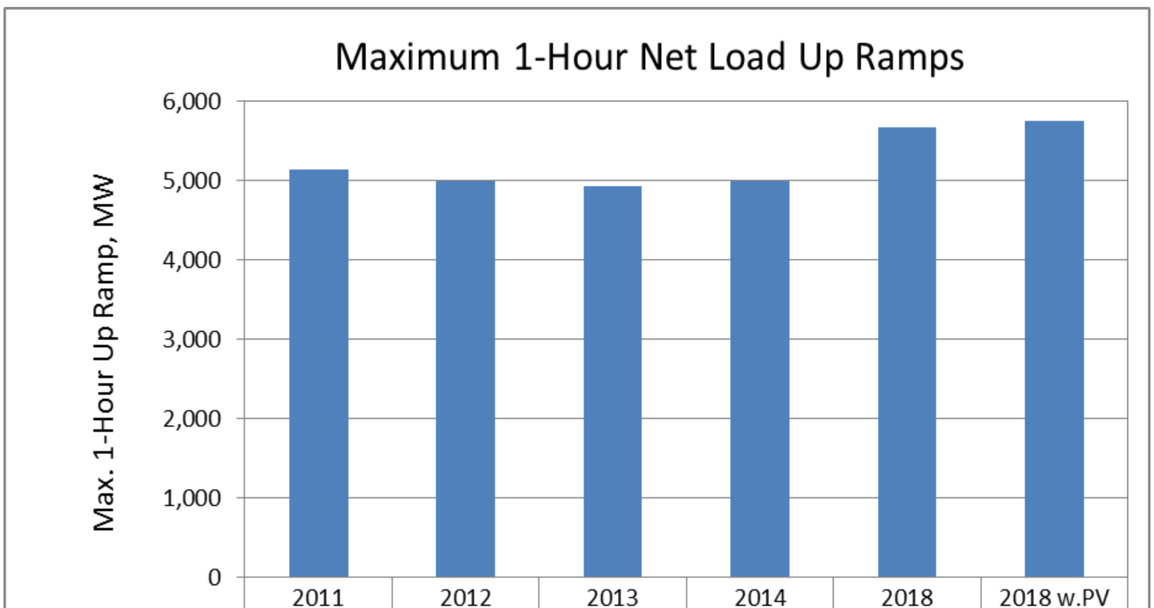
- Note that all wind interconnection requests in ERCOT currently add up to 24.5 GW of additional capacity, and ERCOT believes it is not realistic to assume that all of them will be built by 2018.

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

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

DNV GL (former KEMA) [18] developed the method for creating high-resolution variable power production and load time series from hourly data. The parameters for this method are derived from historically observed variability. This method was used to produce a time series with one-minute resolution for future load, wind, and solar generation.

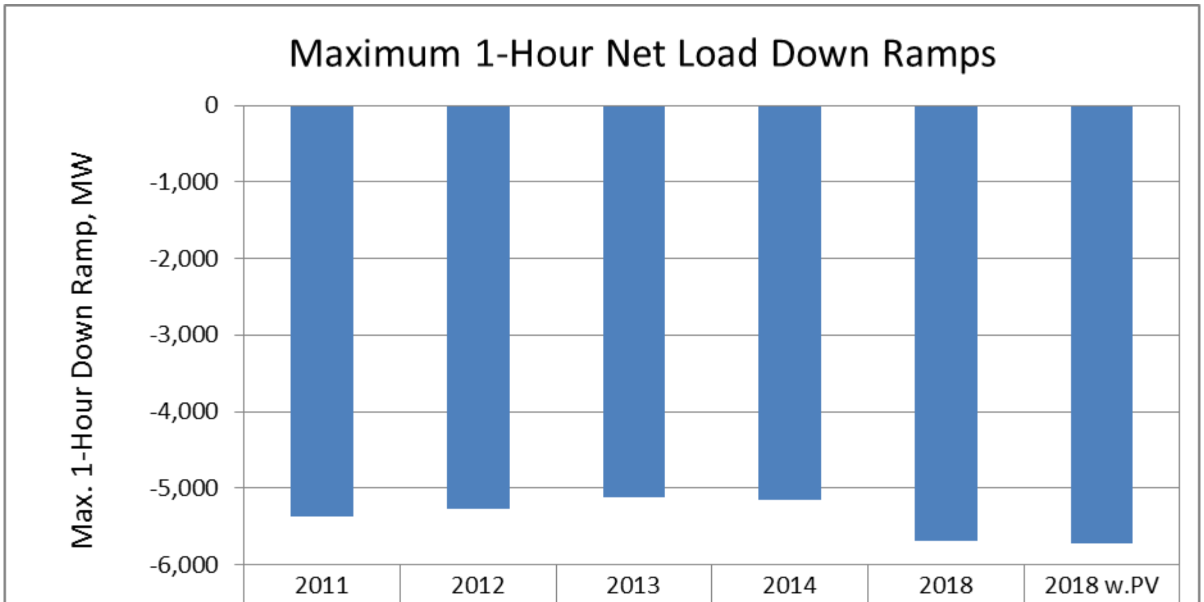
Figures B.4–B.6 show maximum net demand up ramps and maximum net demand down ramps for 2018 case and 2018 with PV case.



	2011	2012	2013	2014	2018	2018 w.PV
Max 1_Hr_Up	5,148	5,002	4,939	4,994	5,671	5,749

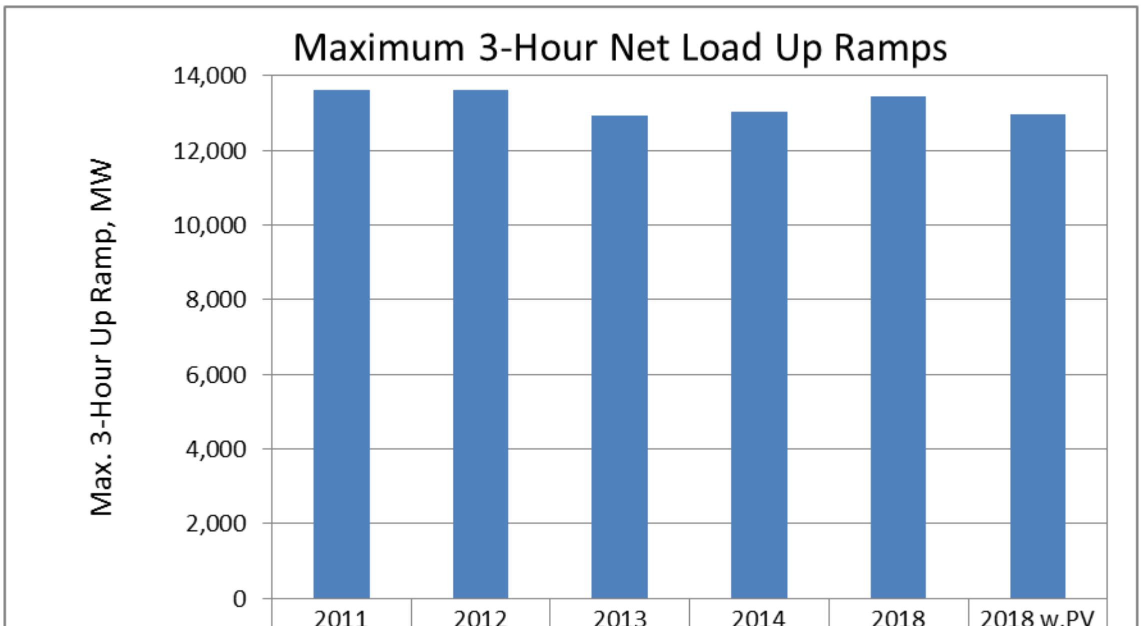
Figure B.4: Maximum (98th percentile) one-hour net demand up ramps 2011–2014 and projected for 2018

[18] http://www.dnvkema.com/Images/EndUseDataStrategy_July2014final.pdf



	2011	2012	2013	2014	2018	2018 w.PV
Max 1_Hr_Dn	-5,377	-5,265	-5,127	-5,152	-5,682	-5,729

Figure B.5: Maximum (0.2nd percentile) one-hour net demand down ramps 2011–2014 and projected for 2018



	2011	2012	2013	2014	2018	2018 w.PV
Max 3_Hr_Up	13,615	13,605	12,923	13,043	13,464	12,968

Figure B.6: Maximum (98th percentile) three-hour net demand up ramps 2011–2014 and projected for 2018

5. Figures B.7 and B.8 illustrate boxplots for one-hour and three-hour net demand ramps, respectively, for historical years 2011–2014 and future projections in 2018. Boxplots are a convenient way to compare net demand ramp statistics from several years on one plot.

   On a boxplot, each box represents one year of net demand ramps, as calculated in step 2 or step 3. On each box, the central mark (red line) is the median, the edges of the box (in blue) are the 25th and 75th percentiles, and the whiskers correspond to ± 2.7 sigma, which represents 99.3 percent coverage, assuming the data is normally distributed, and the outliers are plotted individually (red crosses). If necessary, the whiskers can be adjusted to show a different coverage.

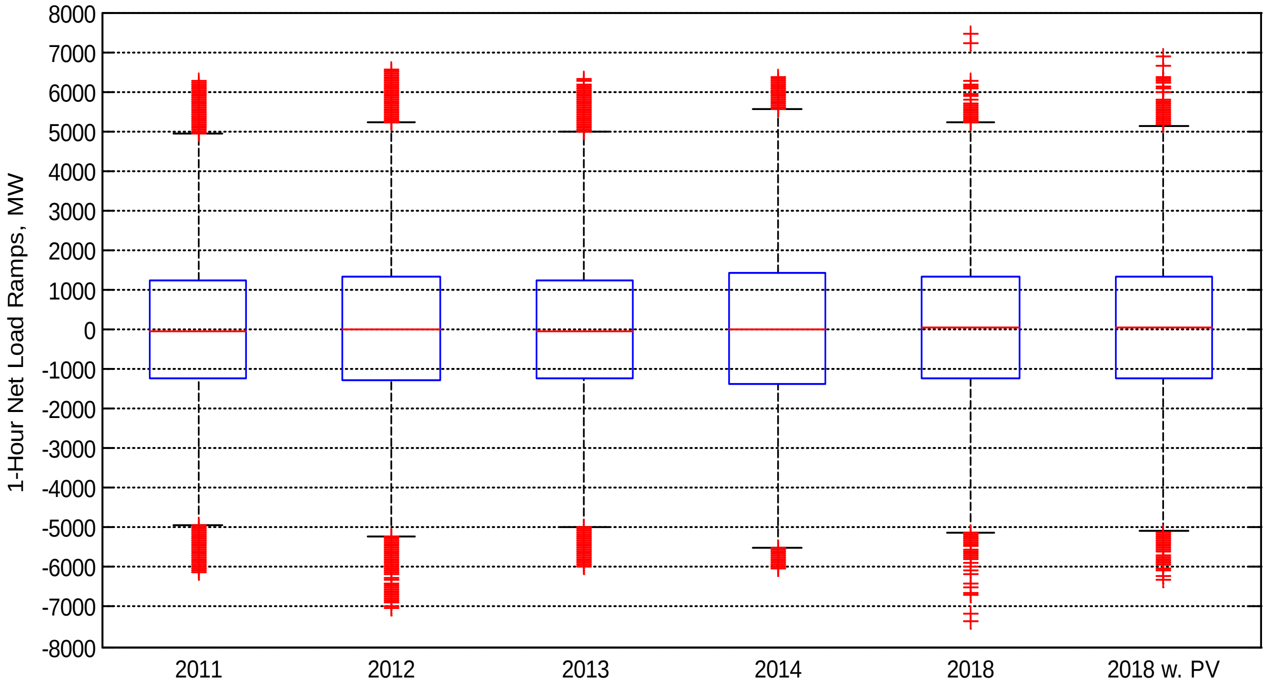


Figure B.7: Boxplots for one-hour net demand ramps 2011–2018

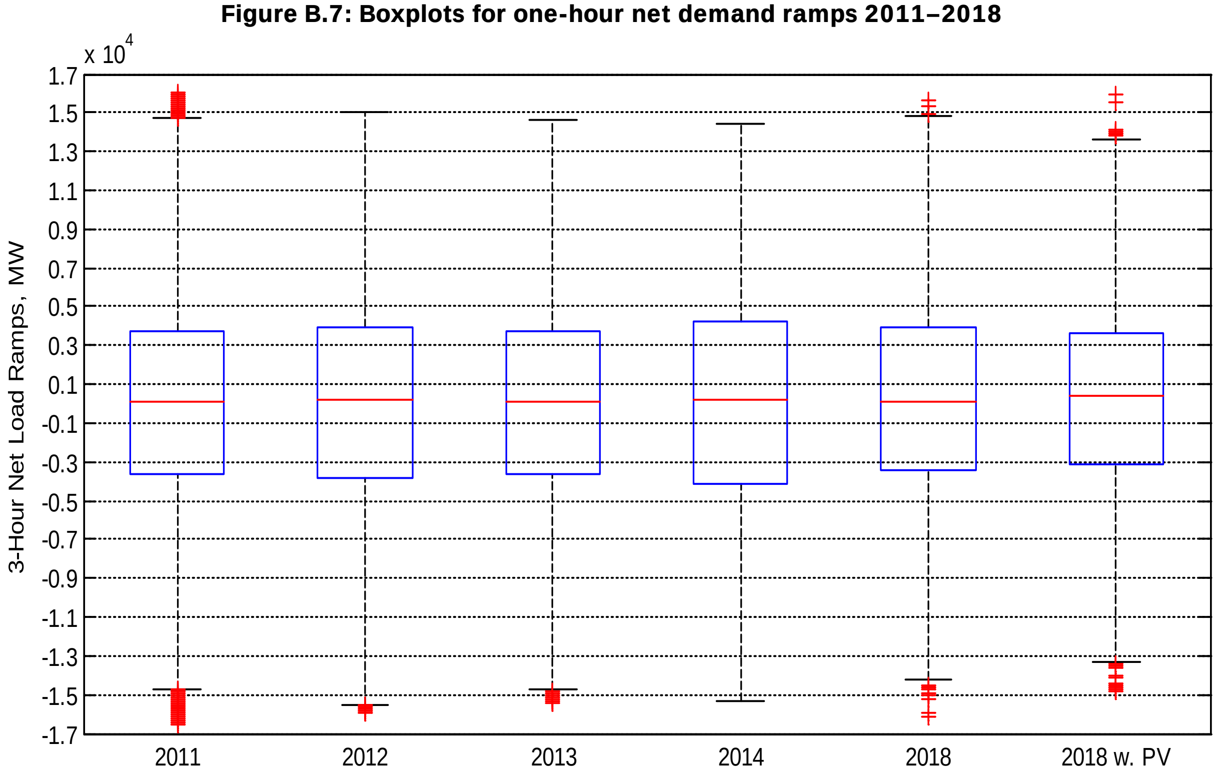
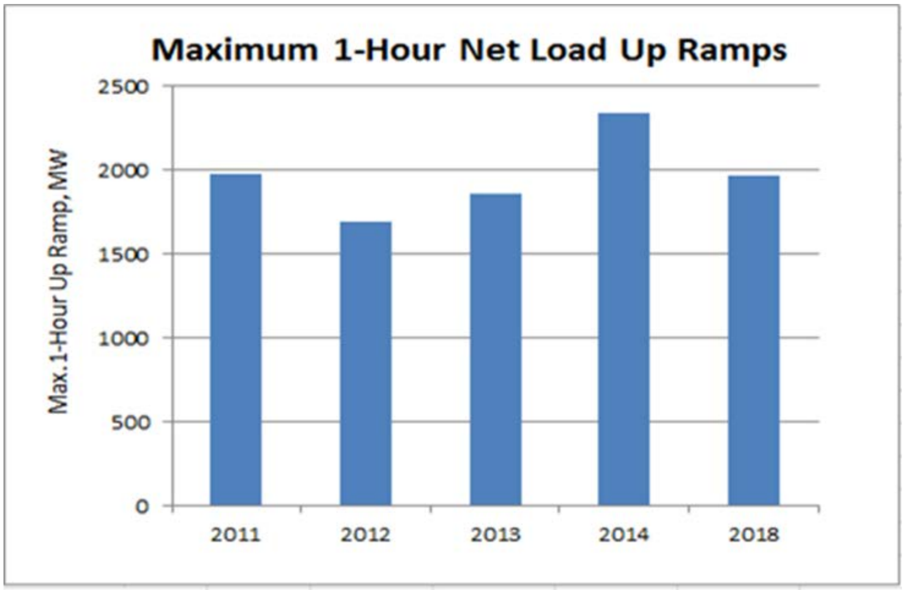


Figure B.8: Boxplots for three-hour net demand ramps 2011–2018

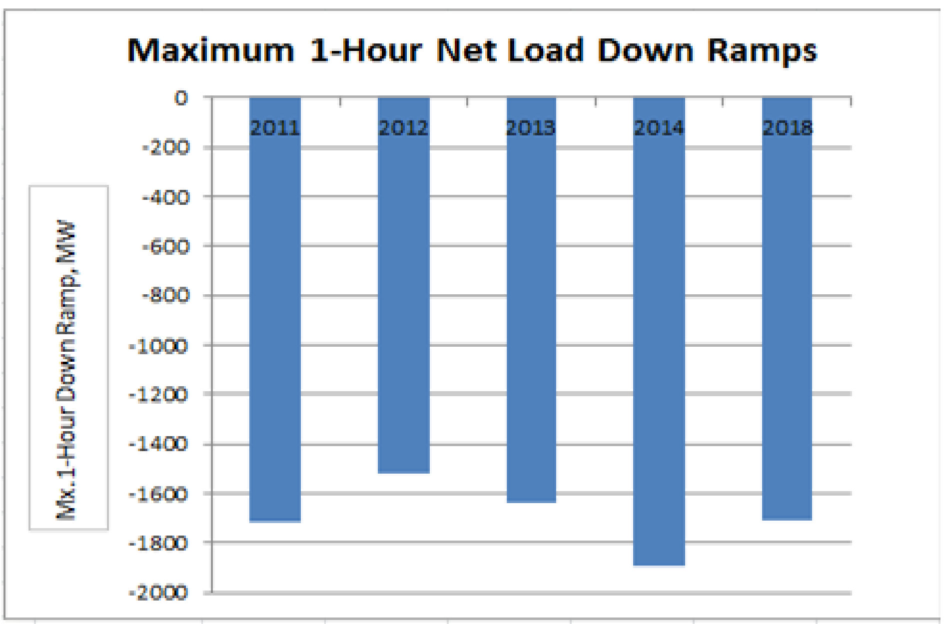
BC Hydro

By the end of 2014, BC Hydro had approximately 487 MW of VERs, which is expected to increase by a mere 180 MW by 2018. Thus, the ramping needs are not expected to show any noticeable difference.



	2011	2012	2013	2014	2018
Max 1_Hr_Up	1981	1697	1862	2344	1966

Figure B.9: BC Hydro maximum 1-hour net load up ramps



	2011	2012	2013	2014	2018
Max 1_Hr_Dn	-1719	-1520	-1638	-1894	-1711

Figure B.10: BC Hydro maximum 1-hour net load down ramps

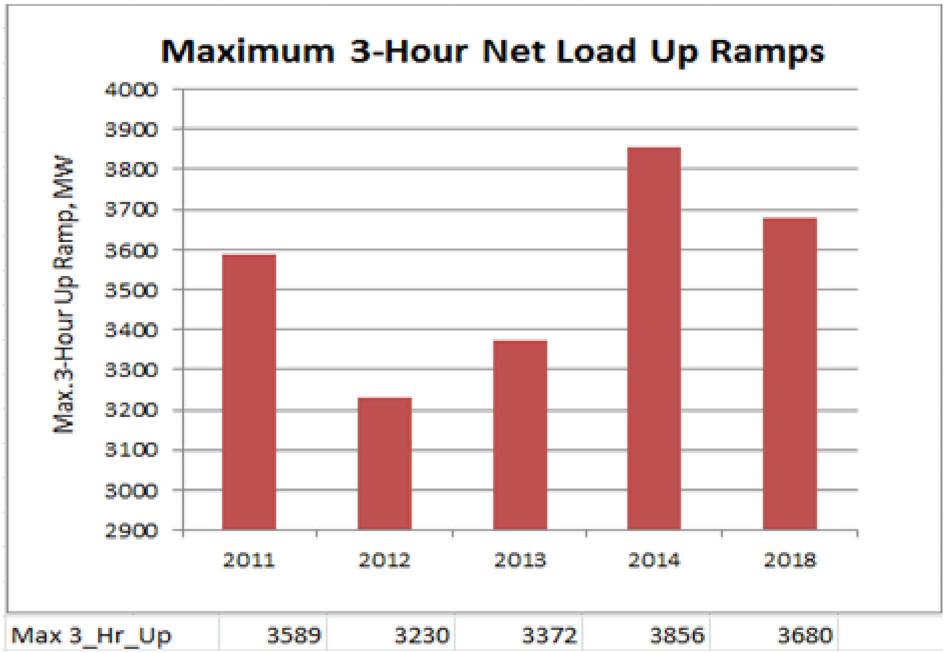


Figure B.11: BC Hydro maximum 3-hour net load up ramps

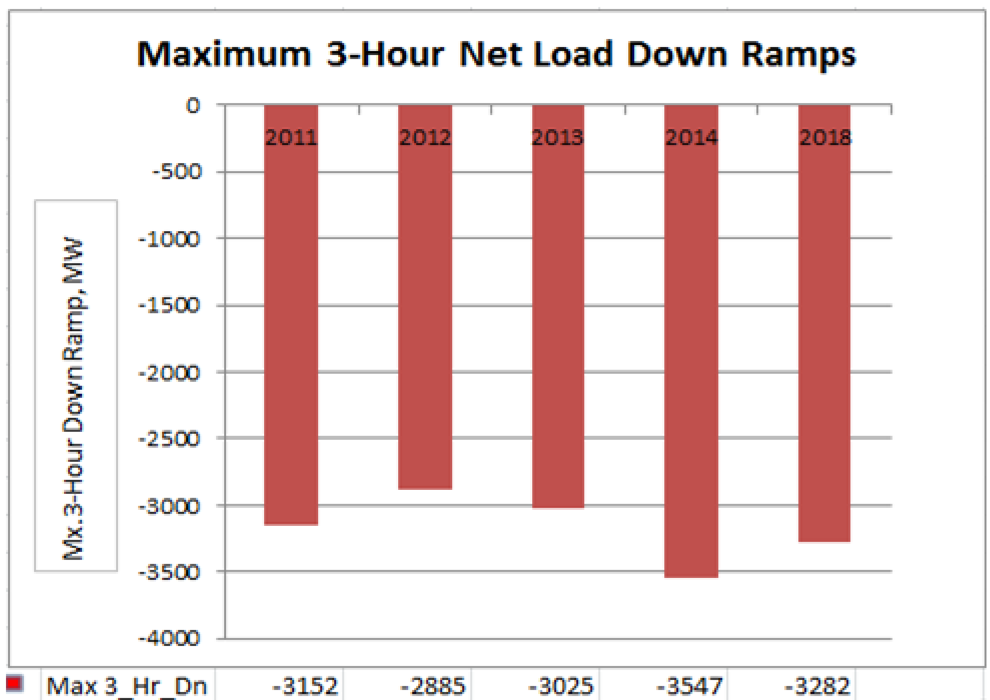


Figure B.12: BC Hydro maximum 3-hour net load up ramps

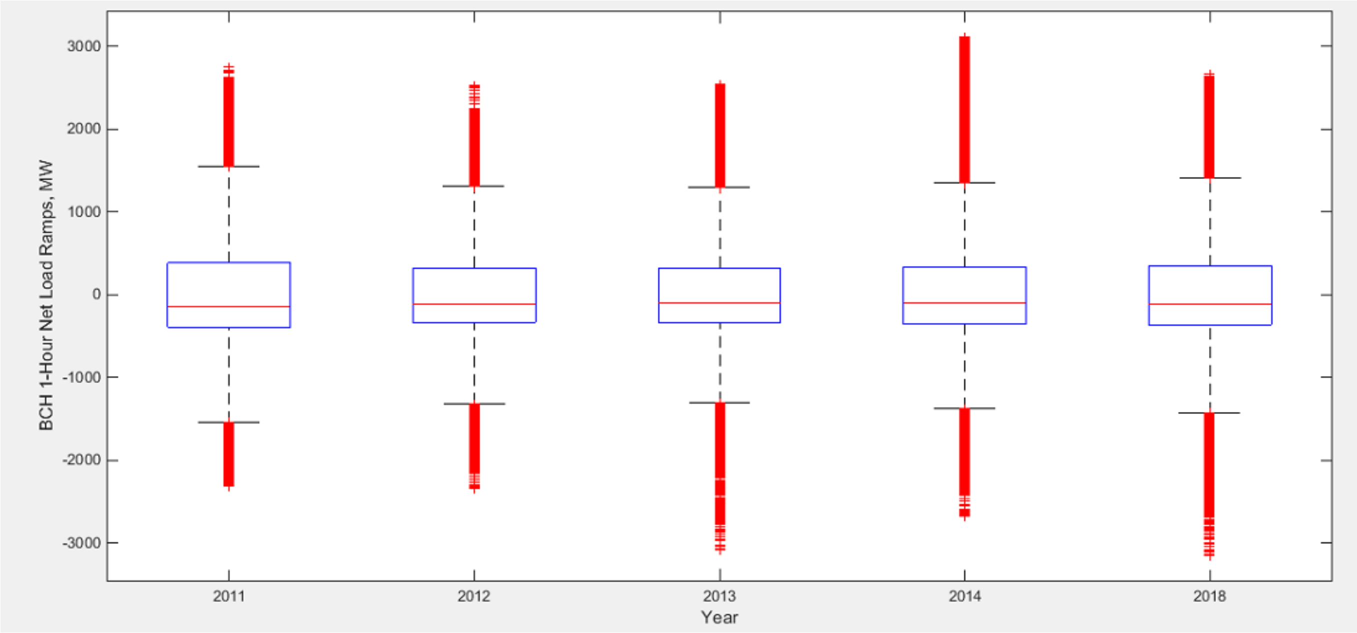


Figure B.13: Boxplot for BCH 1-hour net load ramps 2011–2018

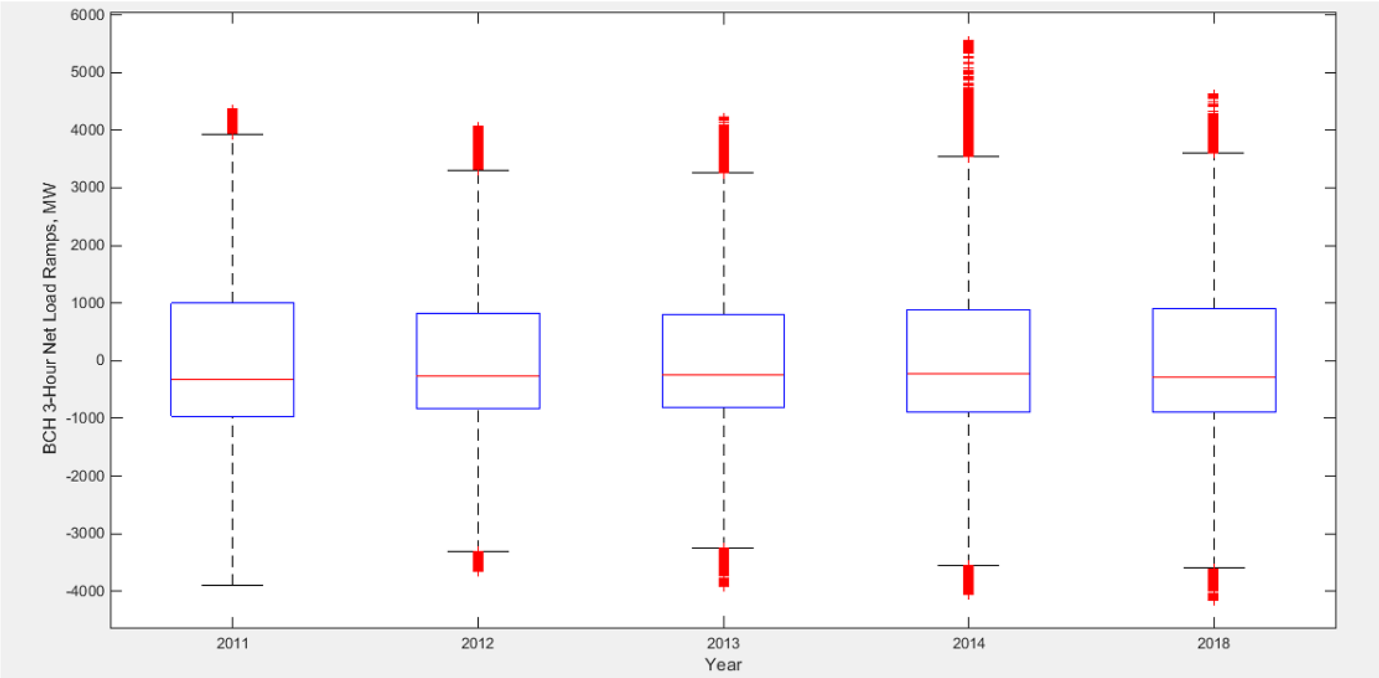


Figure B.14: Boxplot for BCH 3-hour net load ramps 2011–2018

Duke Energy

Duke Energy (Duke) has three separate BAs: Duke Energy Florida (DEF), Duke Energy Carolinas (DEC), and Duke Energy Progress (DEP). For all three Duke Energy areas there is no HVDC export/import capacity, and imports at any hour are zero. All three are part of the Eastern Interconnection and all ties to neighbors are ac.

Duke has previously employed variations of these measures for some time and sees promise in them as reliability metrics. Duke intends to refine the data and analyses and has already identified potential improvements in data collection and analysis, and in the measures themselves.

Duke's BAs have varying generation composition and load characteristics, but none currently has or is forecast to have significant penetrations of nonsynchronous generation (NSG) as compared to CAISO and ERCOT.

As Duke continues to refine data collection and analysis for these measures, it is expected that other anomalies will be identified and resolved.

Duke Energy Florida

DEF BA Ramp Rates 2013

Note: Only data for 2013 was available in time for this report. Since there is no measurable NSG projected, no projection for 2018 was needed or made.

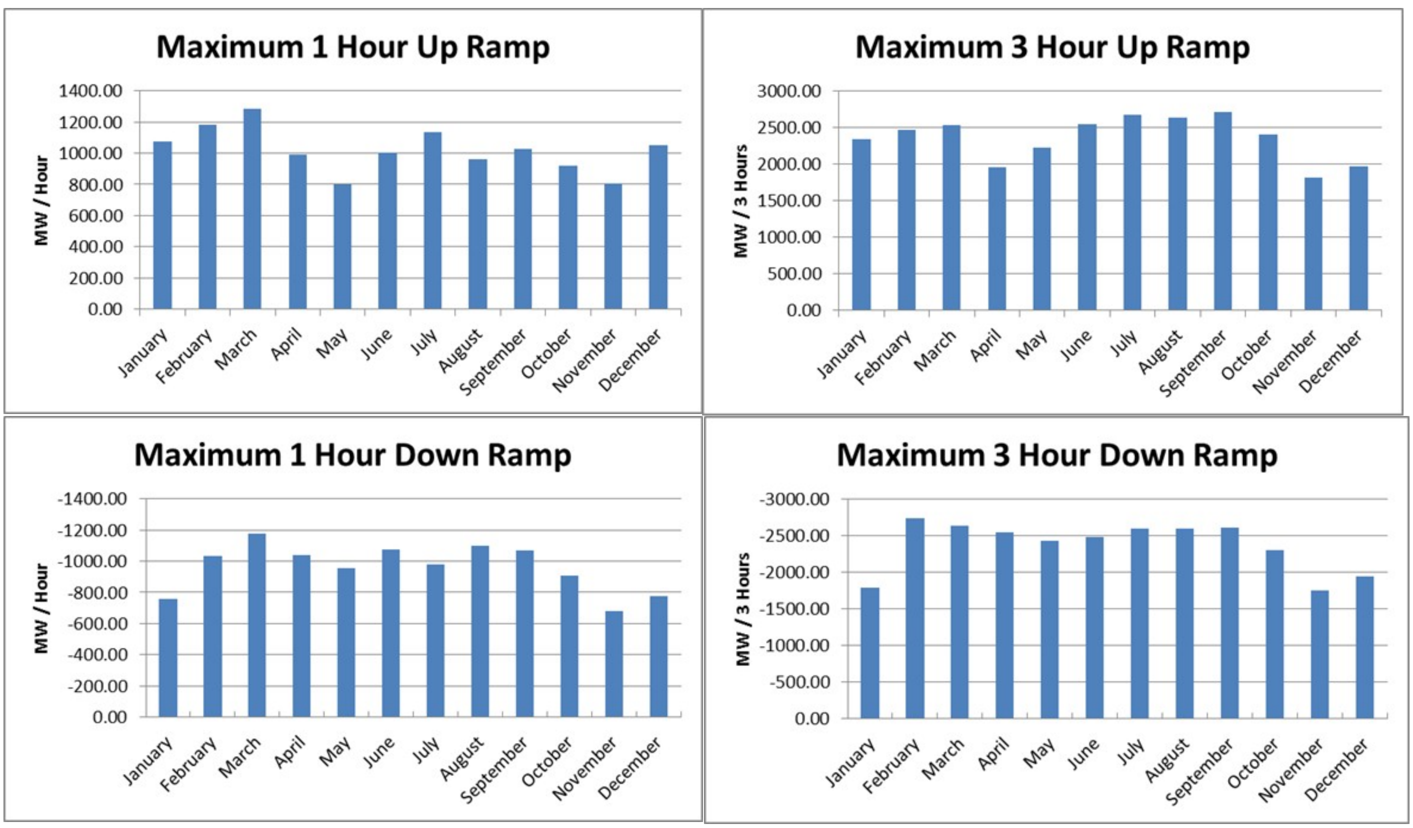


Figure B.15: BC Hydro maximum 1-hour net load up and down ramps

Duke Energy Carolinas (DEC)

Note: Only data for 2014 was available in time for this report. Since there is measurable NSG projected, a projection for 2018 was made.

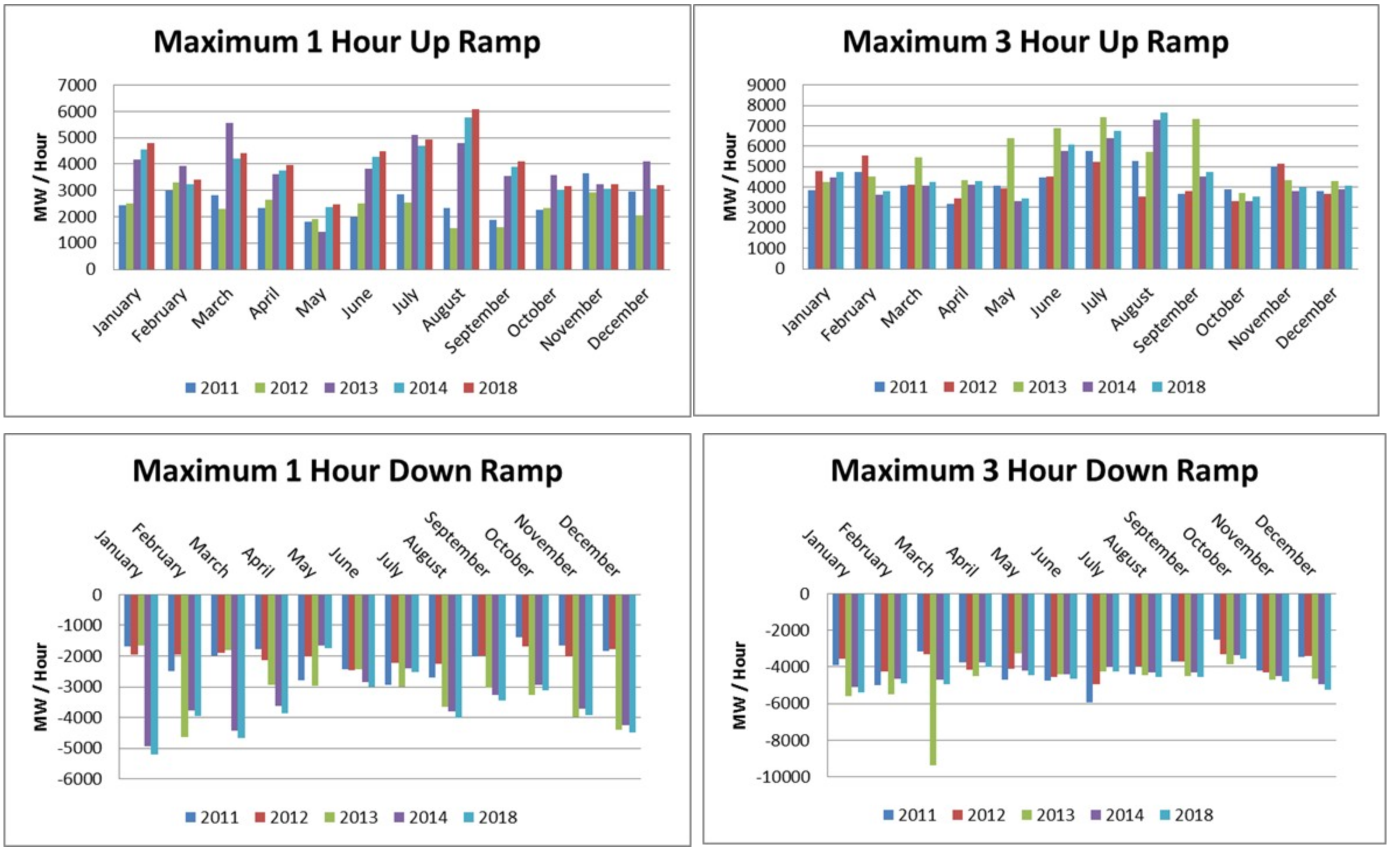


Figure B.16: Duke Energy Carolinas maximum 1- and 3-hour net load up and down ramps

Duke Energy Progress

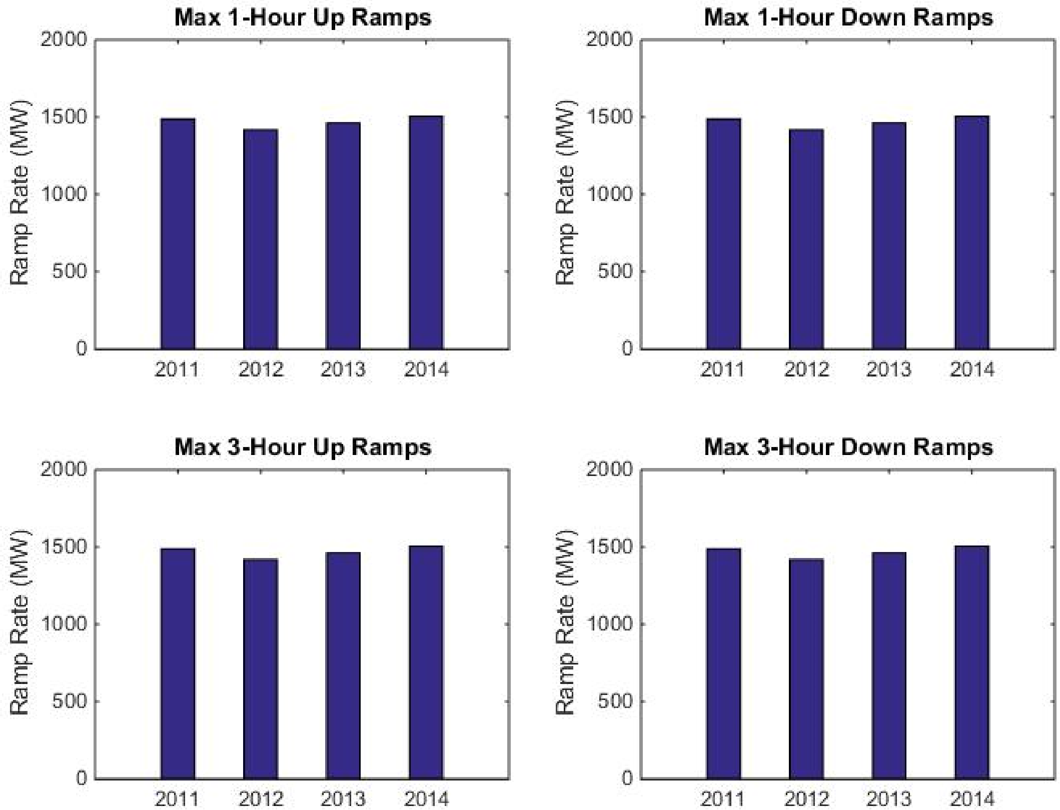


Figure B.17: Duke Energy Progress maximum 1- and 3-hour net load up and down ramps

Southern Company

Through the end of 2014, Southern Company had approximately 454 MW of VERs, which is comprised of 404 MW of wind and 50 MW of solar PV. By 2018, Southern Company expects to see an increase of 250 MW of wind and 1620 MW of solar PV for a total of 2,324 MW of VERs. Even with an increase of 500 percent of VERs between 2014 and 2018, Southern Company does not anticipate any noticeable increase in intrahour or multihour ramps.

Measure 6

Ramping Capability Measures

The historical and projected maximum one-hour-up, one-hour-down, three-hour-up, and three-hour-down net load ramps (actual load less production from VERs) using one minute data.

Year	One hour up	One hour down	Three hour up	Three hour down
2011	6,166	-6,325	11,714	-10,096
2012	5,560	-4,376	10,385	-9,614
2013	4,192	-4,521	9,034	-9,072
2014	4,423	-3,868	9,911	-9,236
2015	4,423	-3,868	9,911	-9,236
2016	4,423	-3,868	9,911	-9,236
2017	4,423	-3,868	9,911	-9,236

NOTE: Values remain unchanged for 2014–2017 because they occur outside of the solar energy operating hours (For example: 3-hour down occurs in hour 23).

Year	Wind Capacity, MW	PV, MW
2011	0	0
2012	0	0
2013	202	46
2014	404	50
2015	404	1,182
2016	654	1,182
2017	654	1,670

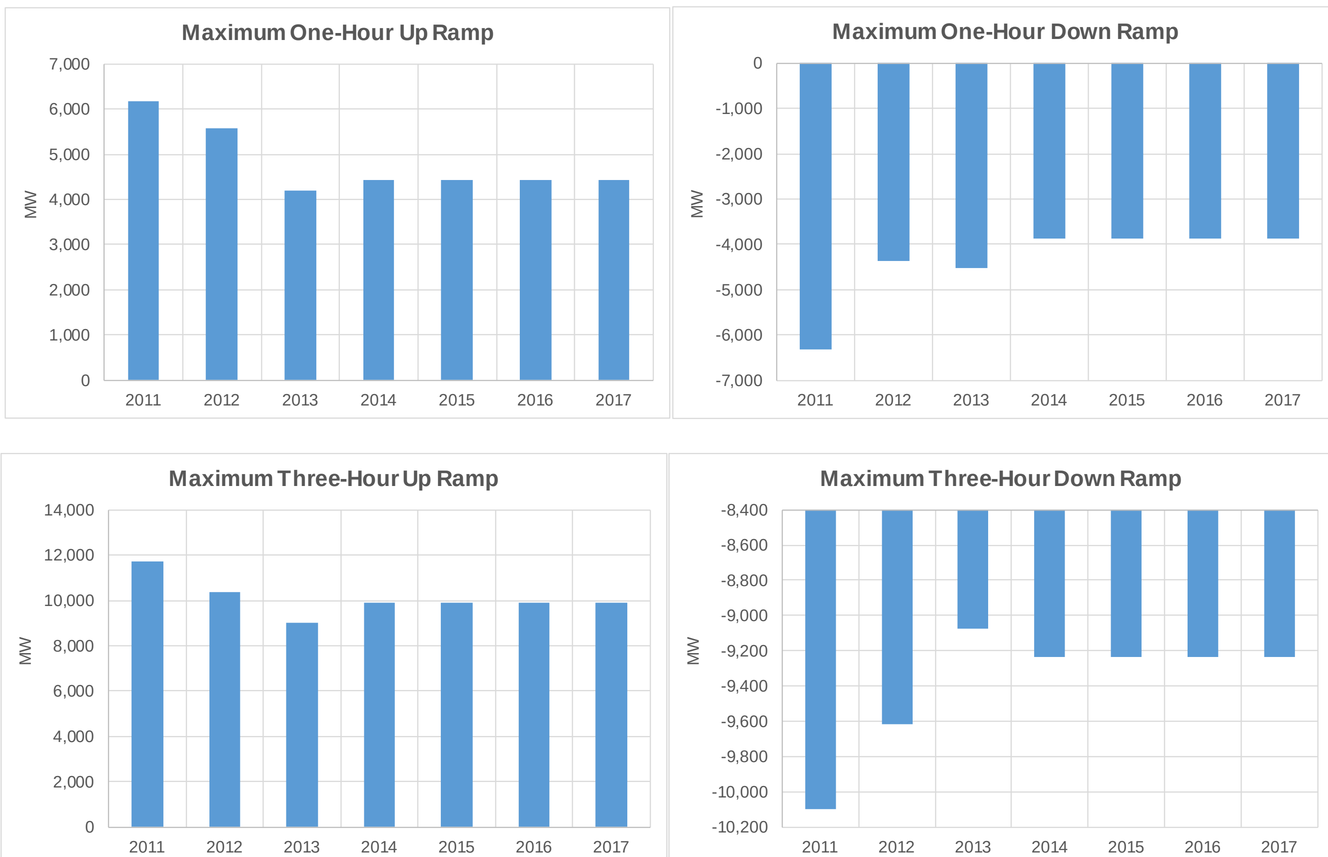
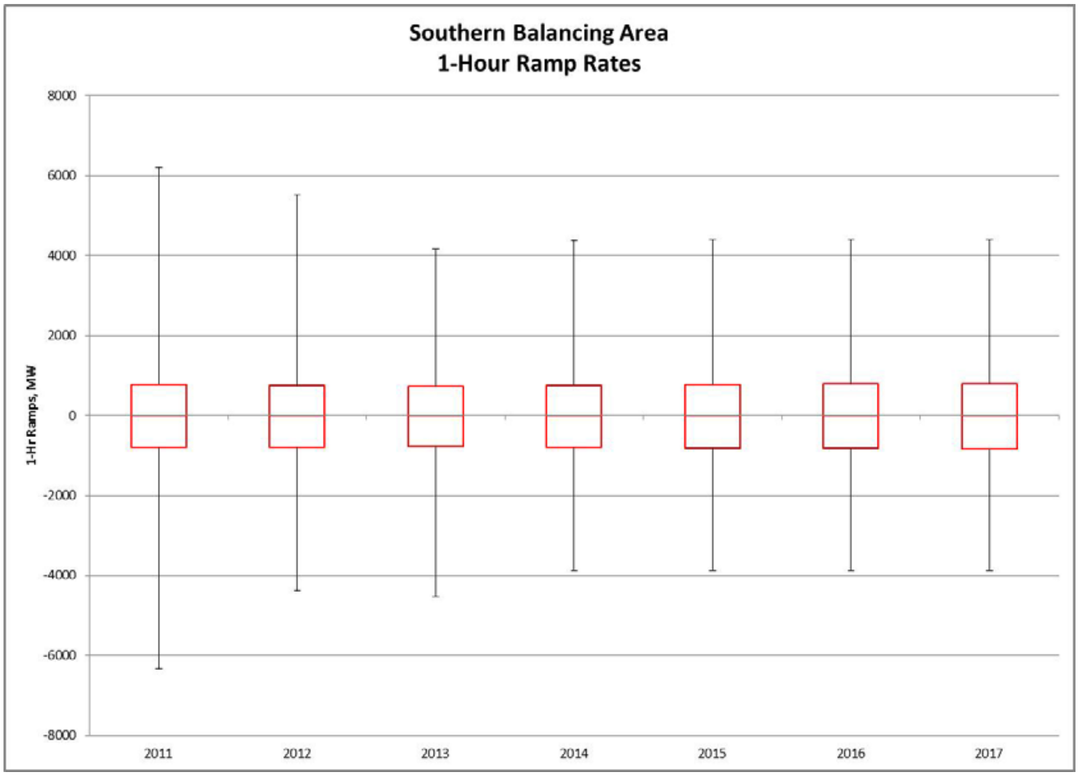


Figure B.18: Southern Company maximum 1- and 3-hour net load up and down ramps



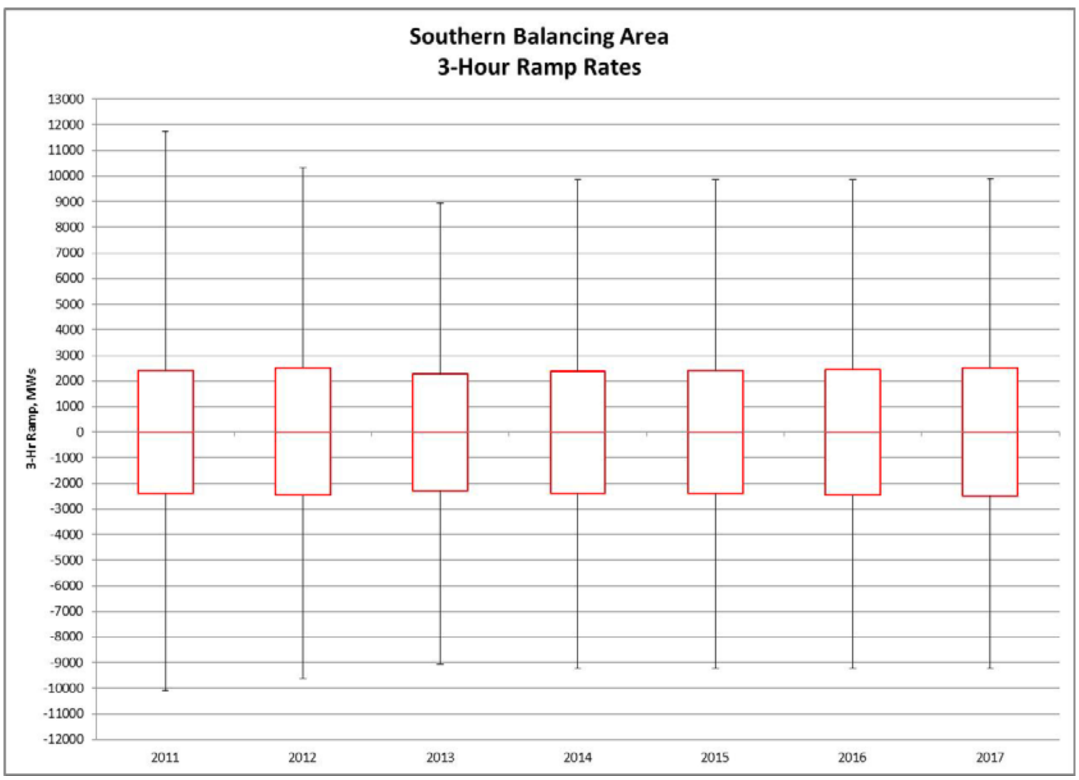


Figure B.19: Southern Company's Maximum 1- and 3-hour net load up and down ramp rates

PJM

By the end of 2014, PJM had approximately 7,029 MW of installed capacity of VERs (approximately 8,810 MW if behind-the-meter is included). This is expected to increase to 15,800 MW by 2018. As shown in Figure B.20, PJM does not expect to see any noticeable increase of ramping needs either in the 1-hour or 3-hour time frame.

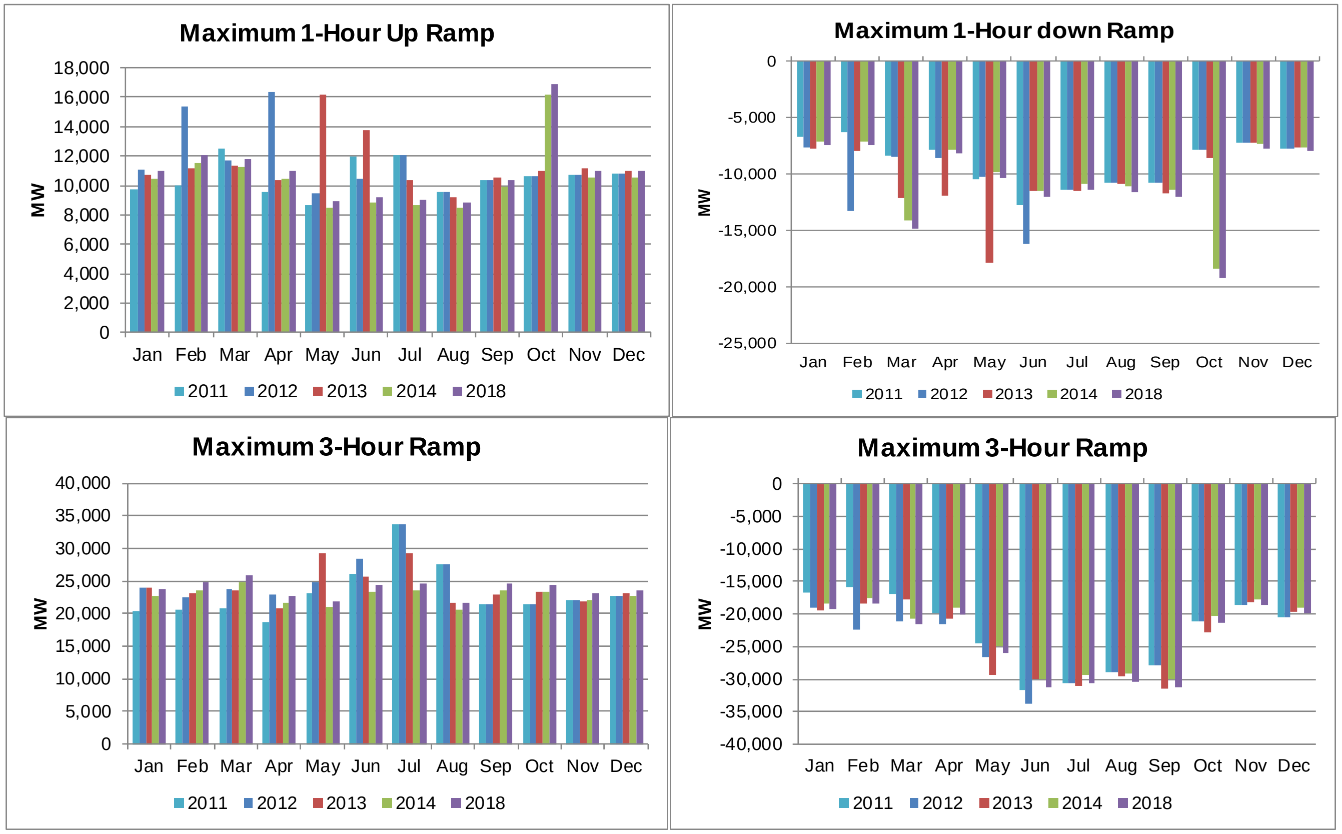


Figure B.20: PJM Maximum 1- and 3-hour net load up and down ramps

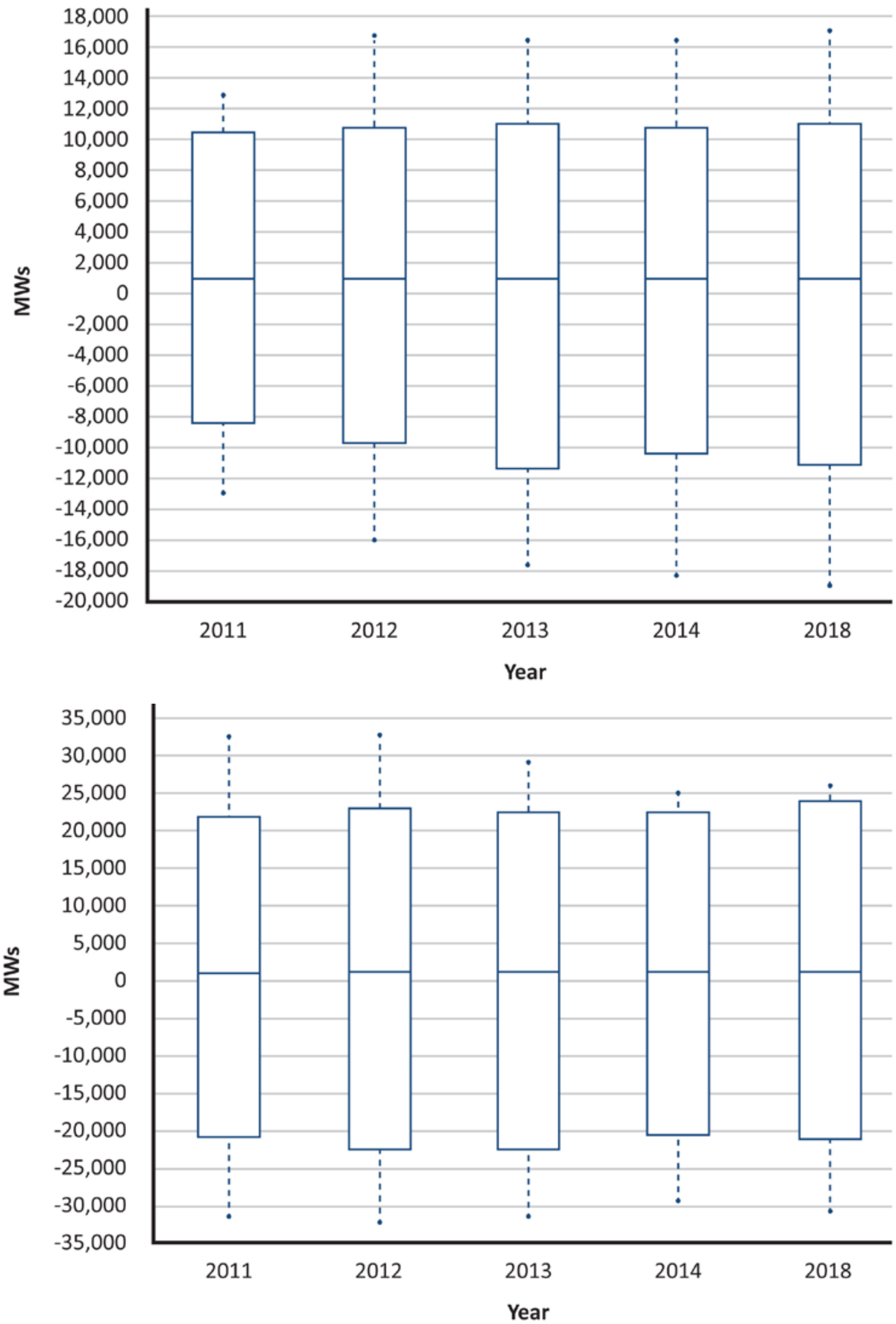


Figure B.21: PJM Maximum 1-hour and 3-hour net load up and down ramps

IESO

By the end of 2014, IESO had approximately 2,845 MW of installed capacity of VERs (wind only). This is expected to increase to 4,377 MW by 2018 (wind and solar). As shown in Figure B.22 IESO is not experiencing any noticeable increase of ramping needs either in the 1-hour or 3-hour time frame. It is important to note that IESO implemented wind dispatch in 2013. As a result, the data will understate the issue of wind ramps adding to the normal ramp requirement. IESO now uses wind to manage much of its ramp requirements due to interchange/demand change. Note that this data is in 10-minute increments with an hourly ramp requirement, which differs from the rolling hour calculation, as done by CAISO.

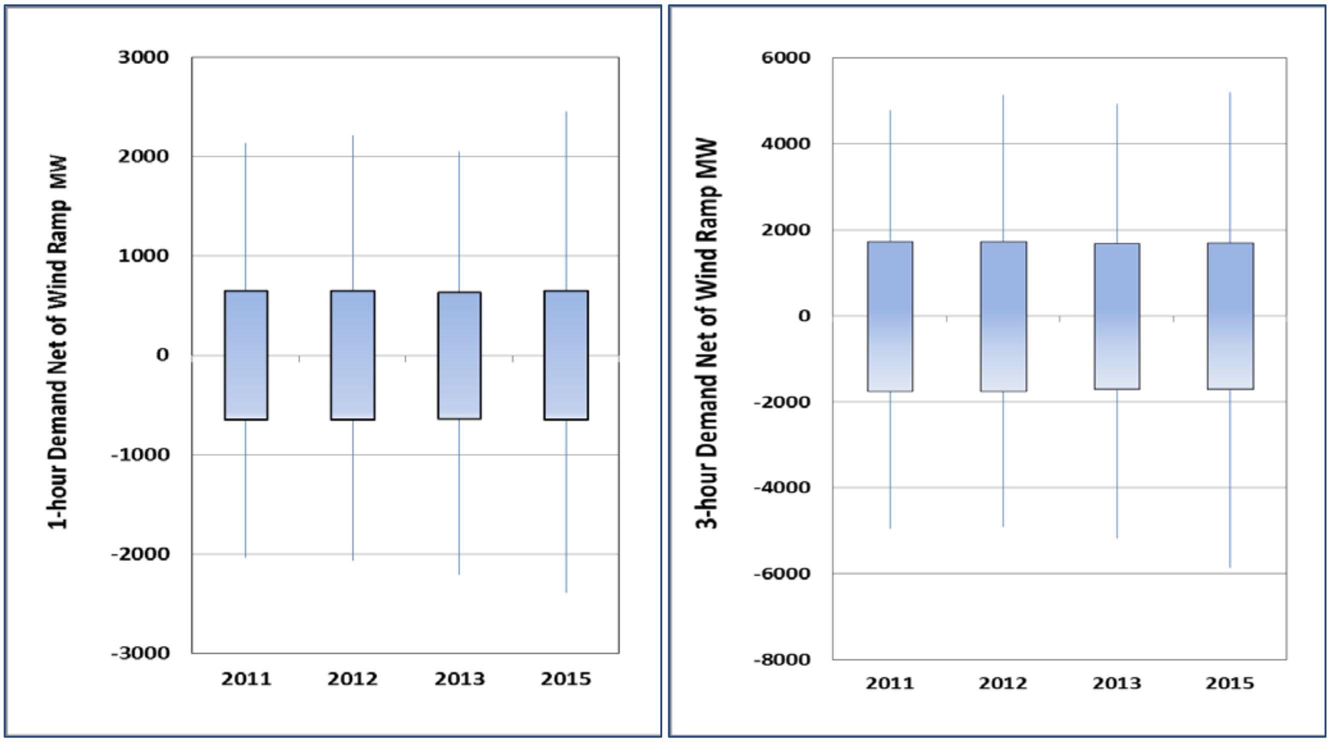


Figure B.22: IESO Maximum 1-hour and 3-hour net load up and down ramps

Appendix C – Control Performance Standards (CAISO Example)

Each BA within an interconnection has an obligation to support the interconnection frequency in real time. A BA's ability to support the interconnection frequency in real time is measured by how well it complies with NERC's Control Performance Standard 1 (CPS1) and Balancing Authority ACE Limit (BAAL) performance measures.

Control Performance Standard 1 (CPS1)

CPS1 is a statistical measure of a BA's area control error (ACE) variability in combination with the interconnection frequency error from scheduled frequency. It measures the covariance between the ACE of a BA and the frequency deviation of the interconnection, which is equal to the sum of the ACEs of all of the BAs. CPS1 assigns each BA a share of the responsibility for controlling the interconnection's steady-state frequency. The CPS1 score is reported to NERC on a monthly basis and averaged over a 12-month moving window. A violation of CPS1 occurs whenever a BA's CPS1 score for the 12-month moving window falls below 100 percent.

As an example, CAISO's CPS1 score for January 3, 2015, was 134.2 percent, which is well above the minimum 100. However, by monitoring the CPS1 score on an hourly basis, CAISO was able to determine the hours when its CPS1 scores dropped below 100 percent and determine the root cause. A closer look revealed that these hours coincided with its steep evening upward net load[19] ramp, shown in Figure C.1. The red curve is the net demand and the blue bars are the average CPS1 scores for each hour. The blue horizontal line represents a CPS1 score of 100 percent. Whenever the blue bars are above the blue line, the BA is supporting the interconnection frequency; when the blue bars fall below the blue line, the BA is leaning on the interconnection.

By analyzing CPS1 performance and performing technical studies, CAISO determined the need for flexible resources to be committed with sufficient ramping capability over a three-hour period to meet the expected increase in load and the simultaneous drop-off in solar production. System operators must rely on ramping capability in both speed and quantity to balance the VERs' production change. Also, any under-forecasting or over-forecasting of demand requires dispatching flexible resources at higher or lower levels, respectively, in order to minimize inadvertent energy flows with neighboring BAs.

[19] Net Load = Load – Wind - Solar

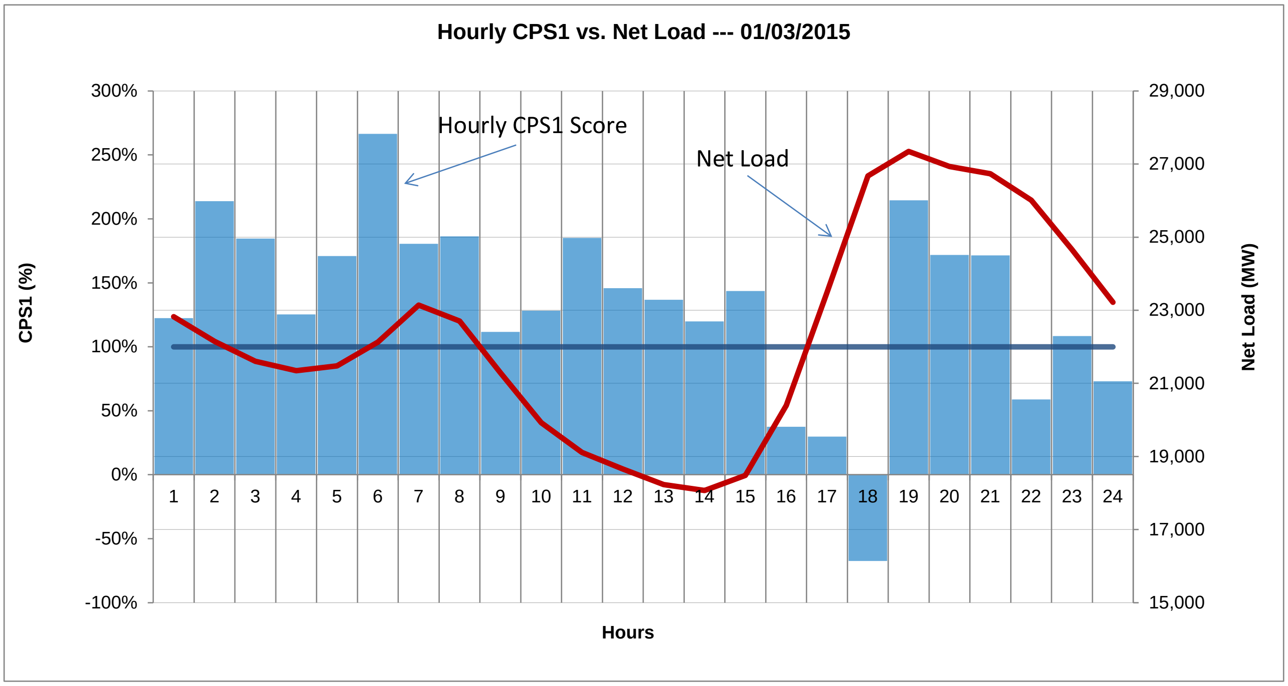


Figure C.1: Net demand vs hourly CPS1 scores 01/03/2015

To help manage the lack of fleet flexibility, CAISO is currently implementing a ramping tool[20] to predict and alert system operators of the load-following capacity and ramping requirements needed on the system in real time. CAISO is also introducing a flexible ramp product[21] to ensure enough dispatchable capacity will be available on a five-minute dispatch basis in the real-time market.

Balancing Authority ACE Limit (BAAL)

BAAL provides each BA with two dynamic ACE limits, each of which is a function of the interconnection frequency. These two dynamic ACE limits—(1) $BAAL_{High}$ and (2) $BAAL_{Low}$—are unique for each BA and are based on a BA's frequency bias and the interconnection's 1-minute frequency error (epsilon 1). As interconnection frequency deviates from scheduled frequency, the ACE limit for each BA becomes more restrictive. BAAL replaced CPS2, which was not designed to address interconnection frequency. A BAAL excursion occurs when the BAAL limit is exceeded for more than 30 consecutive minutes.

Also, by observing the hours when BAAL limits are exceeded, the BA can commit resources accordingly. For example, within CAISO's footprint, during middays with high solar production, there is less need to commit additional resources, but toward sunset an immediate need exists to replace the solar generation to continue meeting consumer demand. Many resources that could replace solar generation must be committed prior to this significant ramp, which begins before sunset. These resources often require several hours to a day or more to fully come on-line, which can result in more generation on-line than consumer demand, causing overgeneration conditions. By 2020, CAISO expects that increased flexibility will be needed to reliably meet two net load peaks, which would require managing approximately 7,000 MW of upward and downward ramps in three-hour time frames, and provide nearly 13,000 MW of continuous up-ramping capability to meet the evening peak, also in a three-hour time frame.

[20] http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-21112.pdf
[21] http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

Knowing these challenges ahead of time relieves the system operator of real-time surprises and uncertainty.

Figures C.2 and C.3 show the BAAL for each minute of the operating day. As shown, for 14 minutes, the upper BAAL limit was exceeded during hour 18. A closer look at the root cause revealed the system area control error was high because more generation had to be committed to meet the evening three-hour upward ramp.

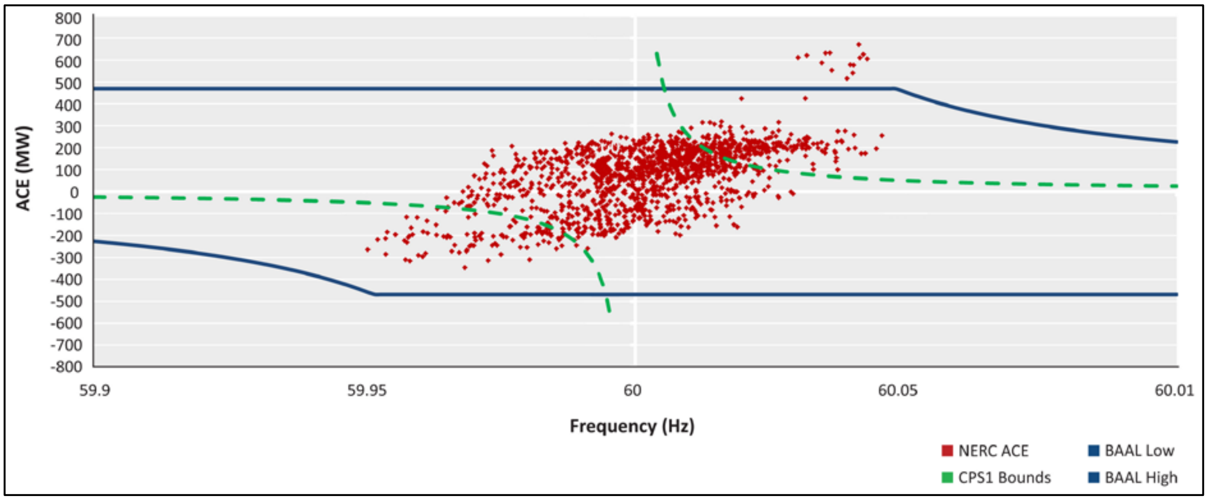


Figure C.2: Frequency of BAAL 1-minute exceedances

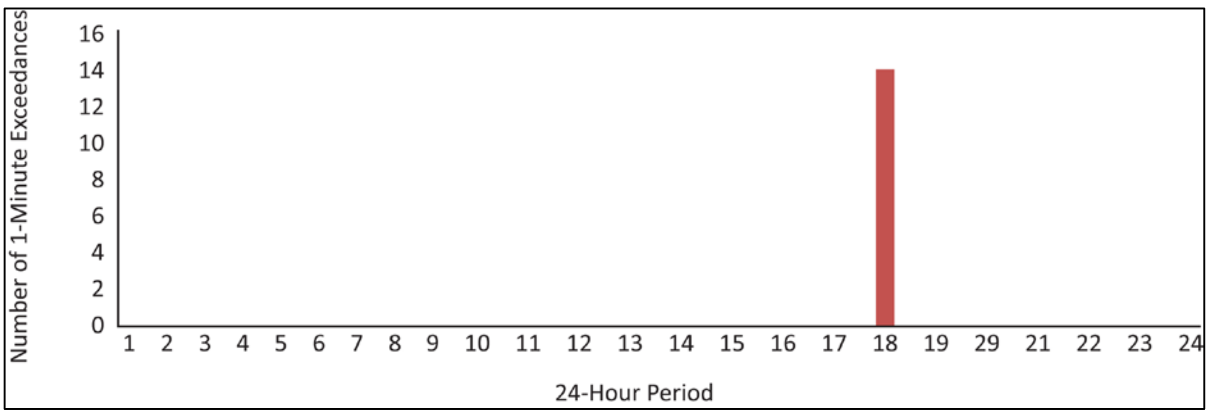


Figure C.3: Frequency of BAAL hourly exceedances

Appendix D – Reactive Power and Voltage Control

Background

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

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

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

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

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

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

Reliability Considerations

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

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

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

Trends in the Industry

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

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

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

Proposed Measures

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

Data for Measure 7: Reactive Capability on the System

The ERSTF requested and obtained extensive data from system operators for Measure 7. The method is described immediately below and the results from participating system operators follow.

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

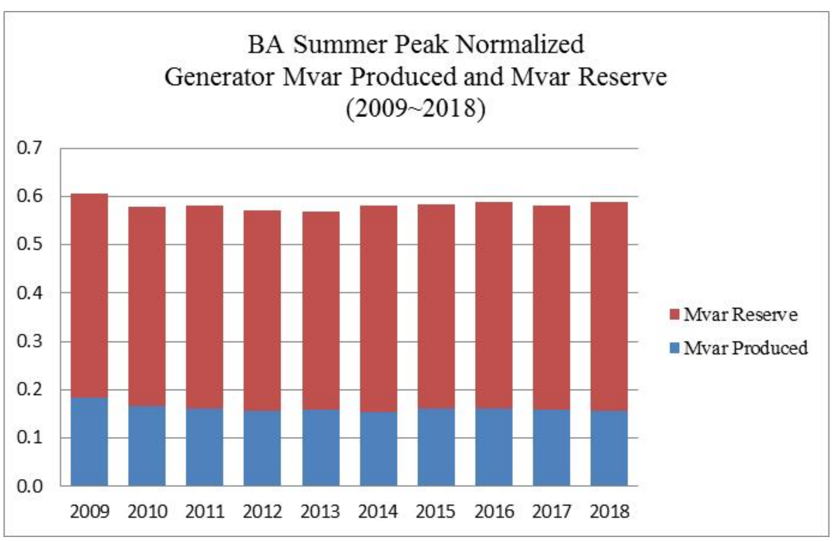


Figure D.1: Generator Mvar – produced and reserve at BA level

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

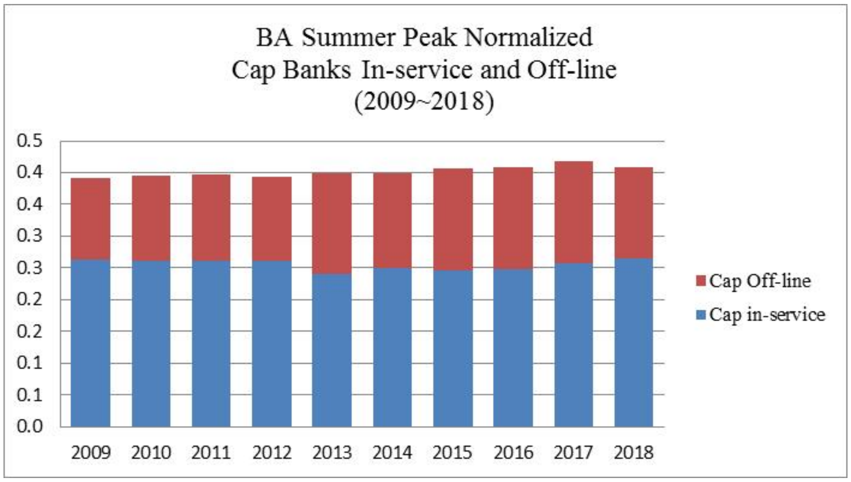


Figure D.2: Capacitor Mvar – off-line and on-line at BA level

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

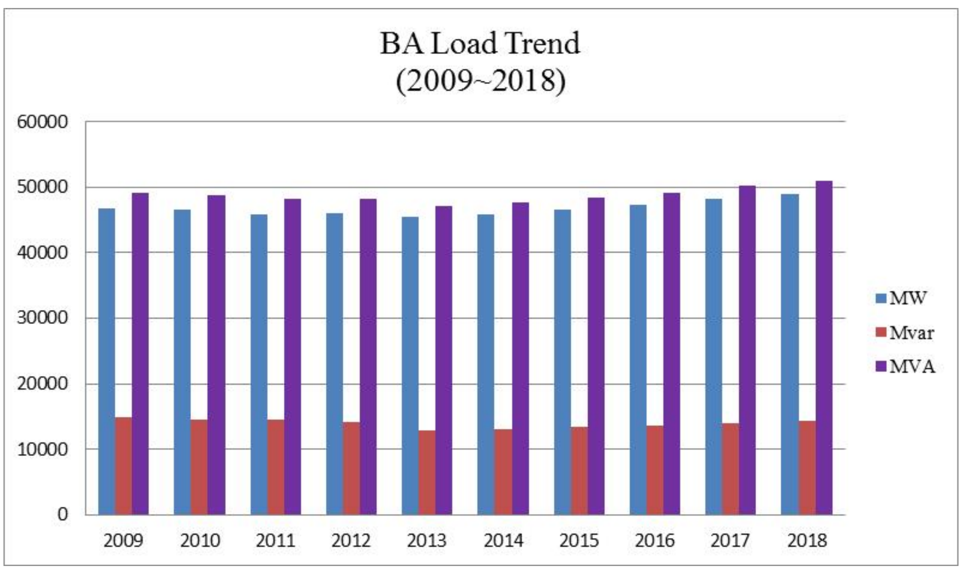


Figure D.3: Load trend at BA level

Results of Analysis by BA

Duke Energy Carolinas – Planning – Dynamic (p.u.)

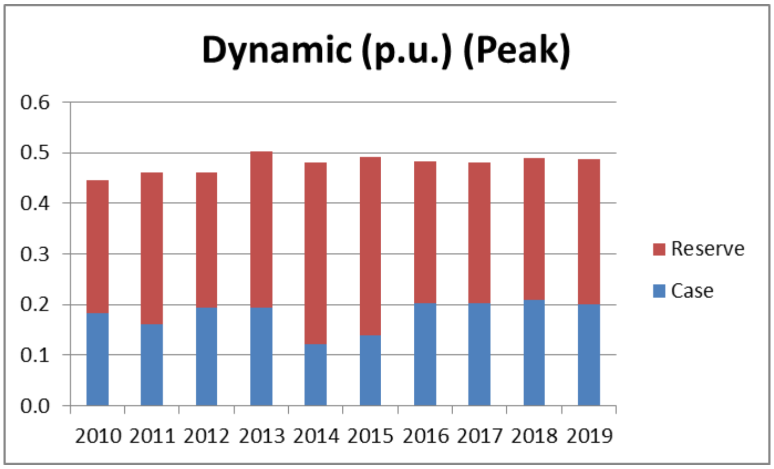


Figure D.4: Duke Energy Carolinas – Planning – Dynamic (p.u.) Peak

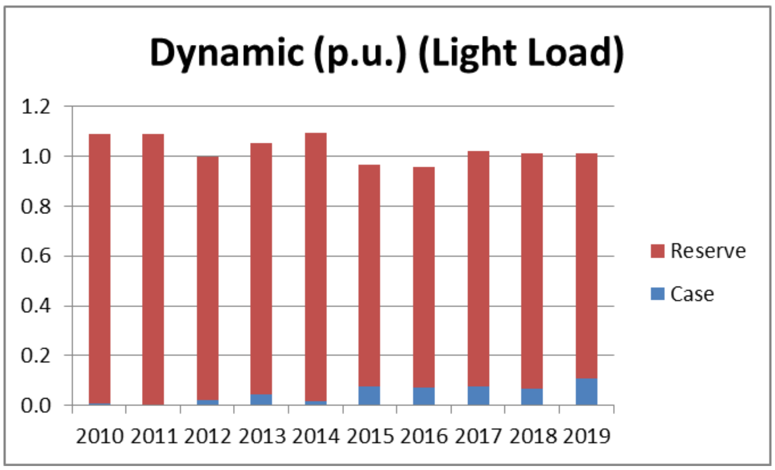


Figure D.5: Duke Energy Carolinas – Planning – Dynamic (p.u.) Light Load

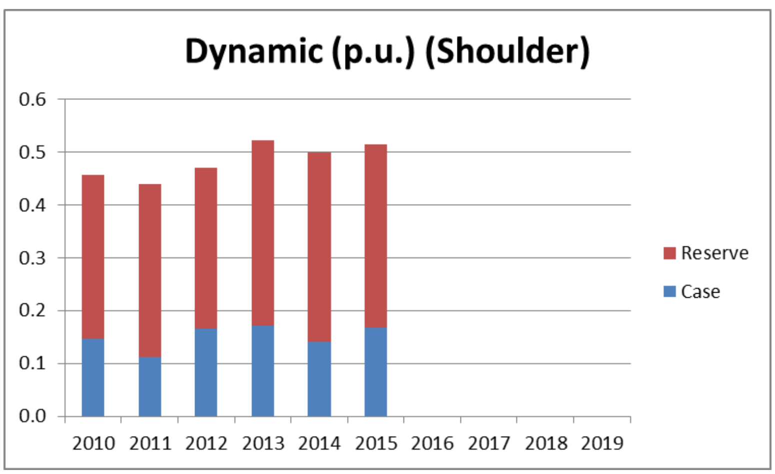


Figure D.6: Duke Energy Carolinas – Planning – Dynamic (p.u.) Shoulder

Duke Energy Carolinas – Planning – Static System (p.u.)

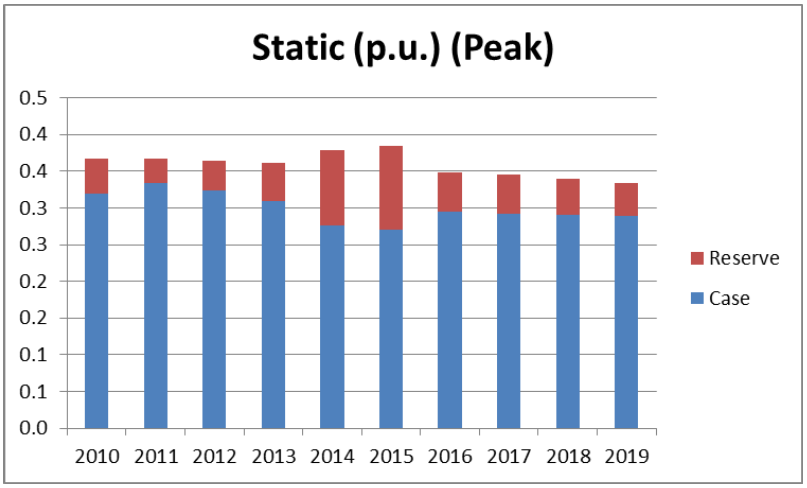


Figure D.7: Duke Energy Carolinas – Planning – Static (p.u.) Peak

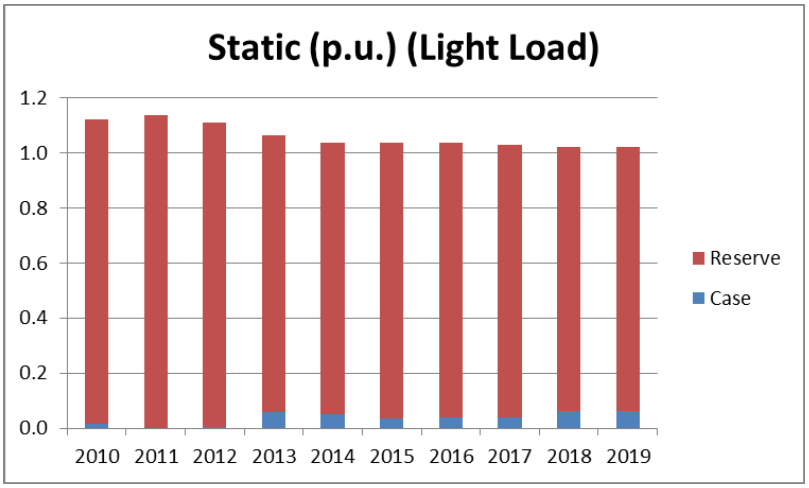


Figure D.8: Duke Energy Carolinas – Planning – Static (p.u.) Light Load

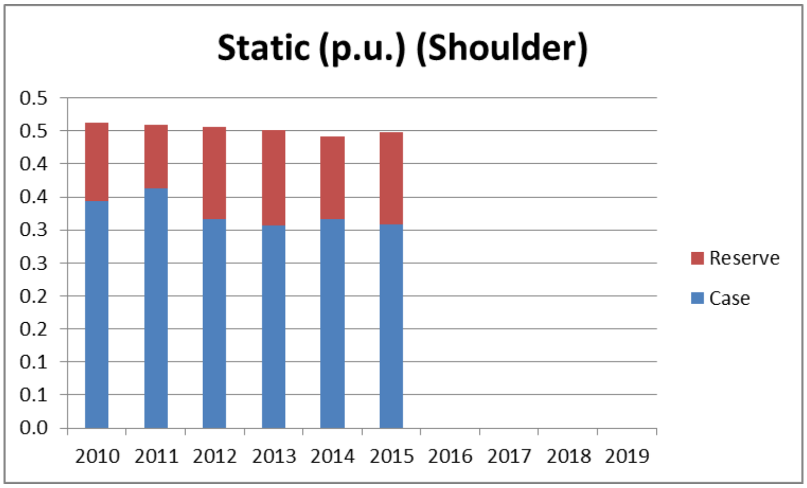


Figure D.9: Duke Energy Carolinas – Planning – Static (p.u.) Shoulder

Duke Energy Carolinas – Planning – Load Trend (MW)

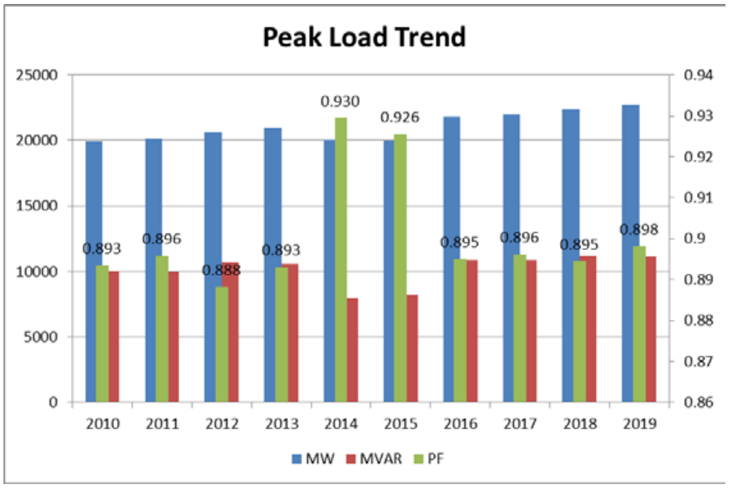


Figure D.10: Duke Energy Carolinas – Planning – Peak Load Trend (MW)

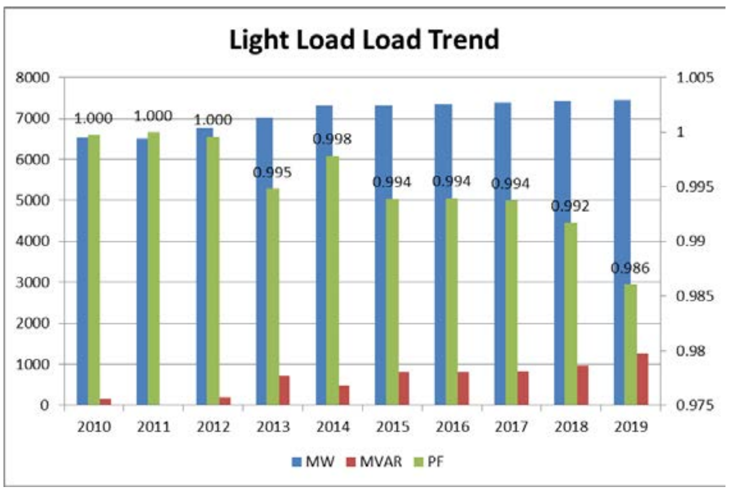


Figure D.11: Duke Energy Carolinas – Planning – Light Load Trend (MW)

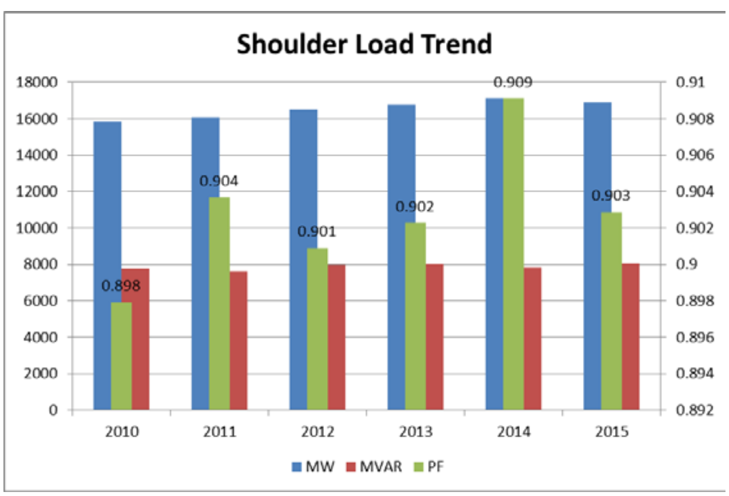


Figure D.12: Duke Energy Carolinas – Planning – Shoulder Load Trend (MW)

Duke Energy Carolinas – Real Time – Dynamic System (MVAR)

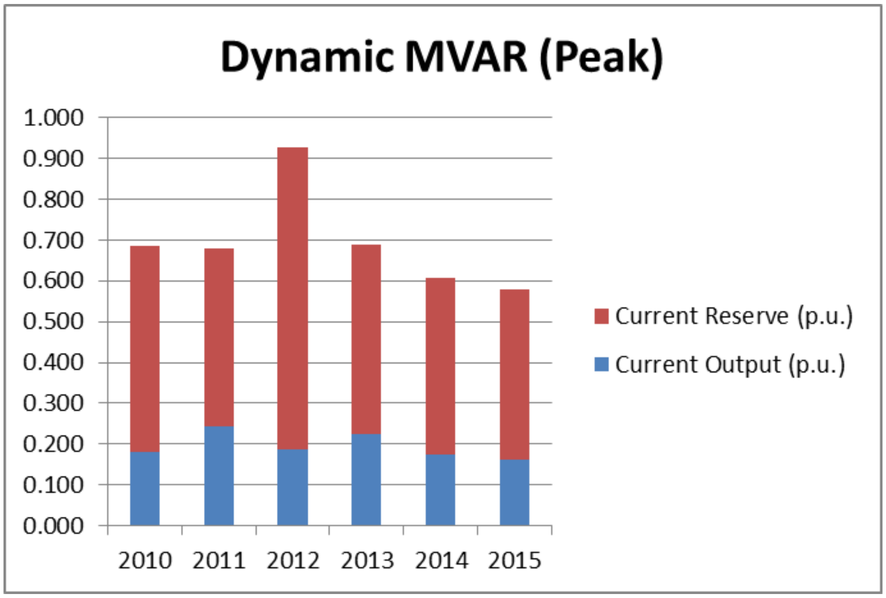


Figure D.13: Duke Energy Carolinas – Real Time – Dynamic MVAR (Peak)

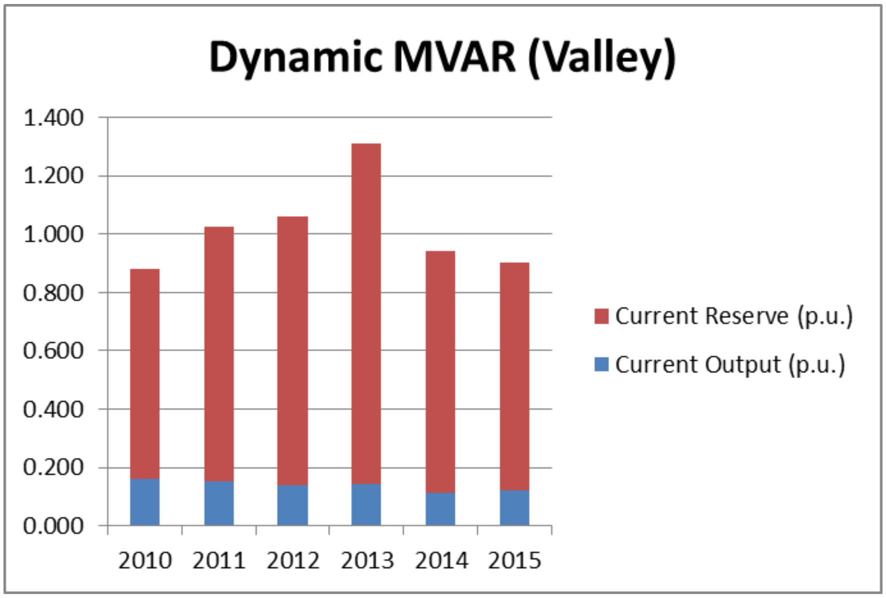


Figure D.14: Duke Energy Carolinas – Real Time – Dynamic MVAR (Valley)

Duke Energy Carolinas – Real Time – Static System (MVAR)

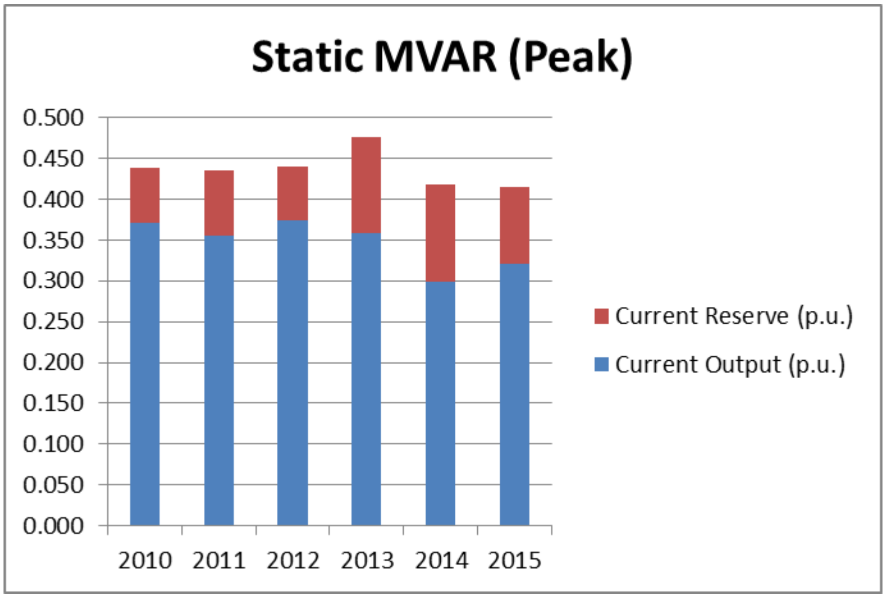


Figure D.15: Duke Energy Carolinas – Real Time – Static MVAR (Peak)

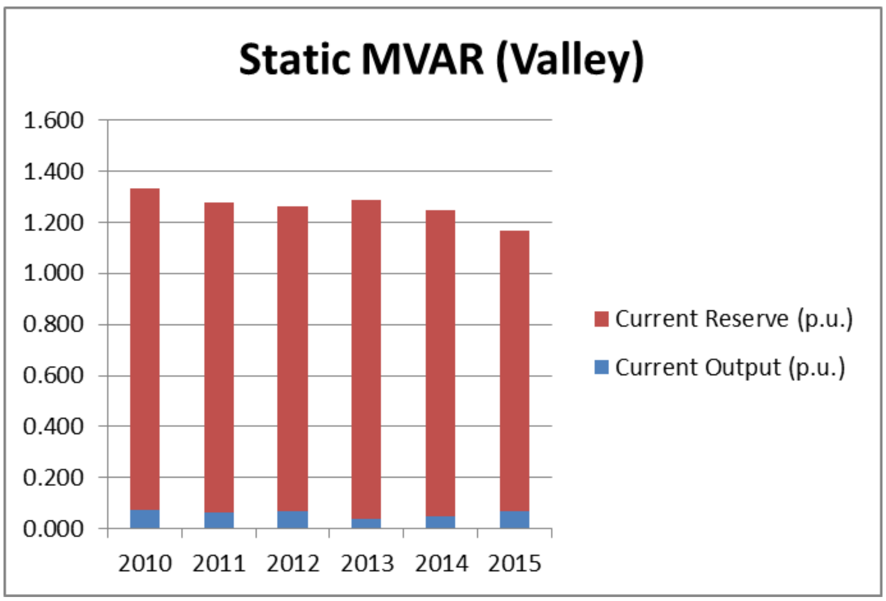


Figure D.16: Duke Energy Carolinas – Real Time – Static MVAR (Valley)

Duke Energy Carolinas – Real Time – Load Trend (MW)

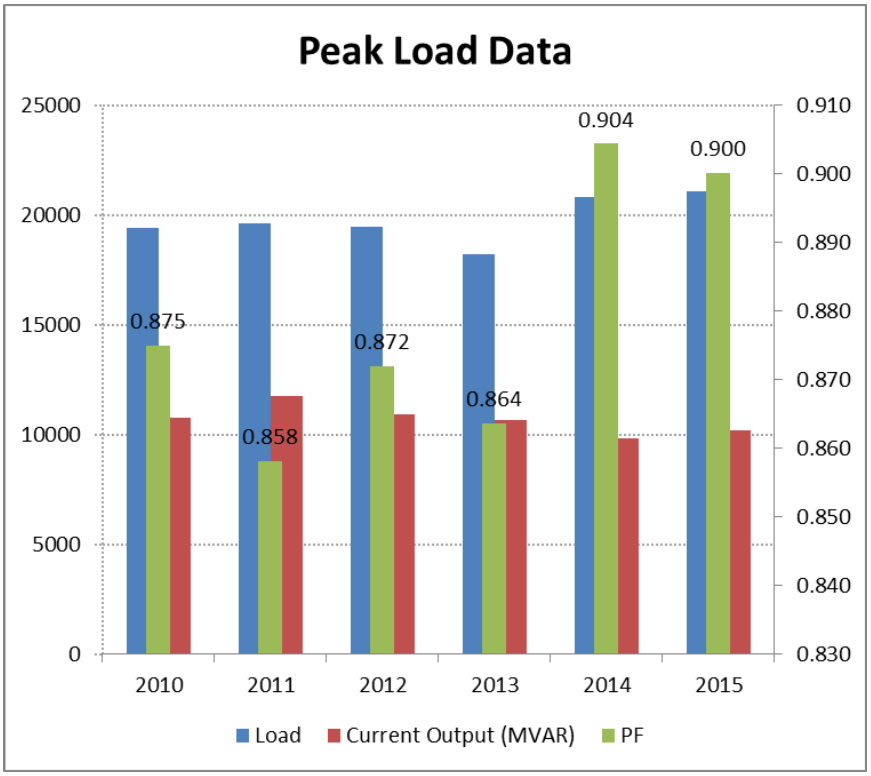


Figure D.17: Duke Energy Carolinas – Real Time – Load Trend (MW)

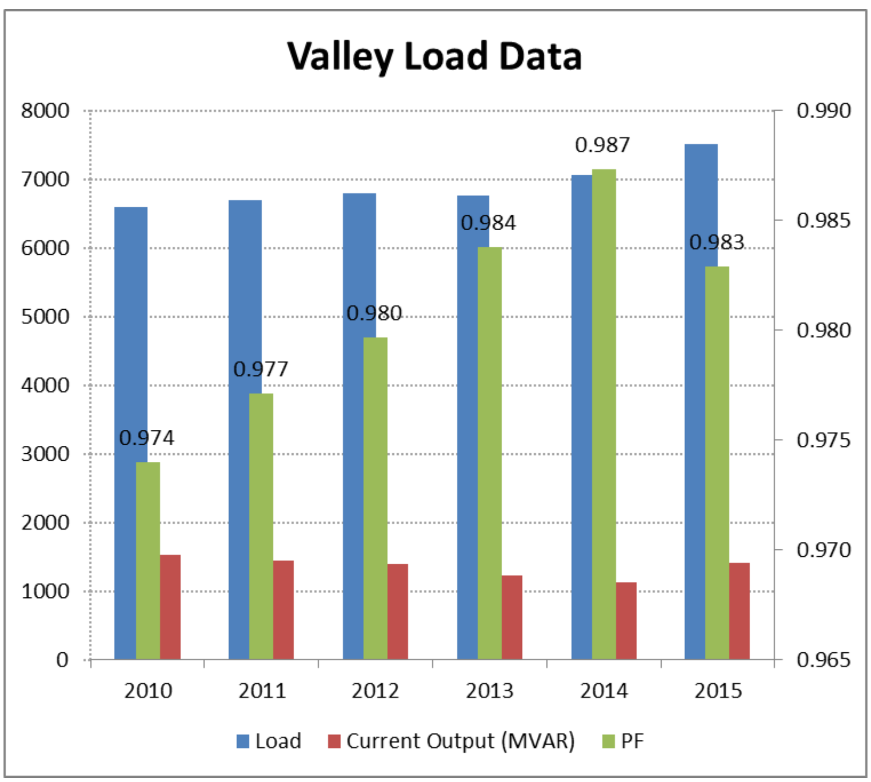


Figure D.18: Duke Energy Carolinas – Real Time – Valley Load Data (MW)

Duke Energy Progress – Planning – Dynamic System (P.U.)

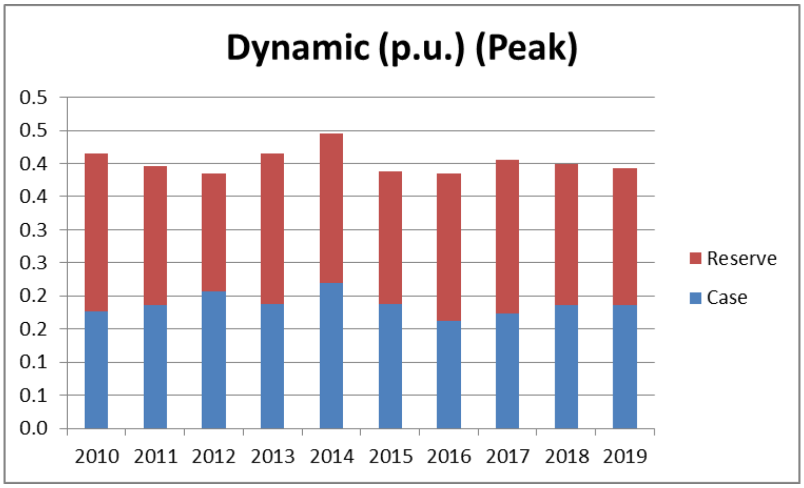


Figure D.19: Duke Energy Progress – Planning – Dynamic System (p.u.) (Peak)

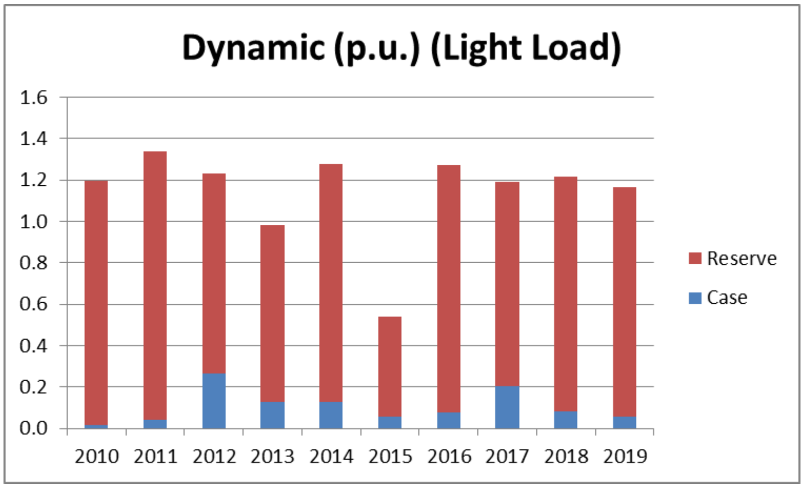


Figure D.20: Duke Energy Progress – Planning – Dynamic System (p.u.) (Light Load)

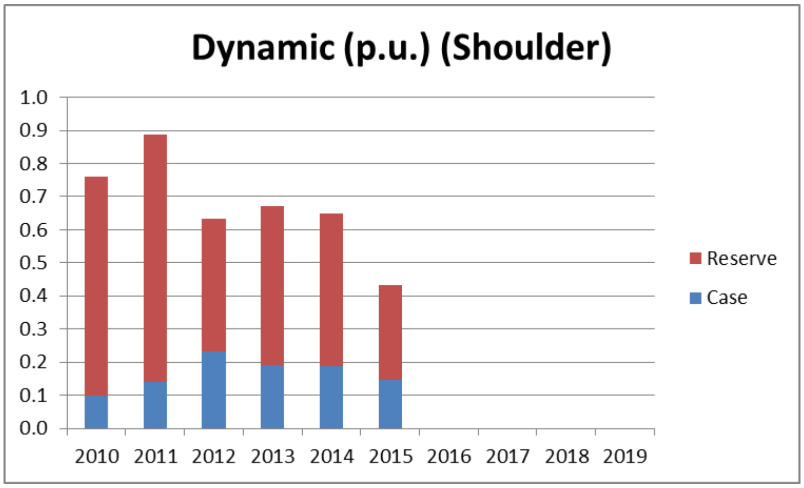


Figure D.21: Duke Energy Progress – Planning – Dynamic System (p.u.) (Shoulder)

Duke Energy Progress – Planning – Static System (P.U.)

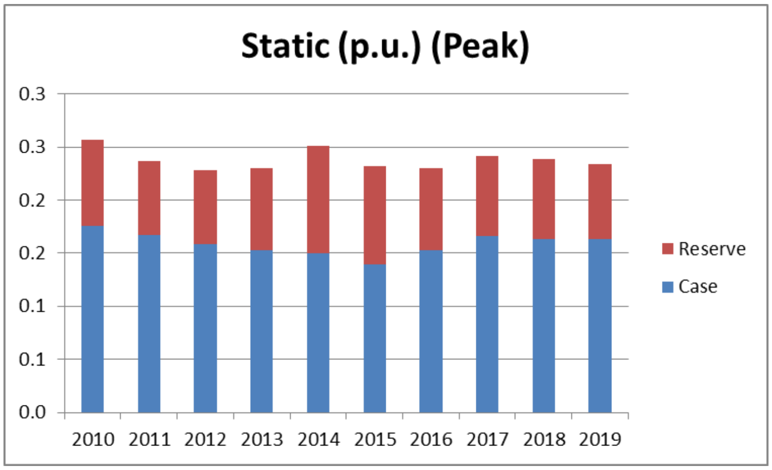


Figure D.22: Duke Energy Progress – Planning – Static System (p.u.) (Peak)

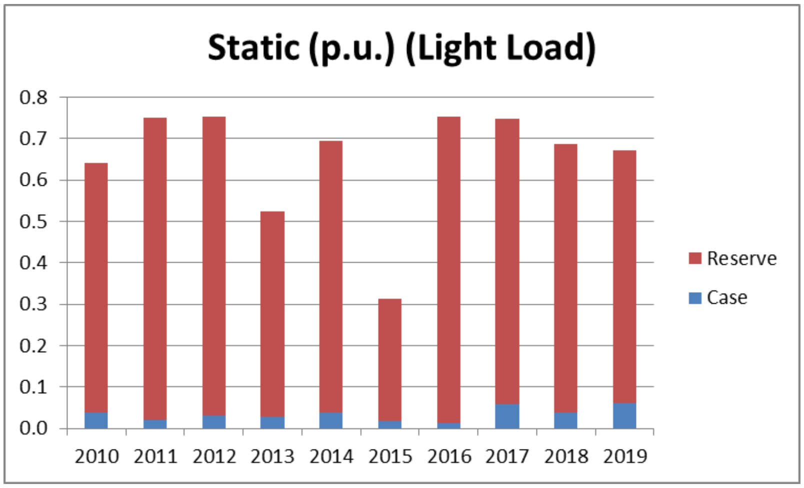


Figure D.23: Duke Energy Progress – Planning – Static System (p.u.) (Light Load)

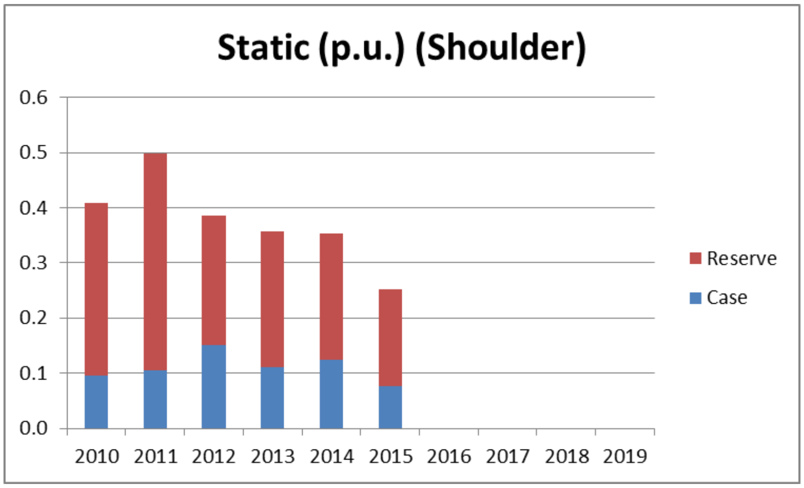


Figure D.24: Duke Energy Progress – Planning – Static (p.u.) (Shoulder)

Duke Energy Progress – Planning – Load Trend (MW)

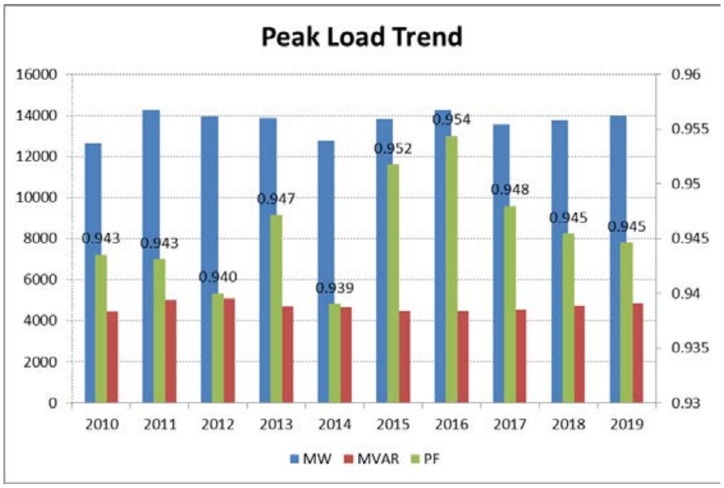


Figure D.25: Duke Energy Progress – Planning – Load Trend (MW) (Peak)

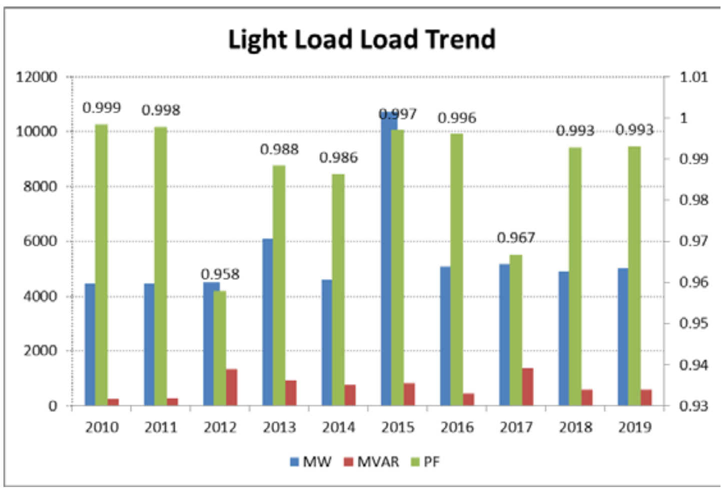


Figure D.26: Duke Energy Progress – Planning – Load Trend (MW) (Light Load)

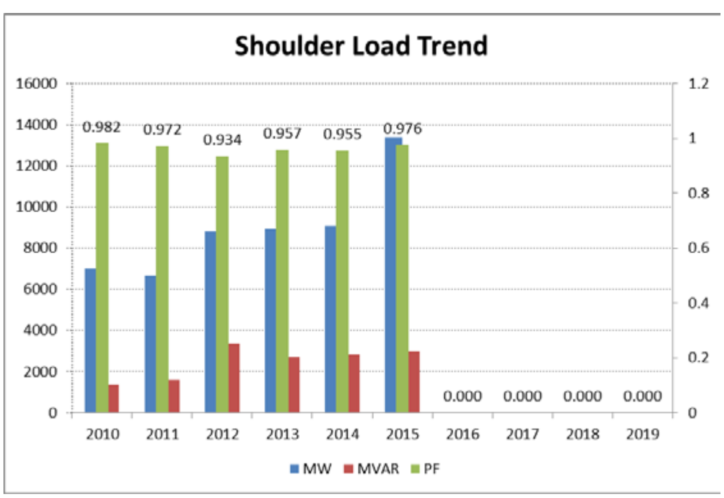


Figure D.27: Duke Energy Progress – Planning – Load Trend (MW) (Shoulder)

Duke Energy Progress – Real Time – Dynamic System (MVAR)

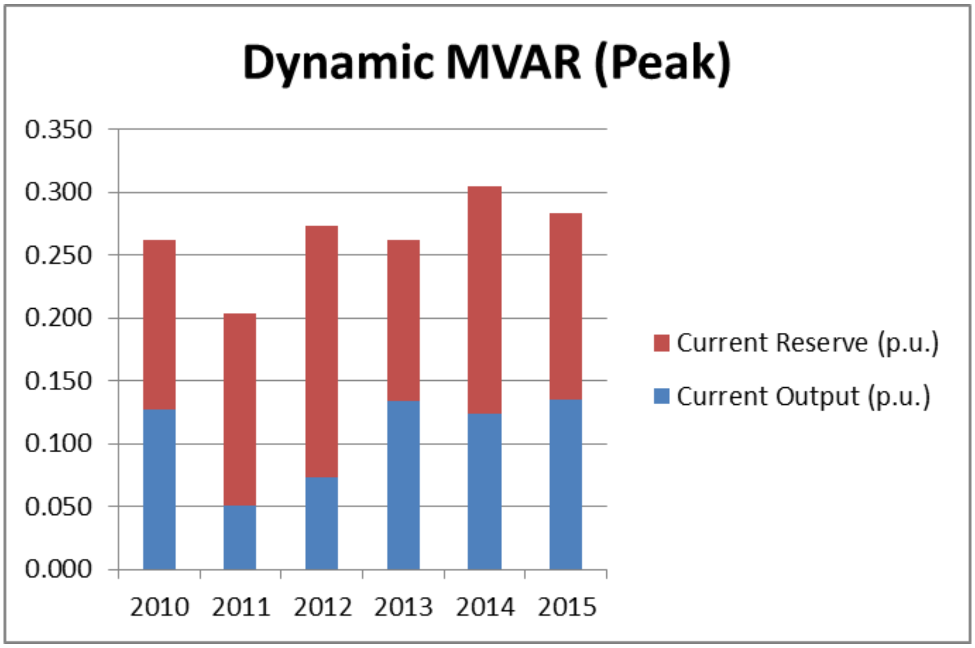


Figure D.28: Duke Energy Progress – Real Time – Dynamic System (MVAR) (Peak)

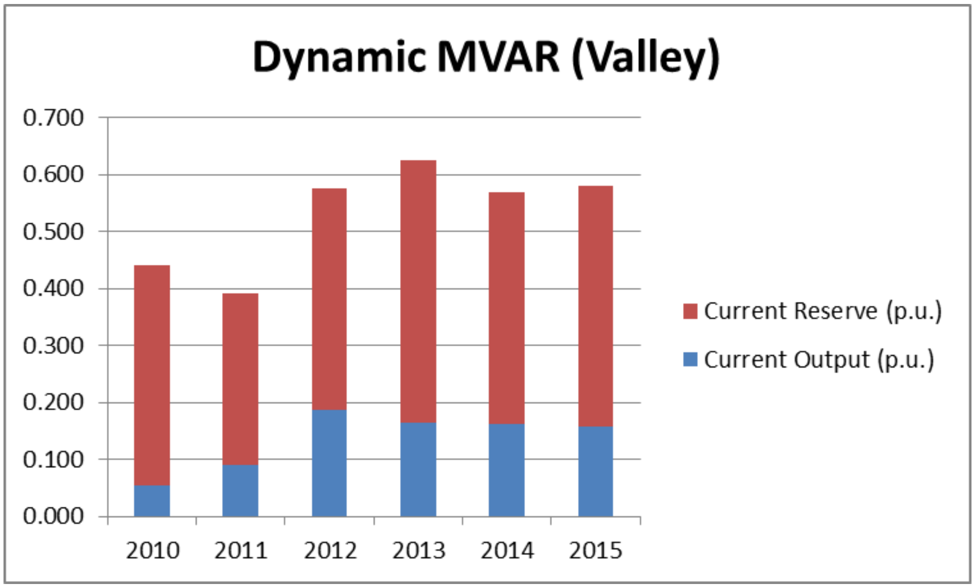


Figure D.29: Duke Energy Progress – Real Time – Dynamic System (MVAR) (Valley)

Duke Energy Progress – Real Time – Static System (MVAR)

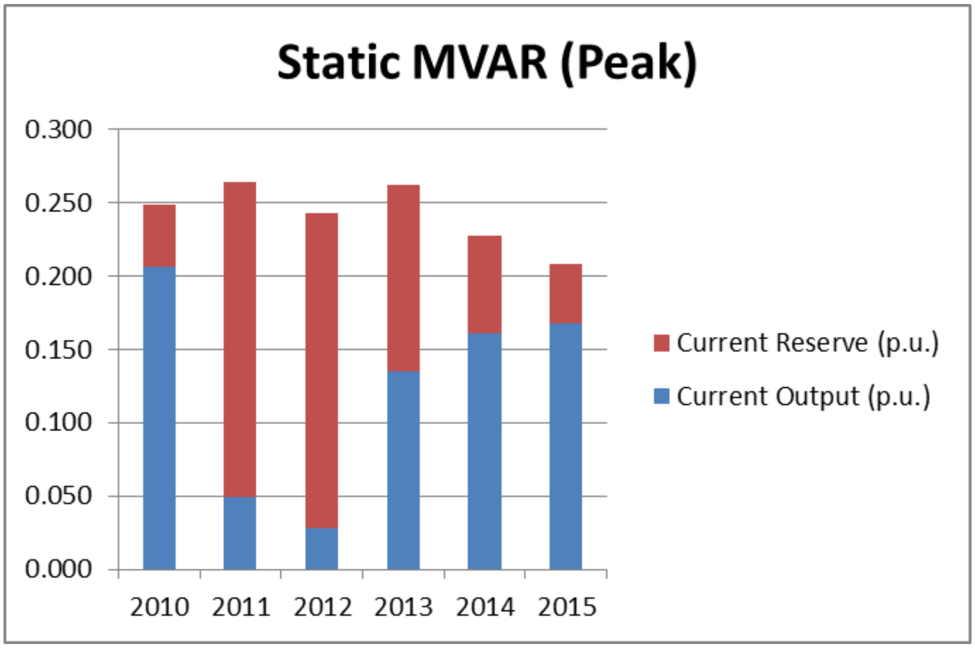


Figure D30: Duke Energy Progress – Real Time – Static System (MVAR) (Peak)

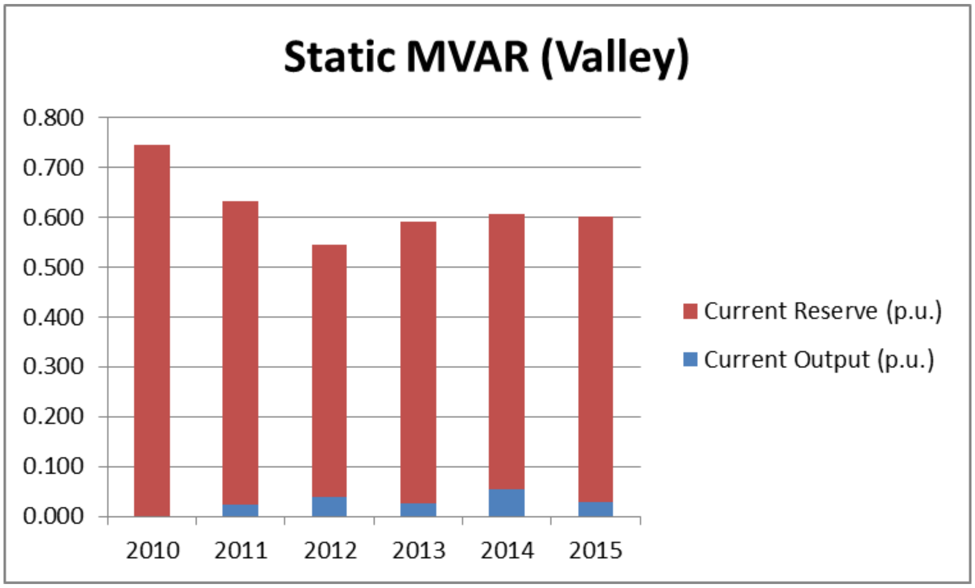


Figure D.31: Duke Energy Progress – Real Time – Static System (MVAR) (Valley)

Duke Energy Progress – Real Time – Load Trend (MW)

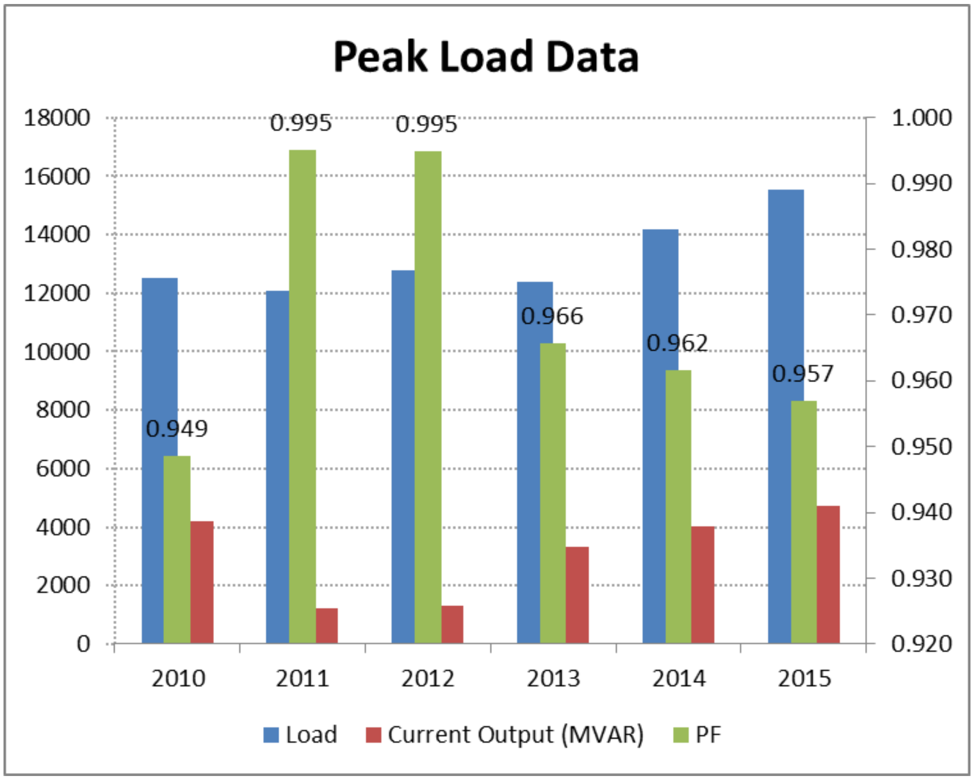


Figure D.32: Duke Energy Progress – Real Time – Load Trend (MW) (Peak)

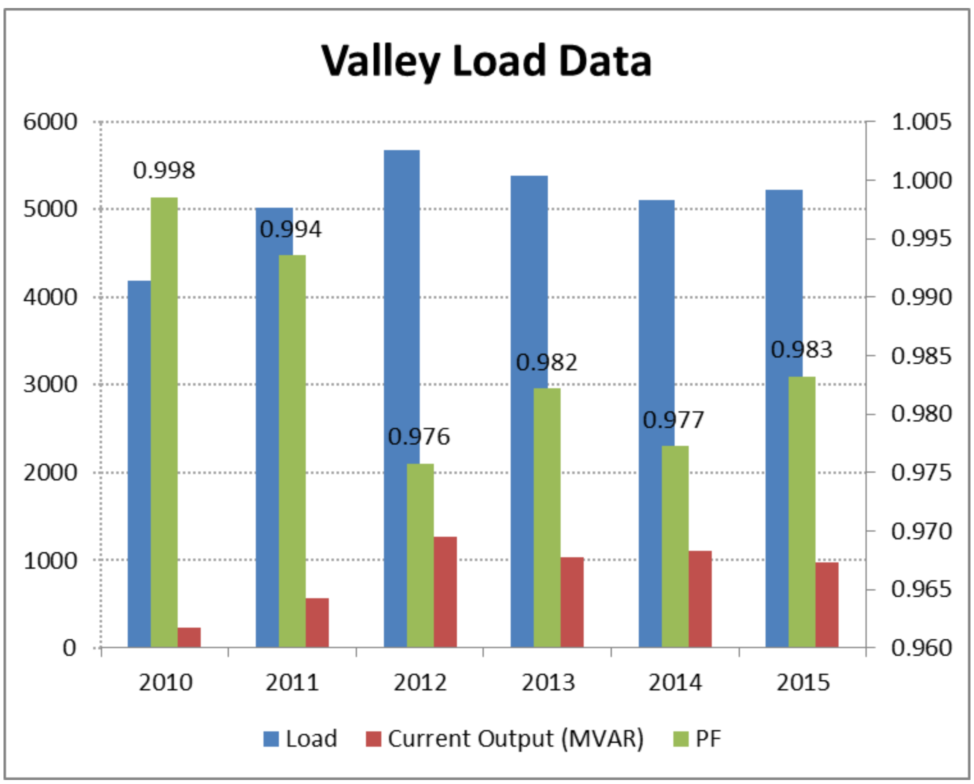


Figure D.33: Duke Energy Progress – Real Time – Load Trend (MW) (Valley)

Duke Energy Florida – Planning – Dynamic System (P.U.)

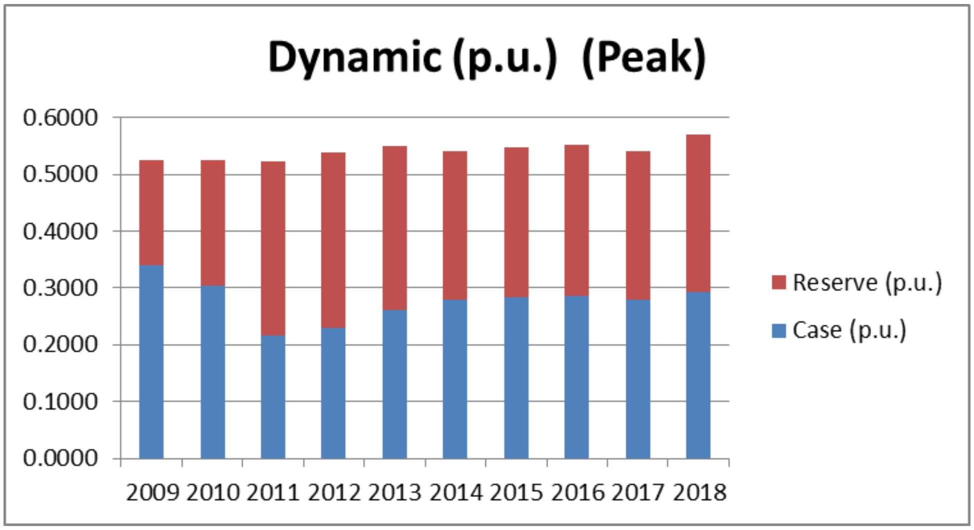


Figure D.34: Duke Energy Florida – Planning – Dynamic (p.u.) (Peak)

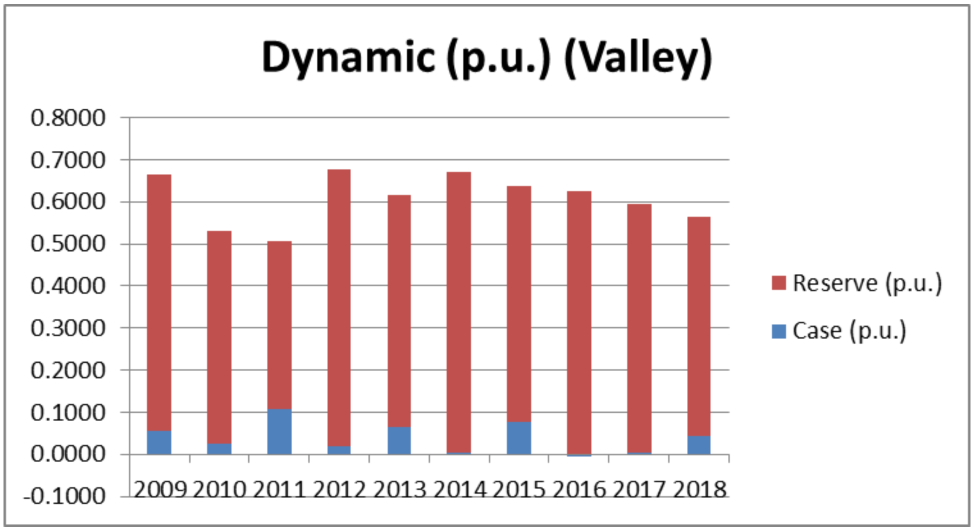


Figure D.35: Duke Energy Florida – Planning – Dynamic (p.u.) (Valley)

Duke Energy Florida – Planning – Static System (p.u.)

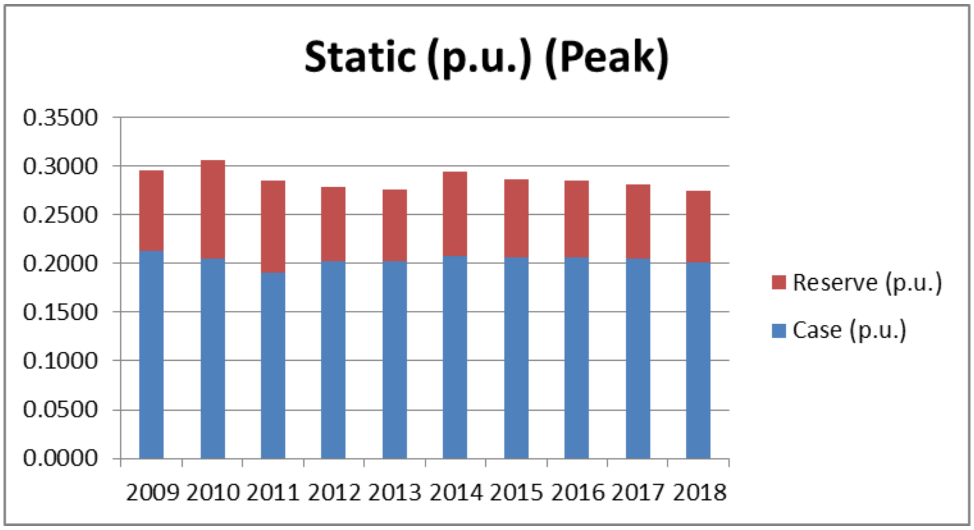


Figure D.36: Duke Energy Florida – Planning – Static System (p.u.) (Peak)

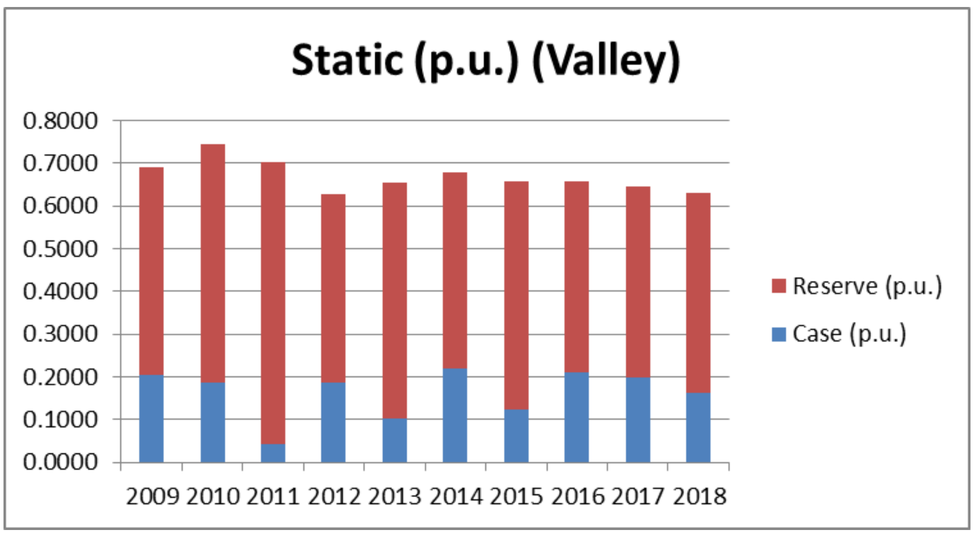


Figure D.37: Duke Energy Florida – Planning – Static System (p.u.) (Valley)

Duke Energy Florida – Planning – Load Trend (MW)

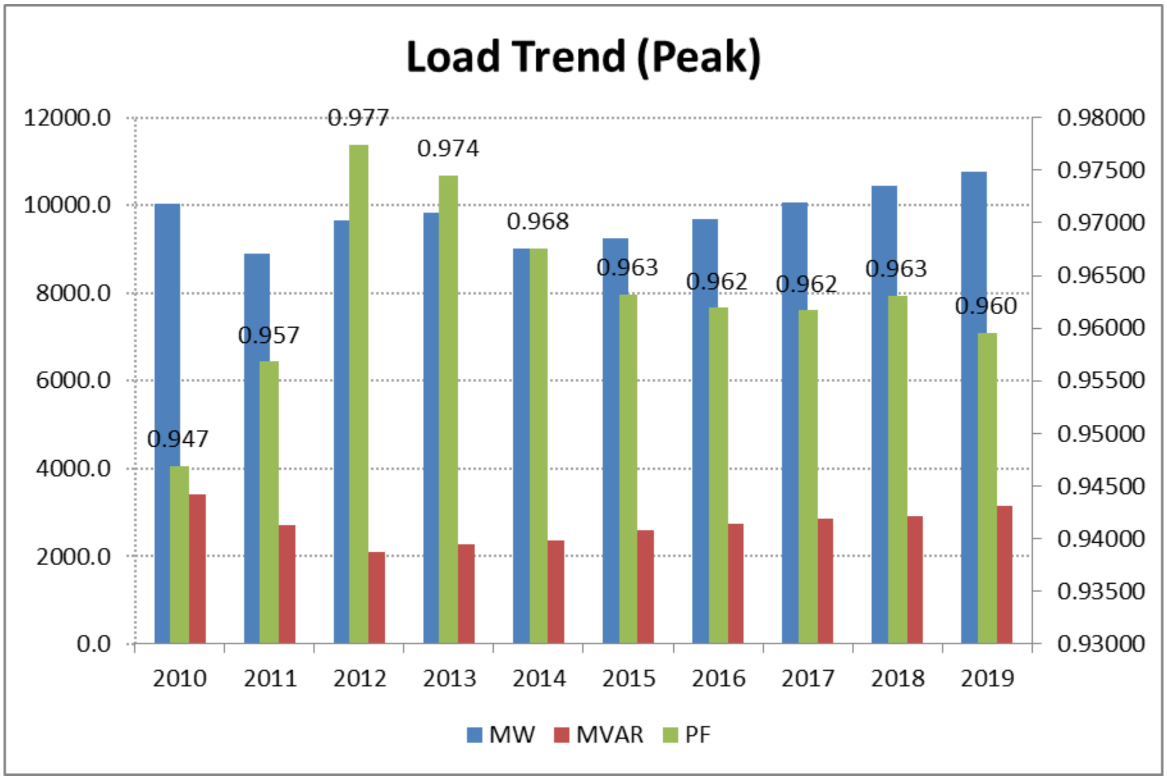


Figure D.38: Duke Energy Florida – Planning – Load Trend (MW) (Peak)

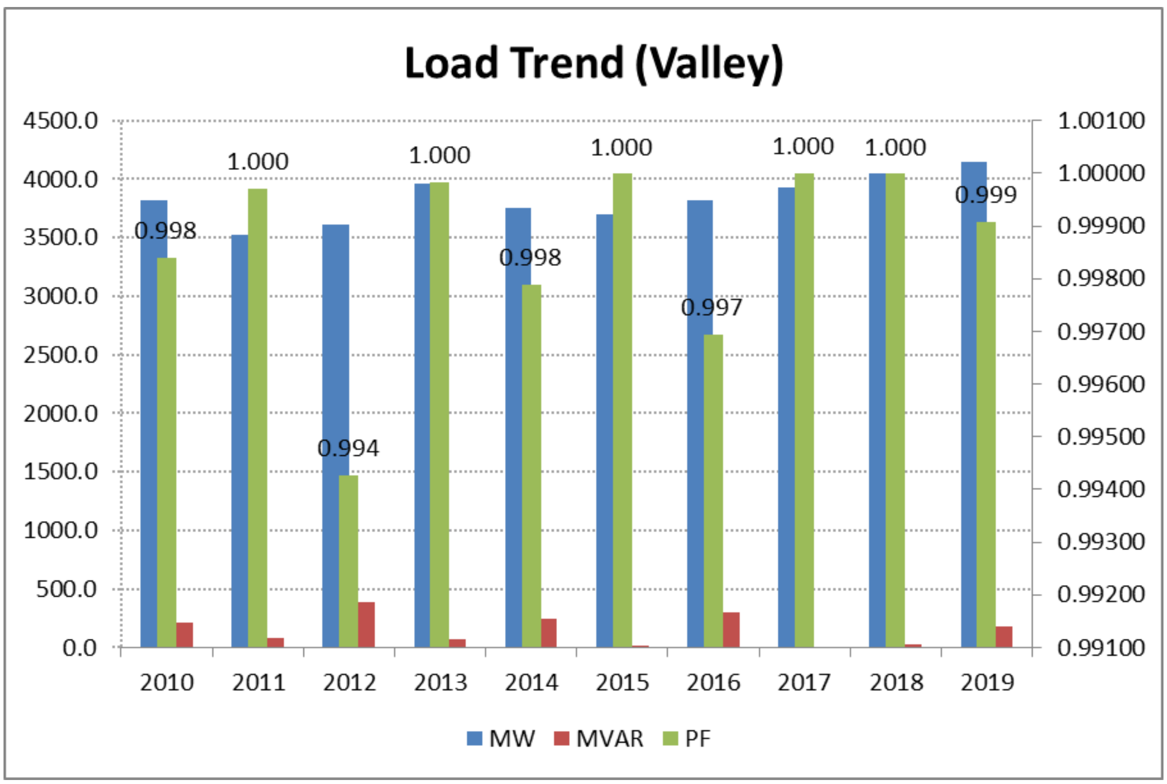


Figure D.39: Duke Energy Florida – Planning – Load Trend (MW) (Valley)

ISO-NE – Planning – Dynamic System (P.U.)

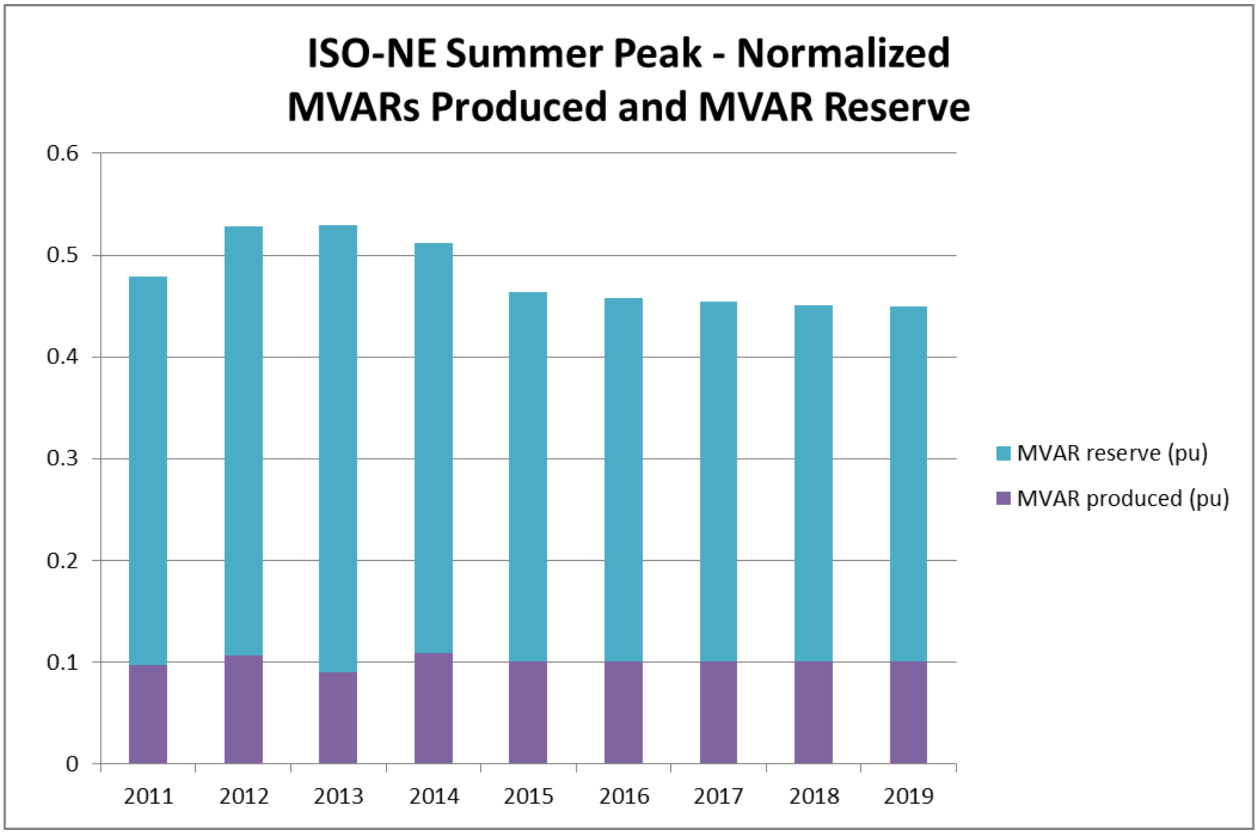


Figure D.40: ISO-NE – Planning – Dynamic System (p.u.) (Summer Peak)

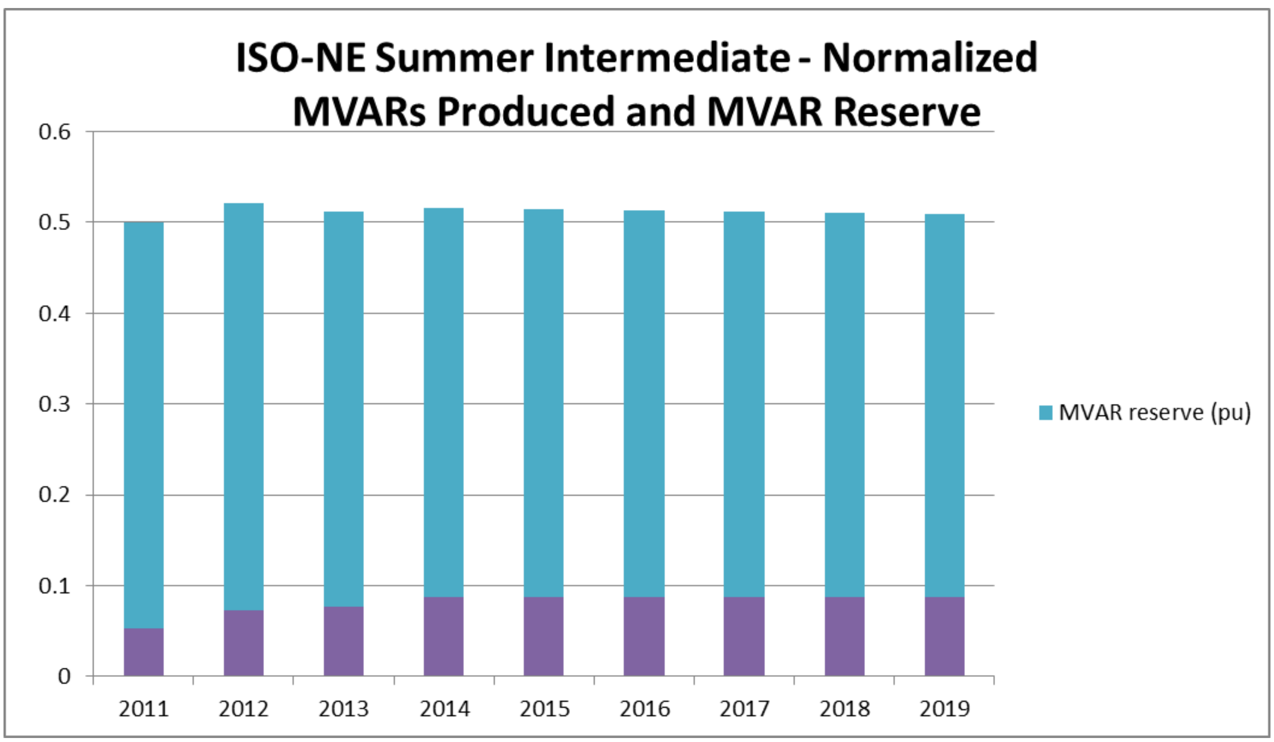


Figure D.41: ISO-NE – Planning – Dynamic System (p.u.) (Summer Intermediate)

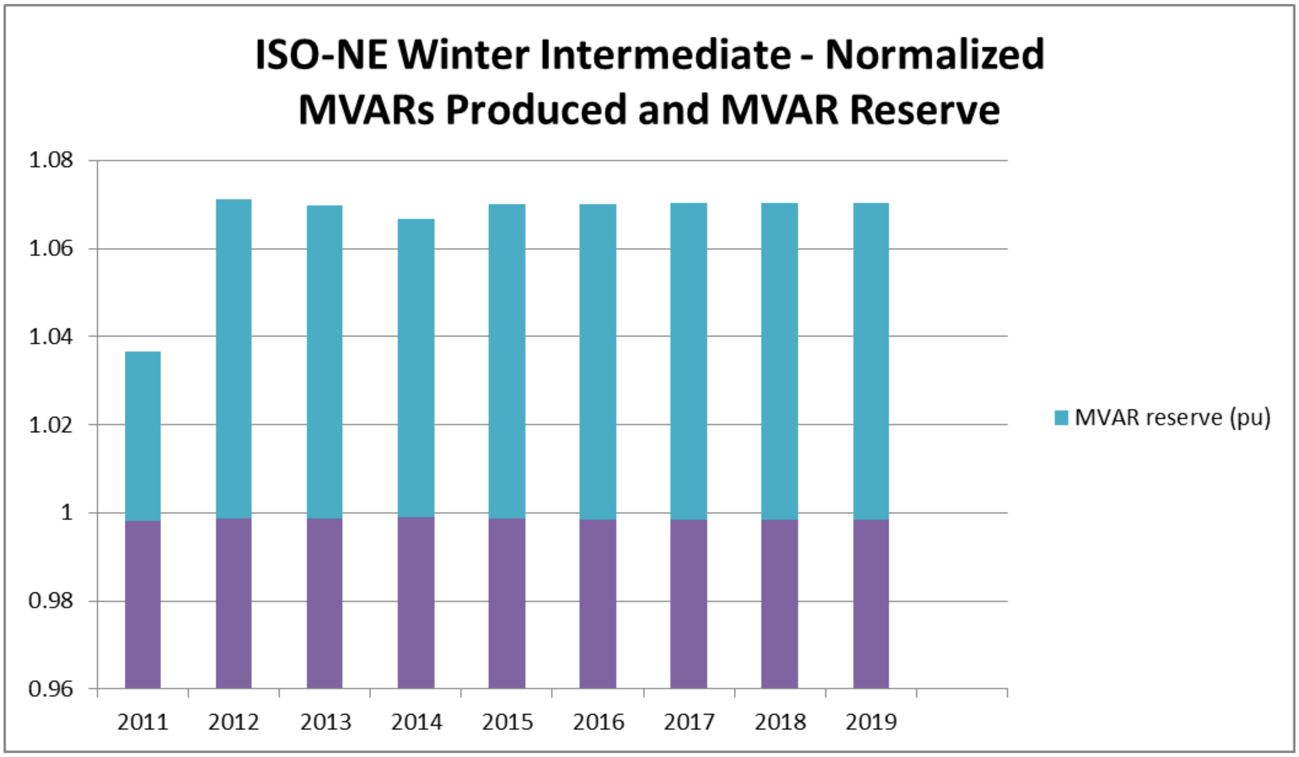


Figure D.42: ISO-NE – Planning – Dynamic System (p.u.) (Winter Intermediate)

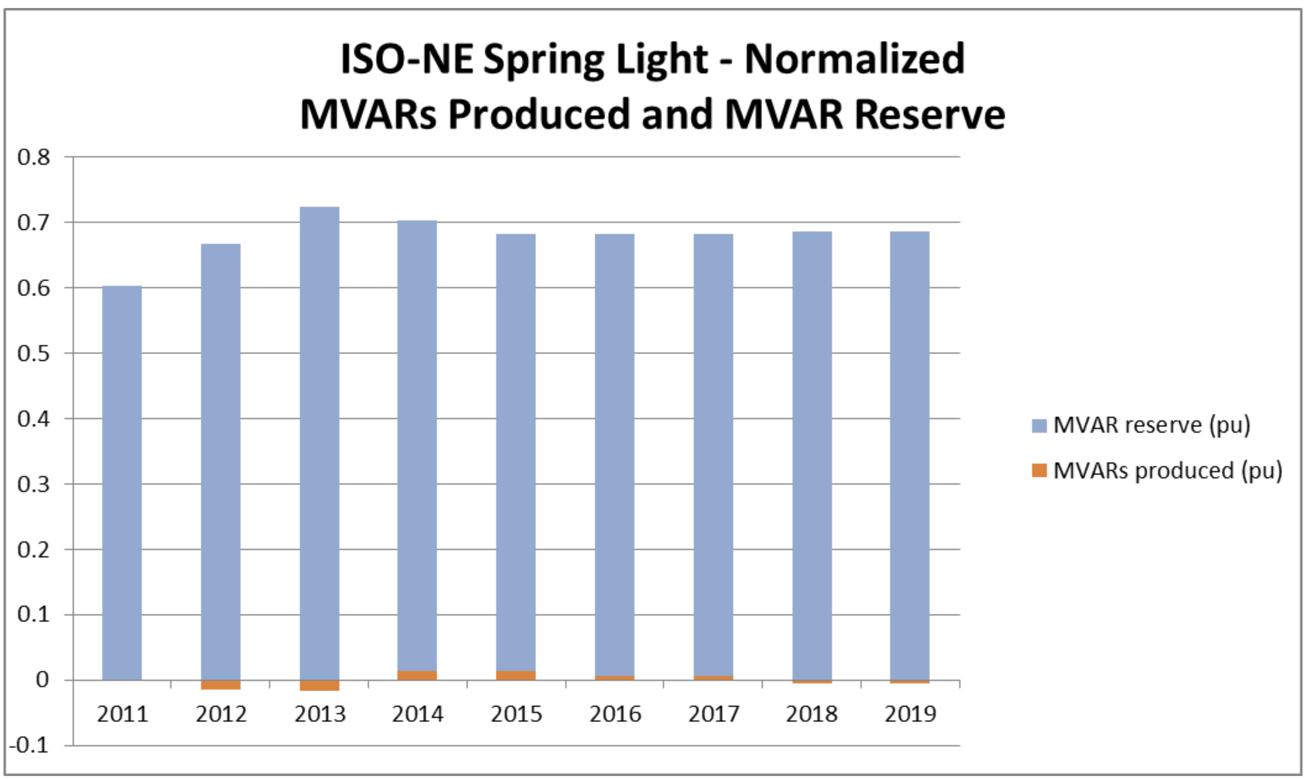


Figure D.43: ISO-NE – Planning – Dynamic System (p.u.) (Spring Light)

ISO-NE – Planning – Static System (p.u.)

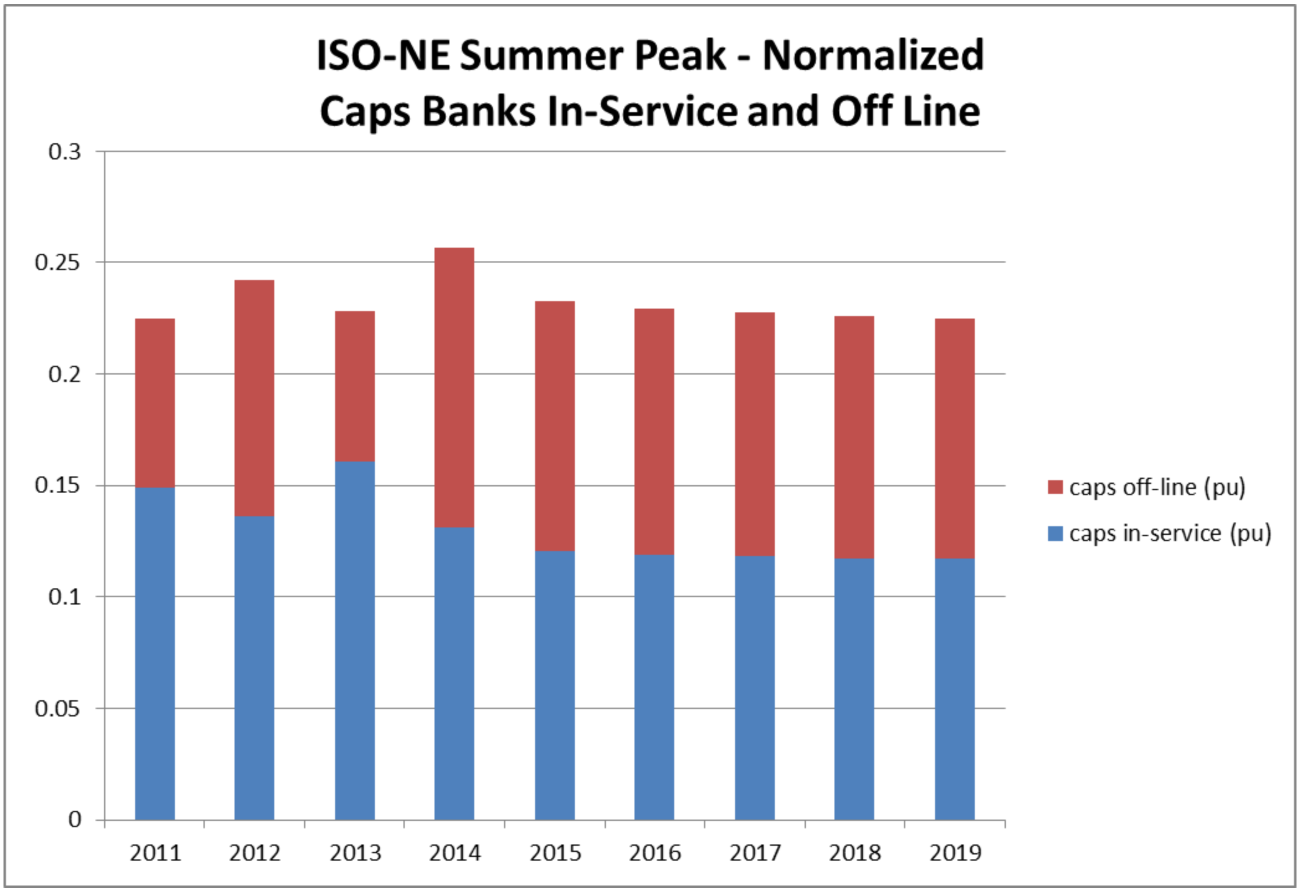


Figure D.44: ISO-NE – Planning – Static System (p.u.) (Summer Peak)

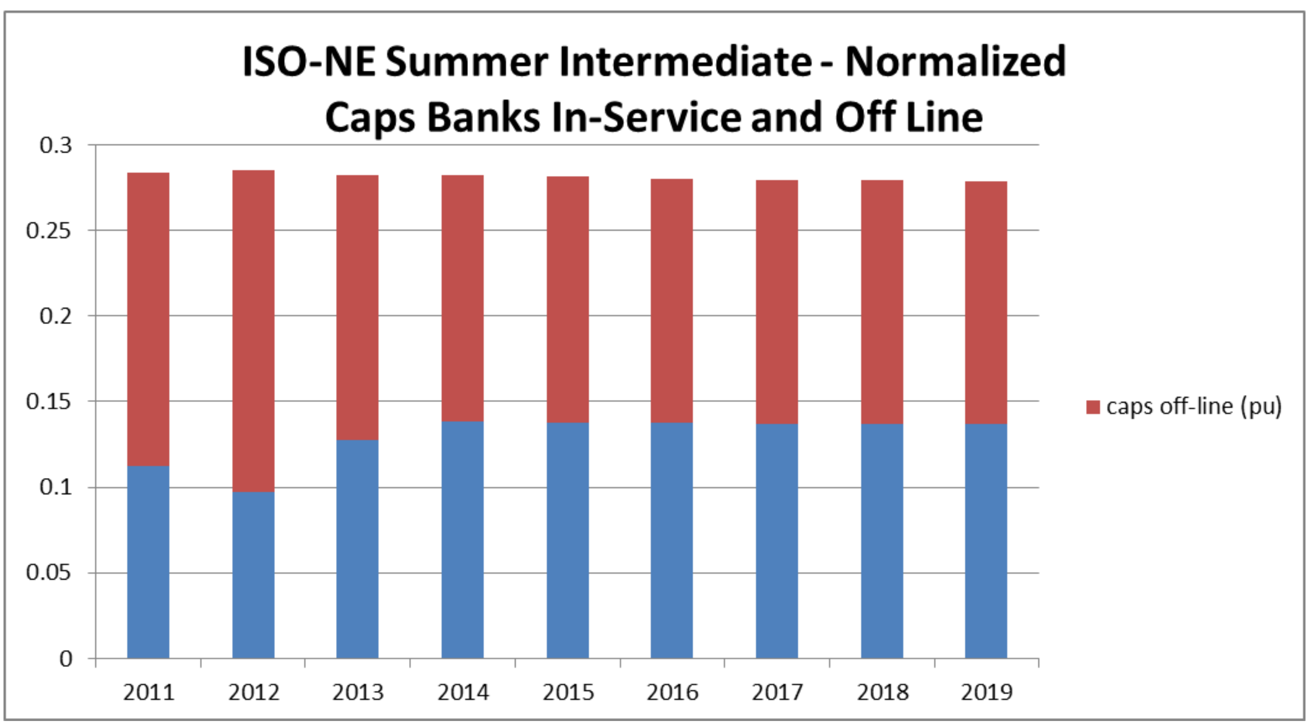


Figure D.45: ISO-NE – Planning – Static System (p.u.) (Summer Intermediate)

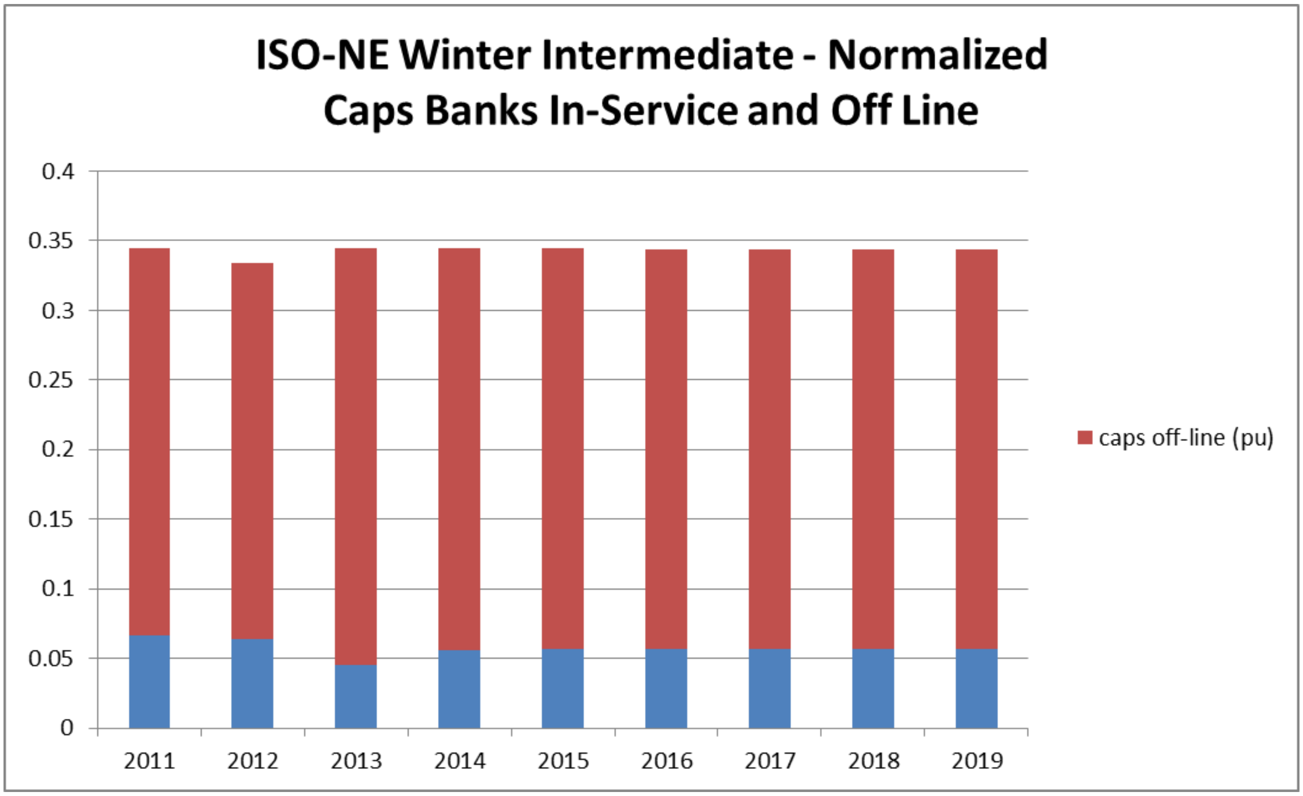


Figure D.46: ISO-NE – Planning – Dynamic System (p.u.) (Winter Intermediate)

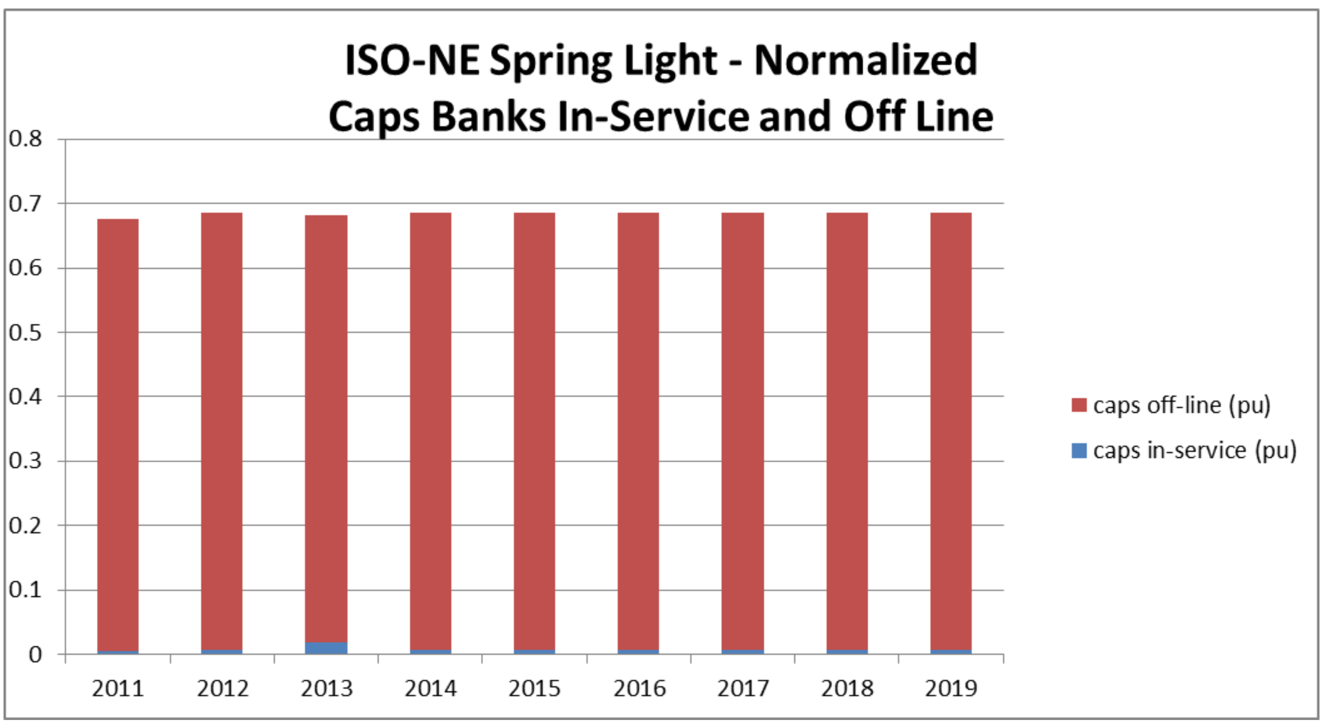


Figure D.47: ISO-NE – Planning – Dynamic System (p.u.) (Spring Light)

ISO-NE – Planning – Load Trend (MW)

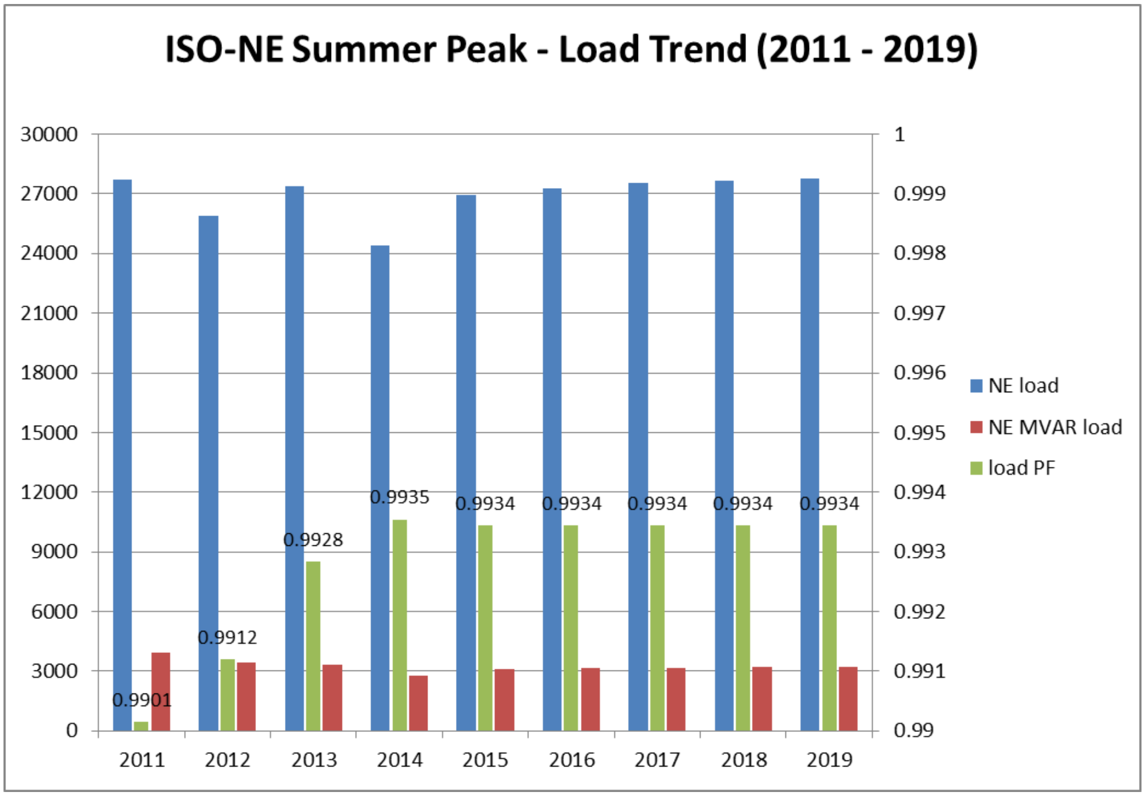


Figure D.48: ISO-NE – Planning – Load Trend (MW) (Summer Peak)

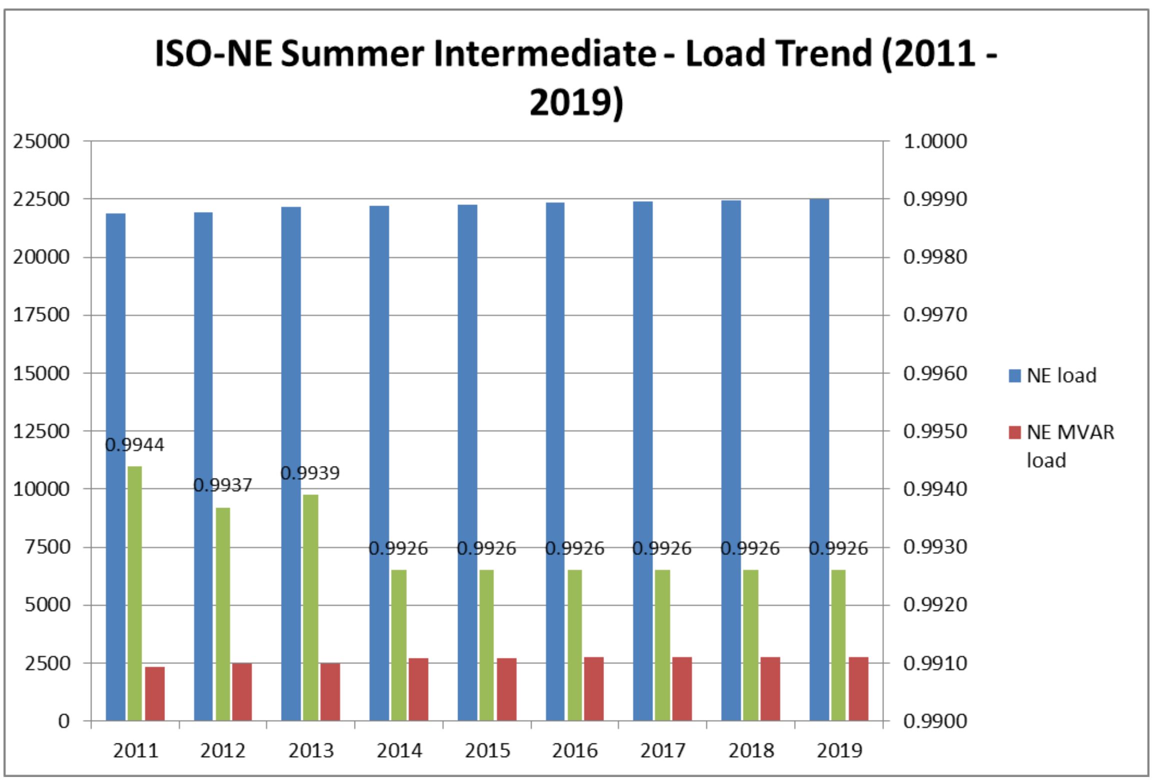


Figure D.49: ISO-NE – Planning – Load Trend (MW) (Summer Intermediate)

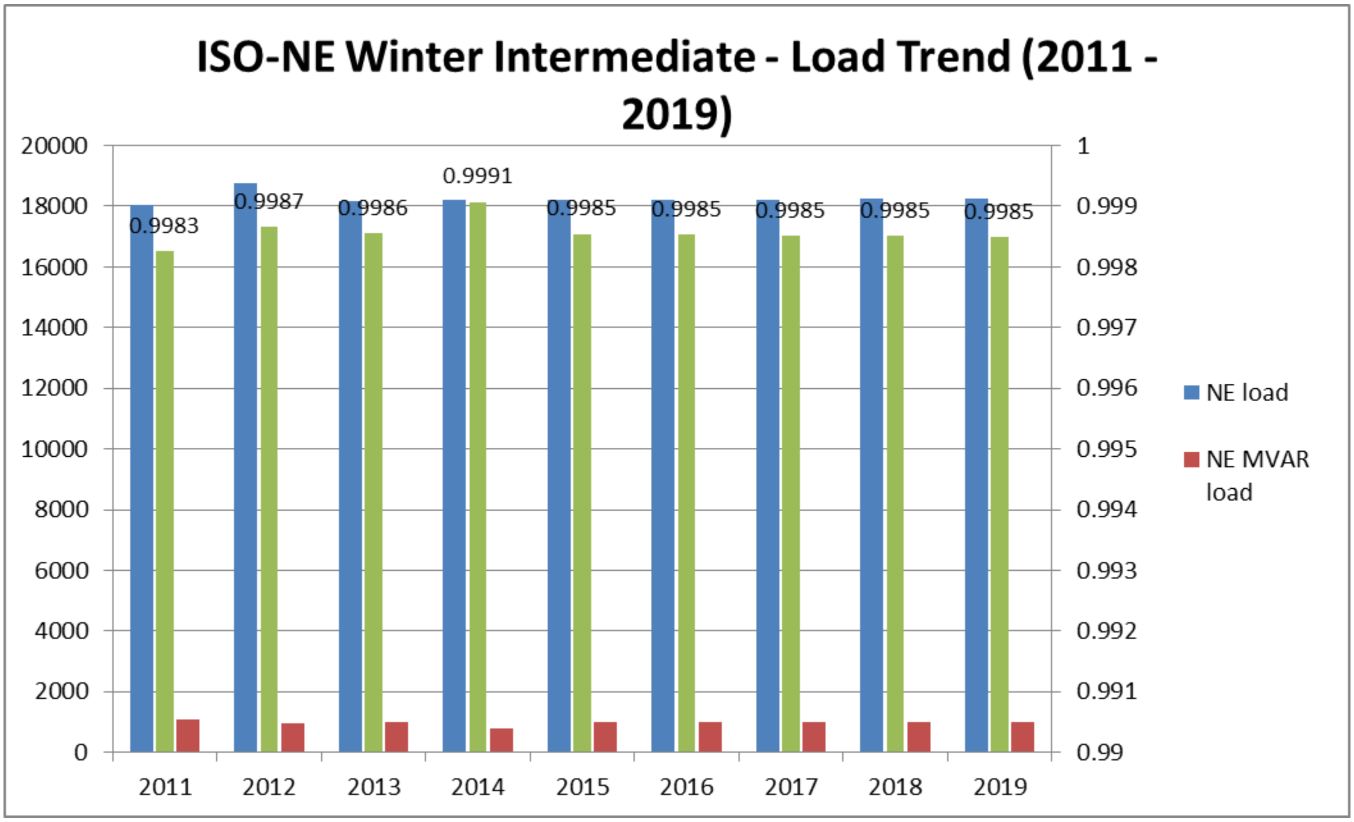


Figure D.50: ISO-NE – Planning – Load Trend (MW) (Winter Intermediate)

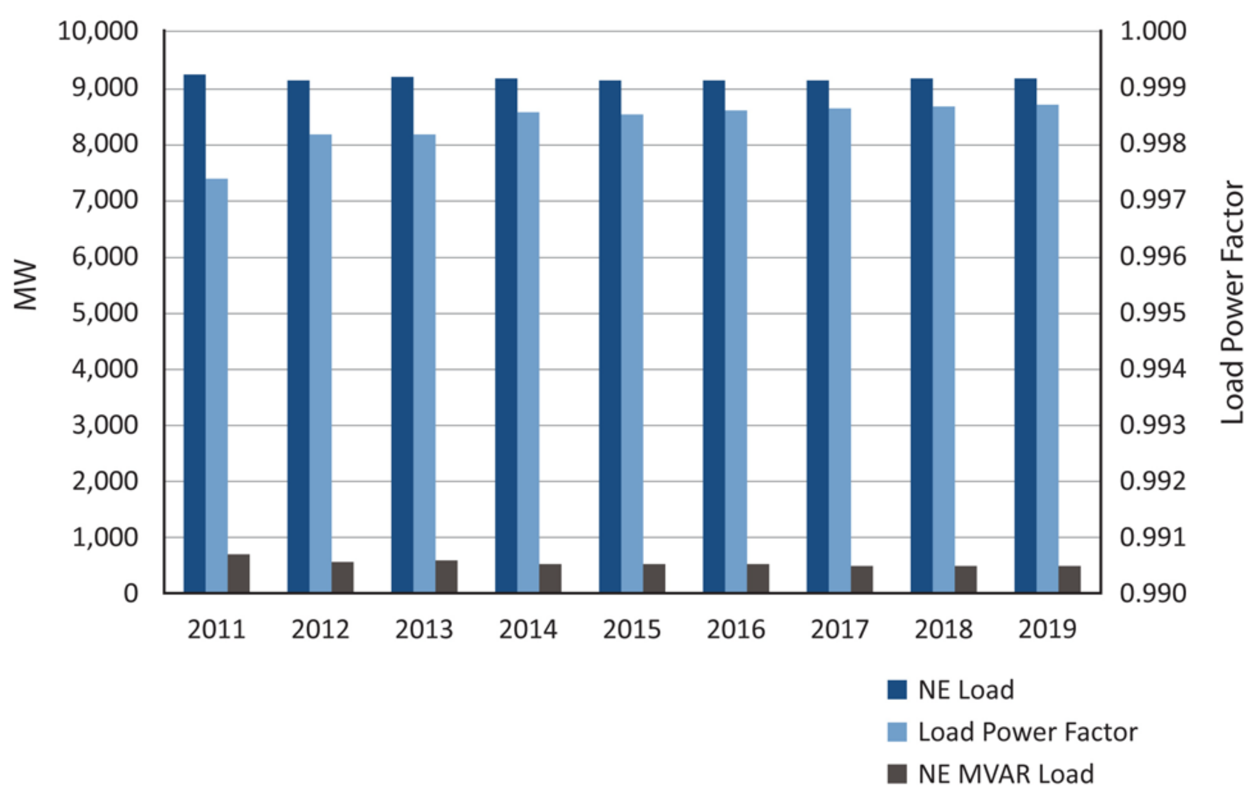


Figure D.51: ISO-NE – Planning – Load Trend (MW) (Spring Light)

ERCOT – Planning – Dynamic System (p.u.)

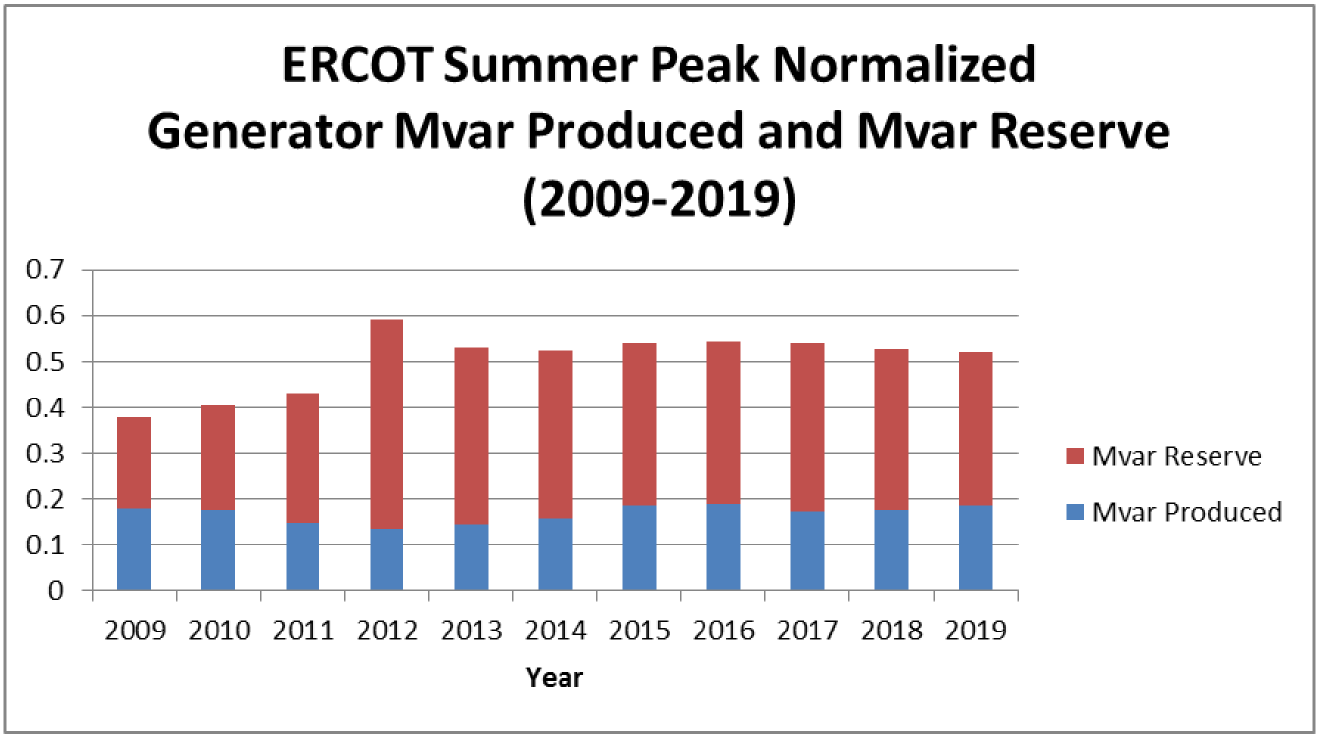


Figure D.52: ERCOT – Planning – Dynamic System (p.u.) (Summer Peak)

ERCOT – Planning – Static System (p.u.)

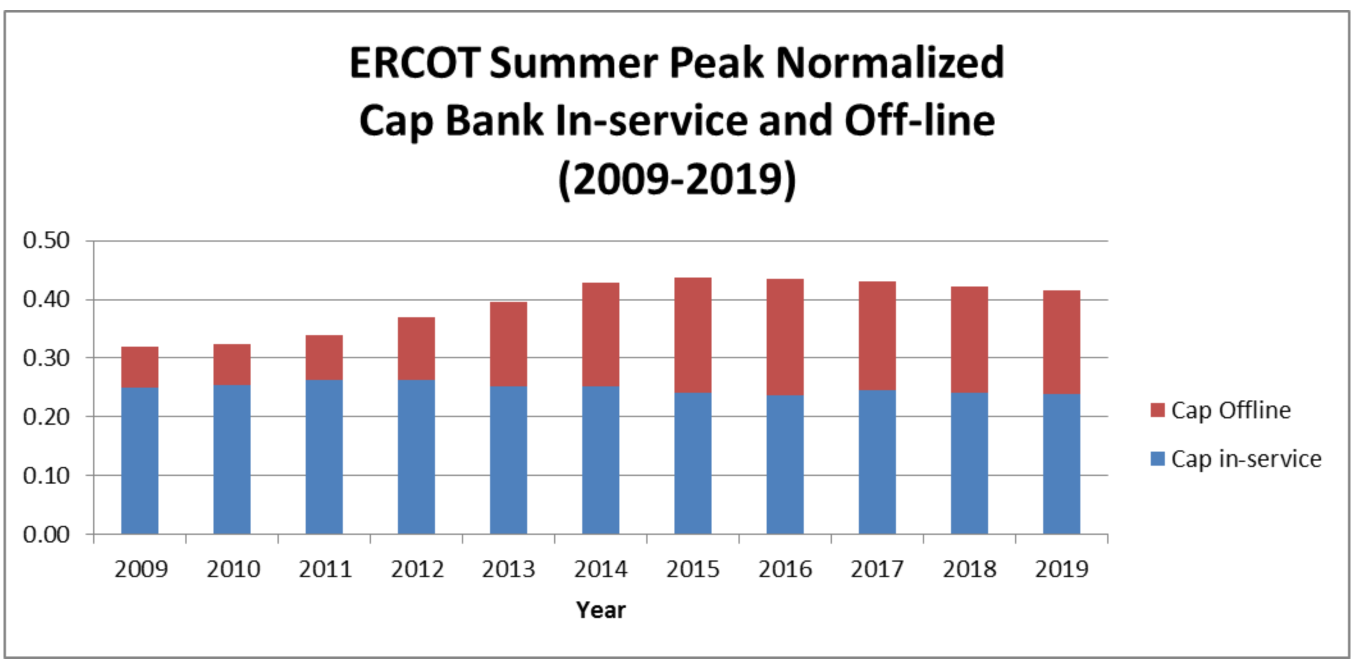


Figure D.53: ERCOT – Planning – Static System (p.u.) (Summer Peak)

ERCOT – Planning – Load Trend (MW)

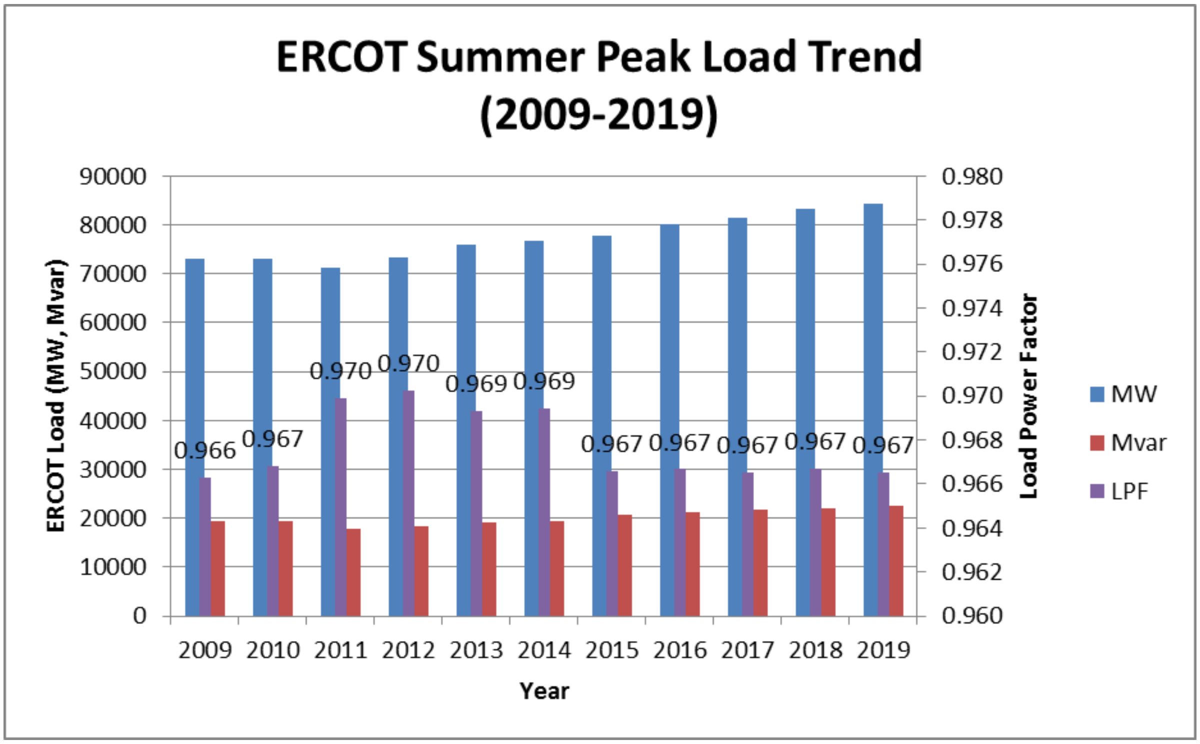


Figure D.54: ERCOT – Planning – Dynamic System (p.u.) (Summer Peak)

IESO – Planning – Dynamic System (P.U.)

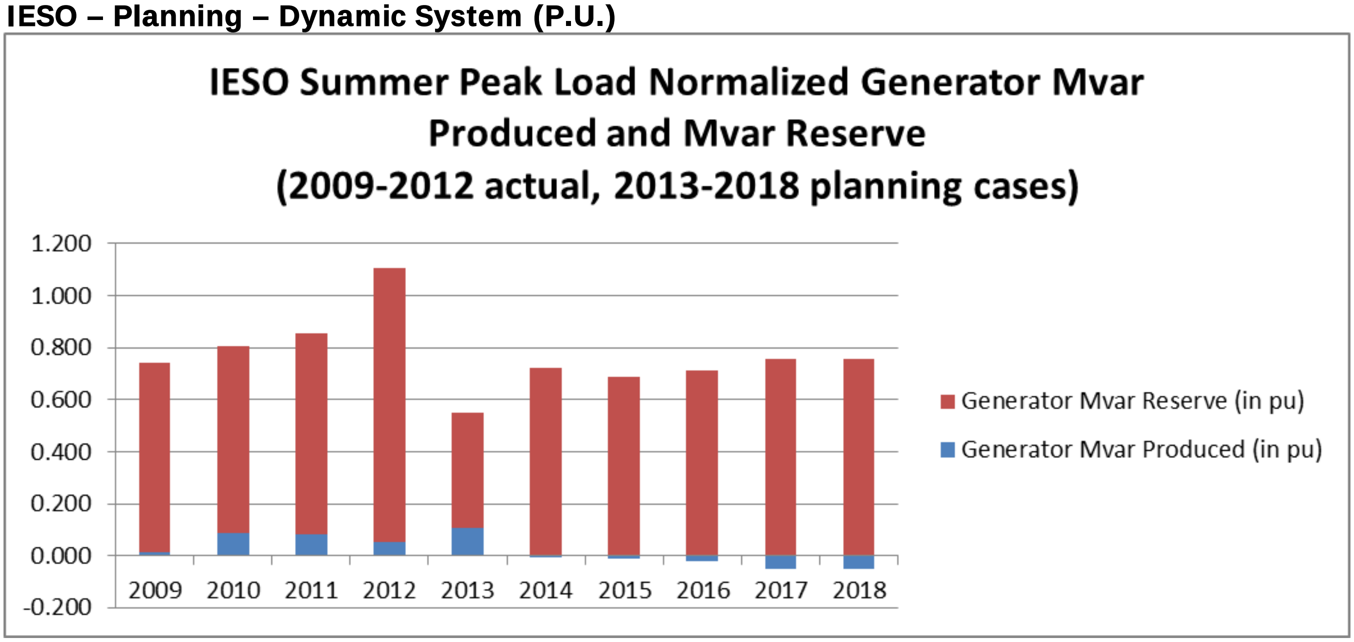


Figure D.55: IESO – Planning – Dynamic System (p.u.) (Summer Peak)

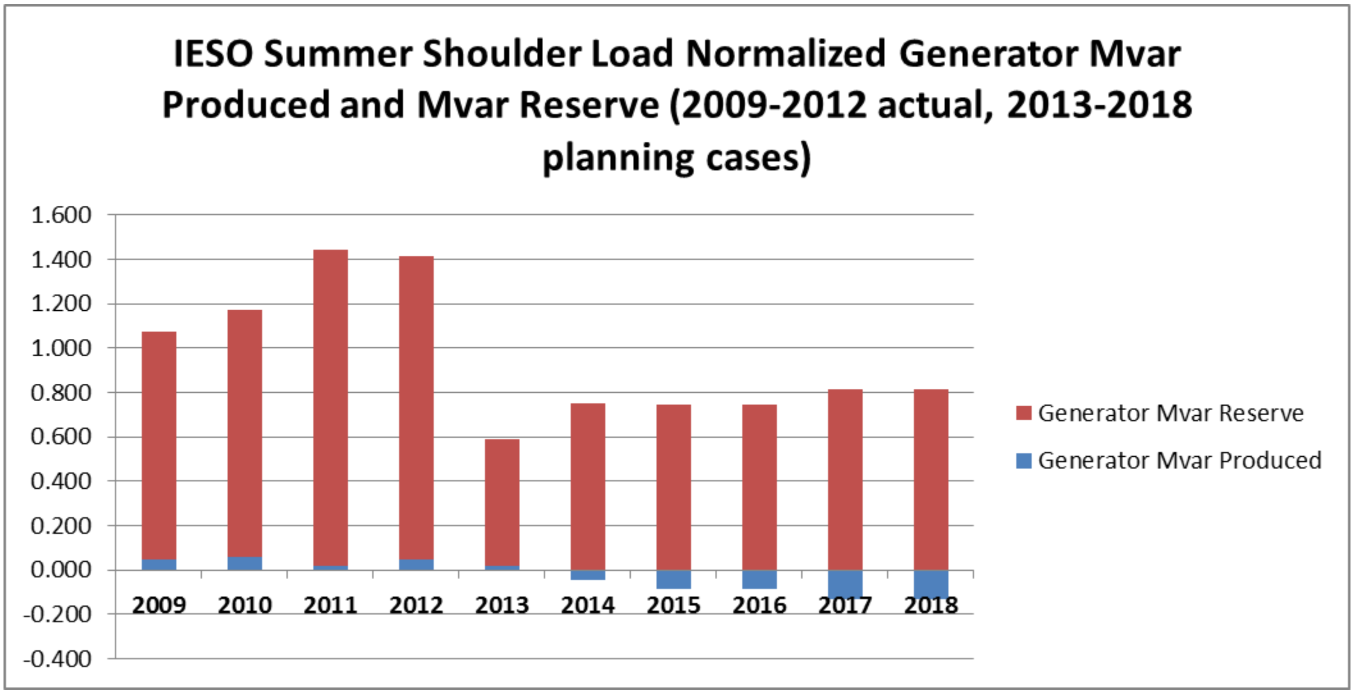


Figure D.56: IESO – Planning – Dynamic System (p.u.) (Summer Shoulder)

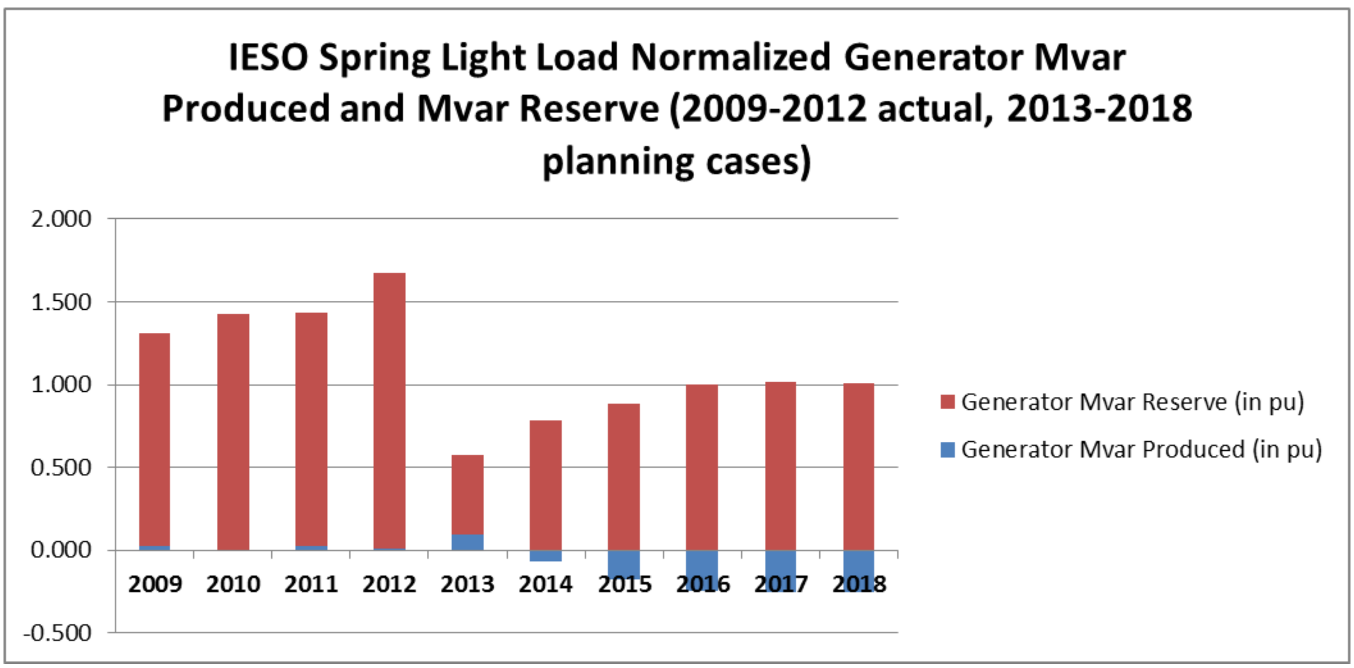


Figure D.57: IESO – Planning – Dynamic System (p.u.) (Spring Light Load)

IESO – Planning – Static System (p.u.)

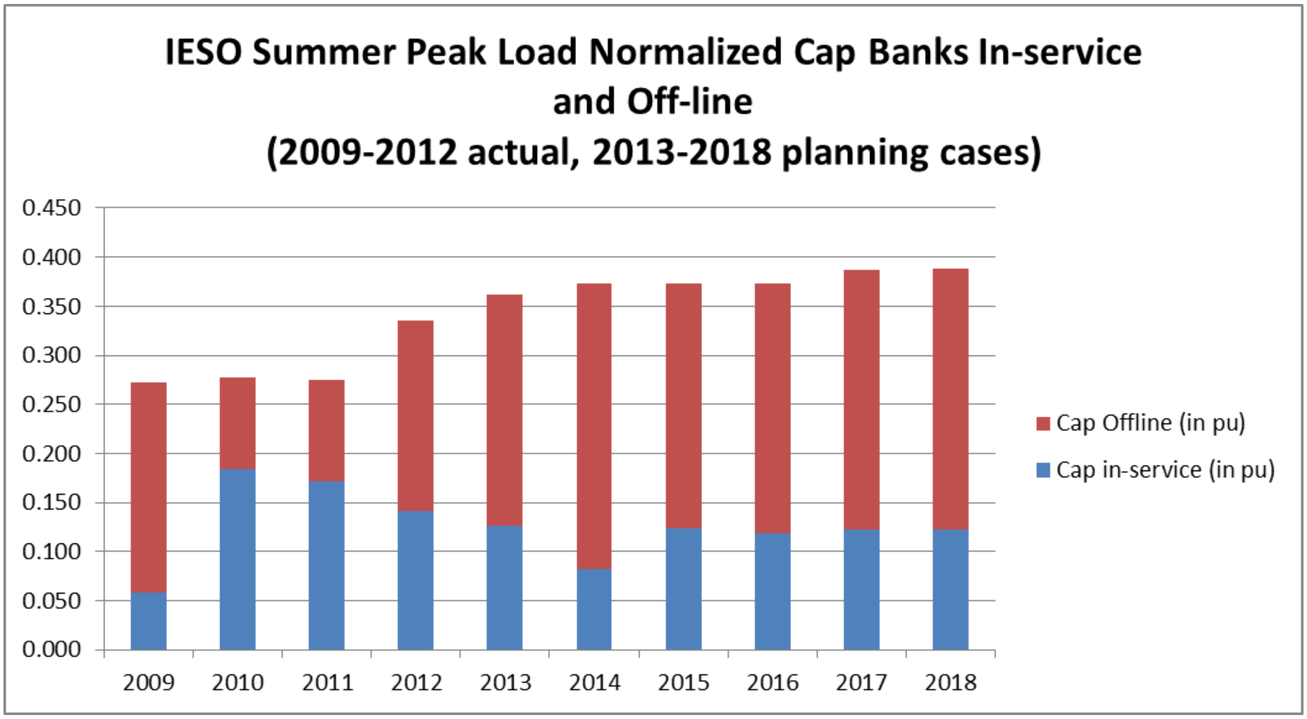


Figure D.58: IESO – Planning – Static System (p.u.) (Summer Peak)

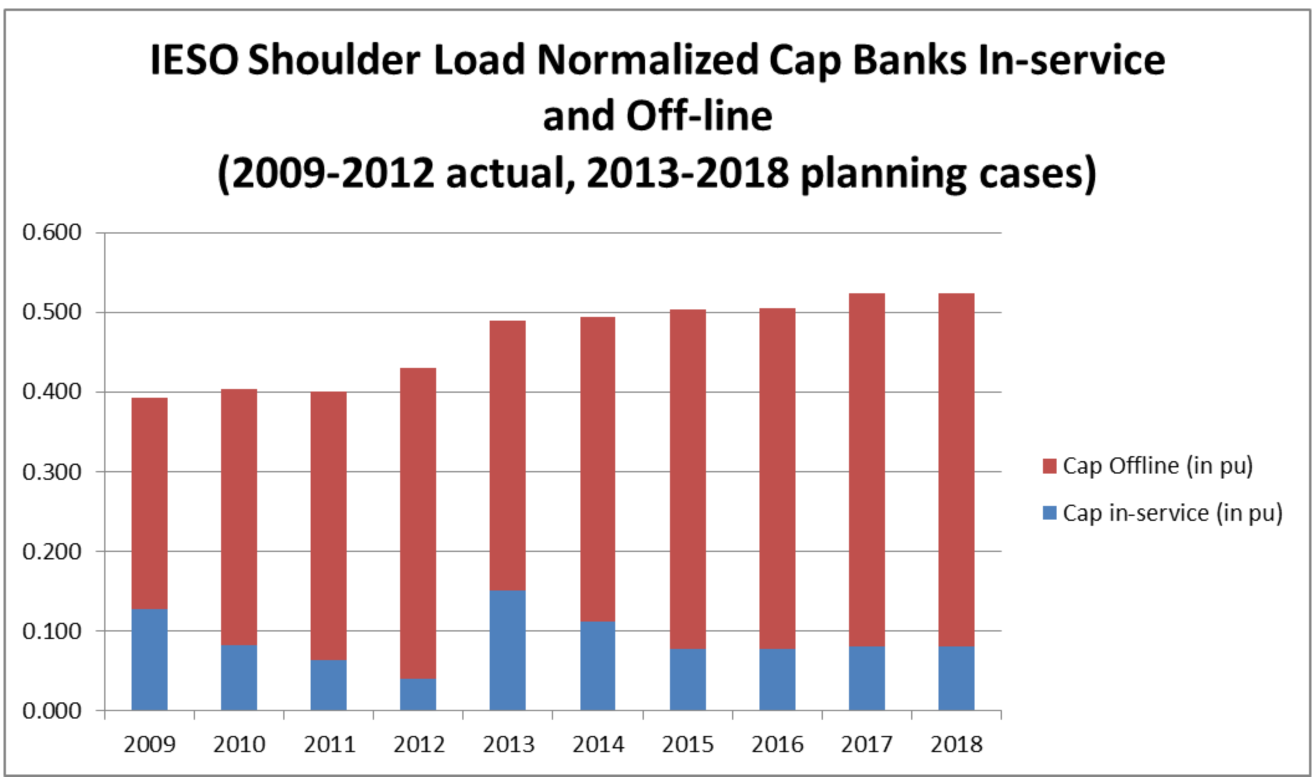


Figure D.59: IESO – Planning – Static System (p.u.) (Shoulder Load)

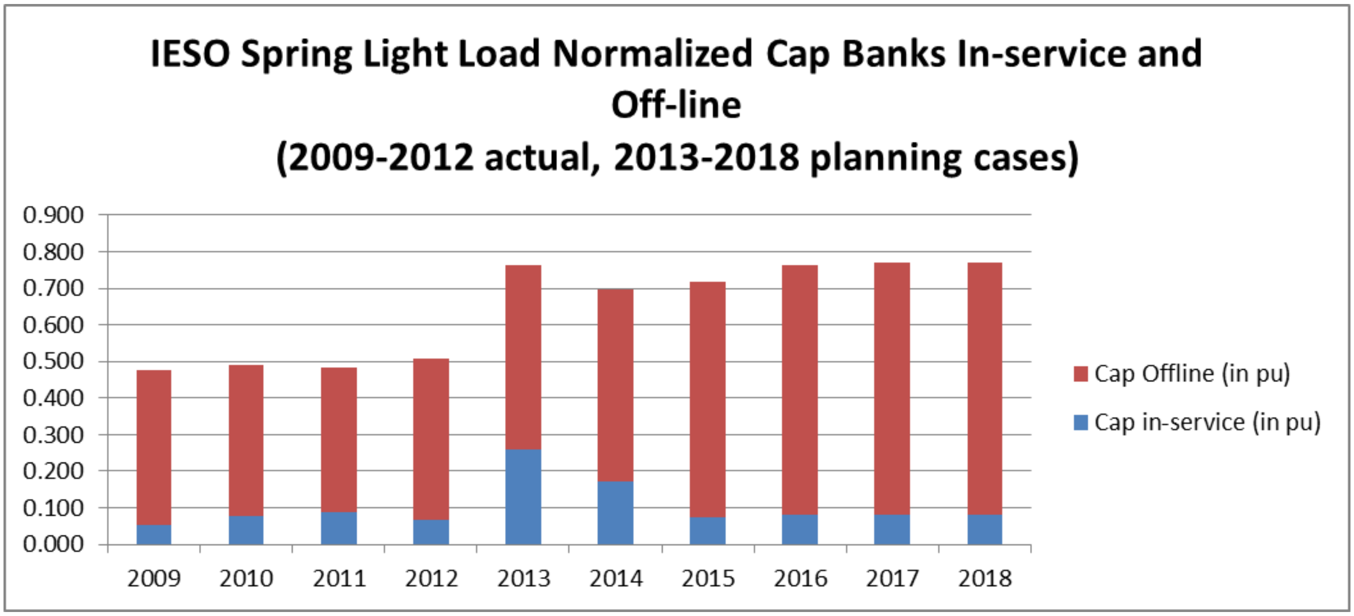


Figure D.60: IESO – Planning – Static System (p.u.) (Spring Light Load)

IESO – Planning – Load Trend (MW)

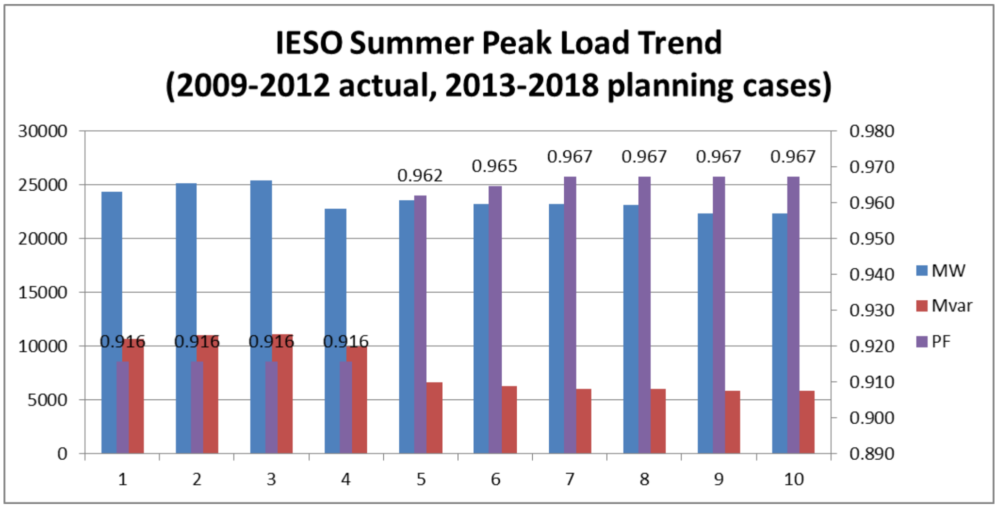


Figure D.61: IESO – Planning – Load Trend (MW) (Peak)

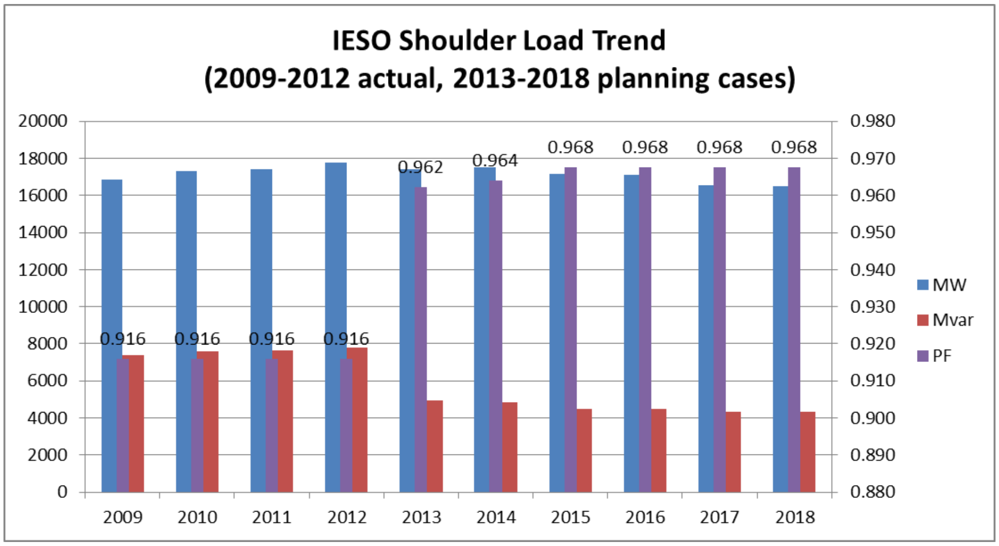


Figure D.62: IESO – Planning – Load Trend (MW) (Shoulder)

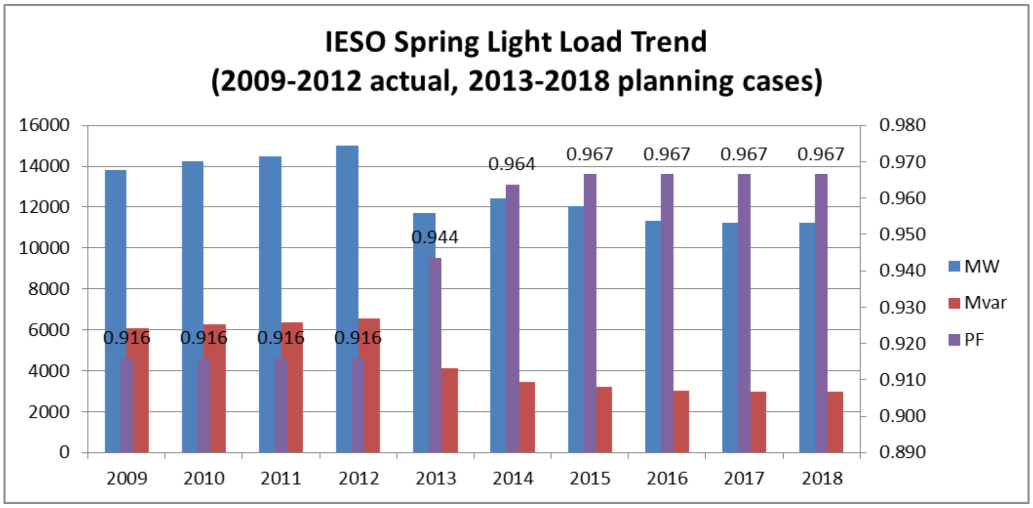


Figure D.63: IESO – Planning – Load Trend (MW) (Spring Light Load)

Hydro-Quebec – Planning – Dynamic System (p.u.)

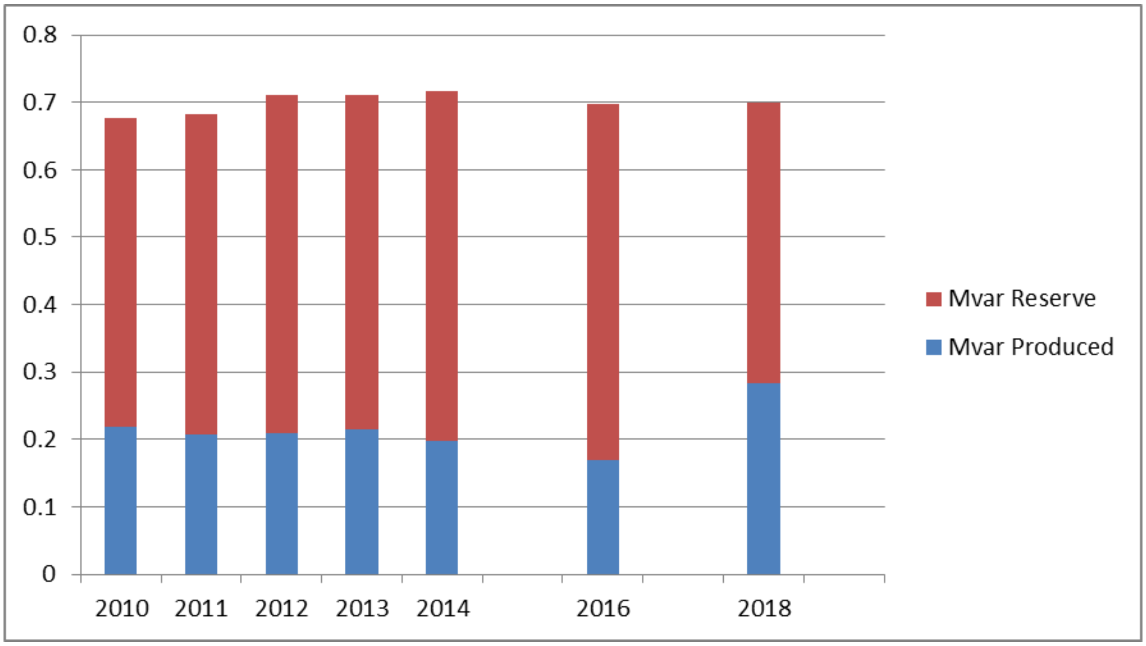


Figure D.64: Hydro-Quebec – Planning – Dynamic (p.u)

Hydro-Quebec – Planning – Static System (P.U.)

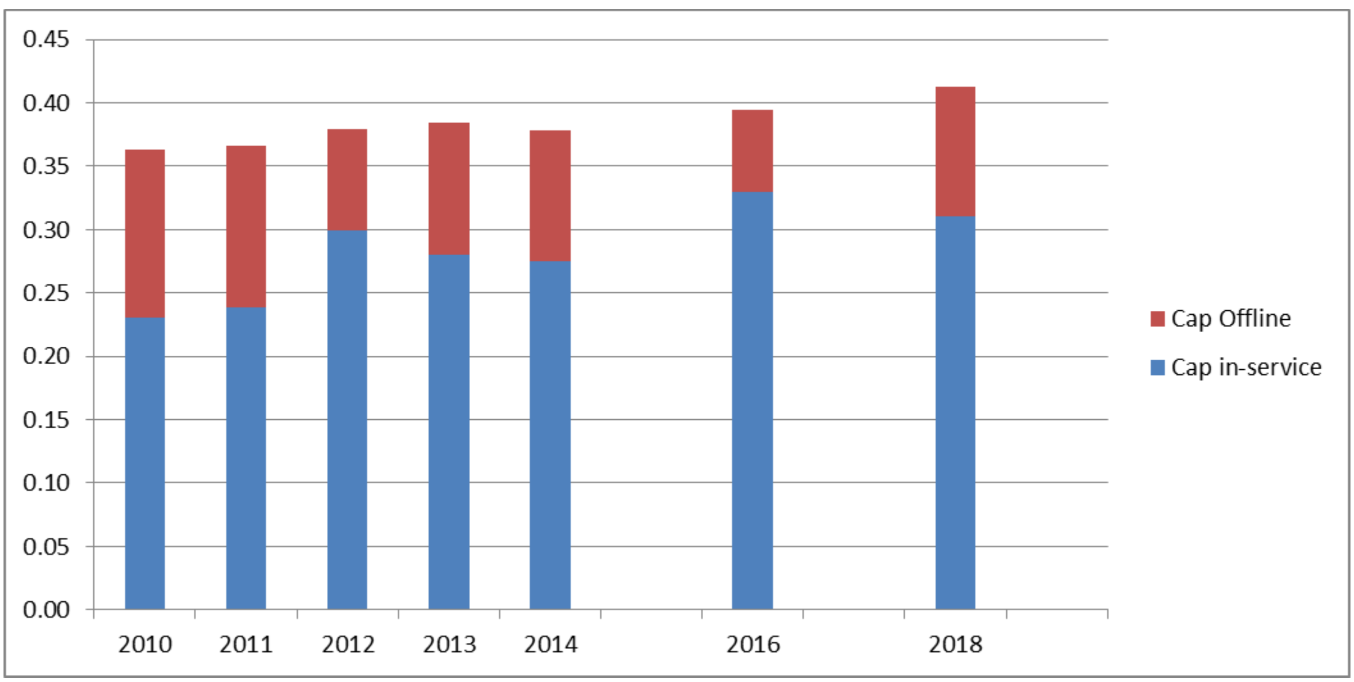


Figure D.65: Hydro-Quebec – Planning – Static System (p.u)

Hydro-Quebec – Planning – Load Trend (MW)

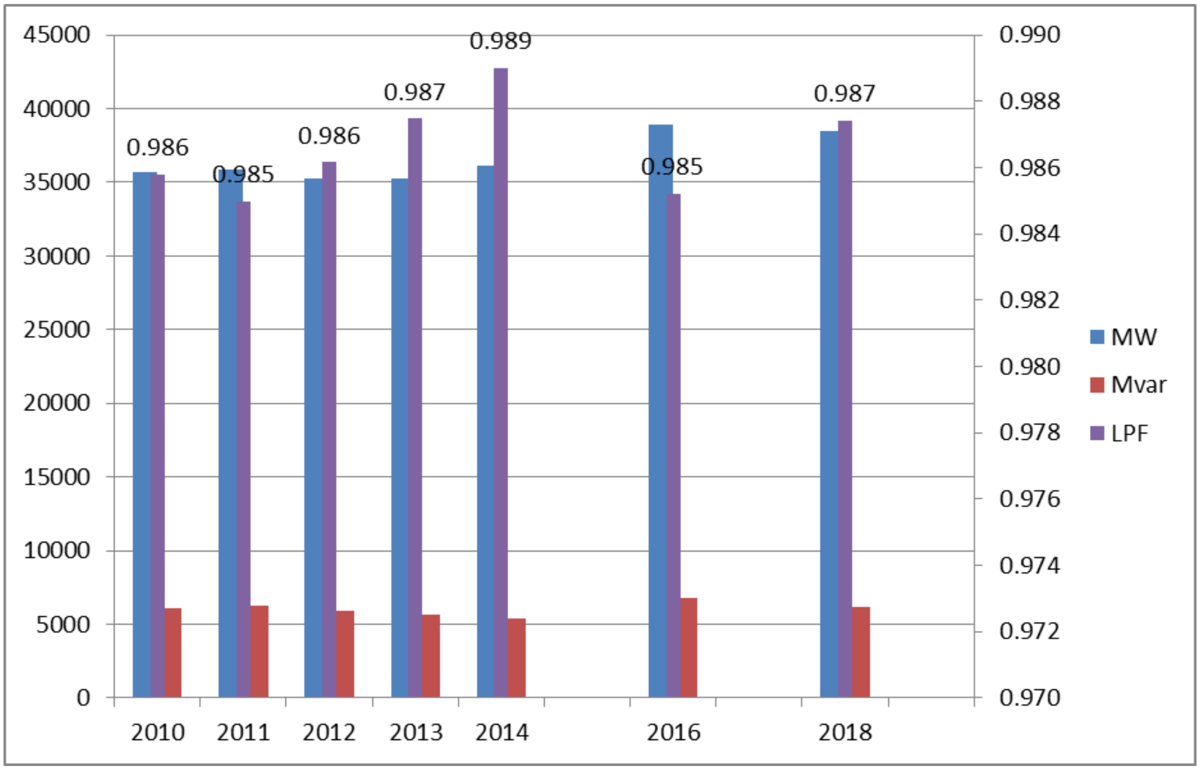


Figure D.66: Hydro-Quebec – Planning – Load Trend (MW)

Southern Company – Planning – Dynamic System (P.U.)

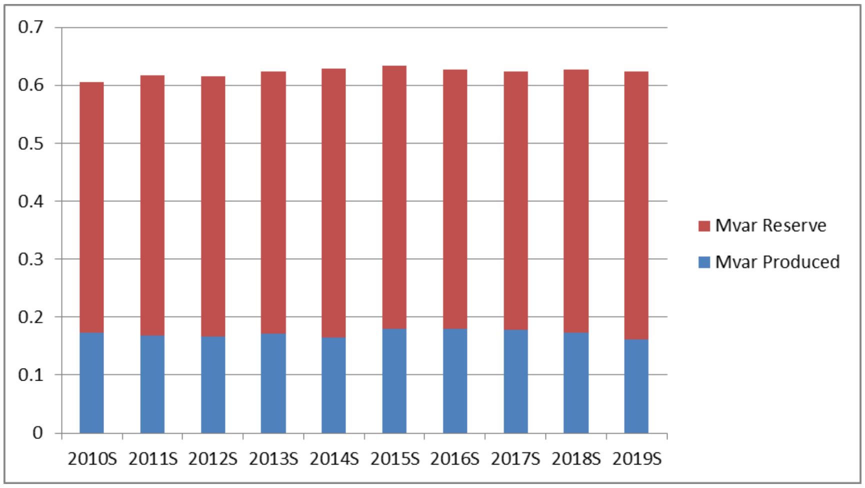


Figure D.67: Southern Company – Planning – Dynamic System (p.u) (Summer Peak)

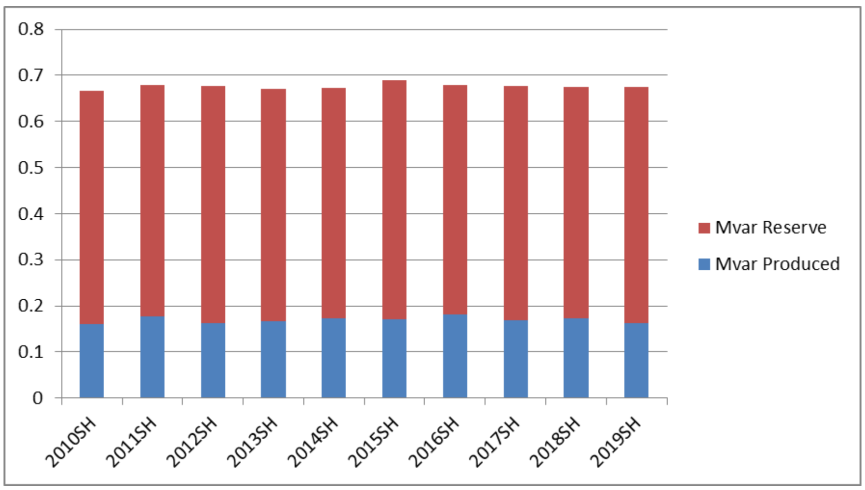


Figure D.68: Southern Company – Planning – Dynamic System (p.u) (Shoulder)

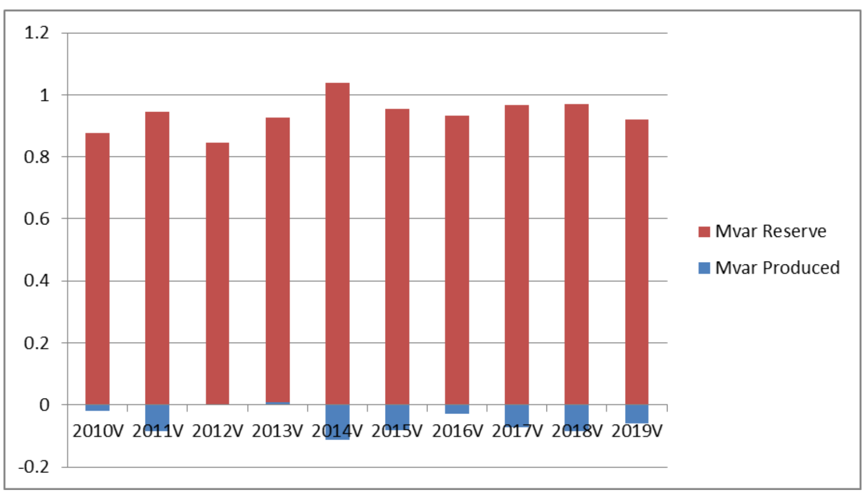


Figure D.69: Southern Company – Planning – Dynamic System (p.u) (Valley

Southern Company – Planning – Static System (P.U.)

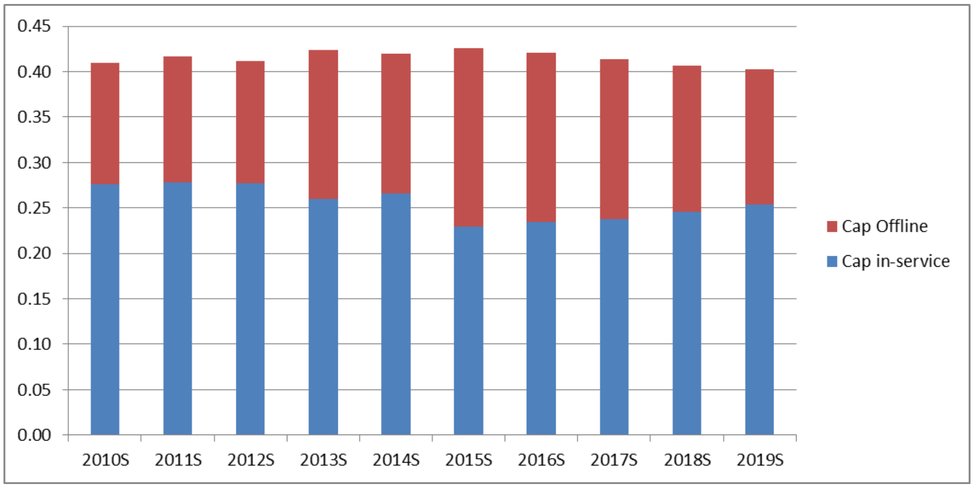


Figure D.70: Southern Company – Planning – Static System (p.u) (Summer Peak)

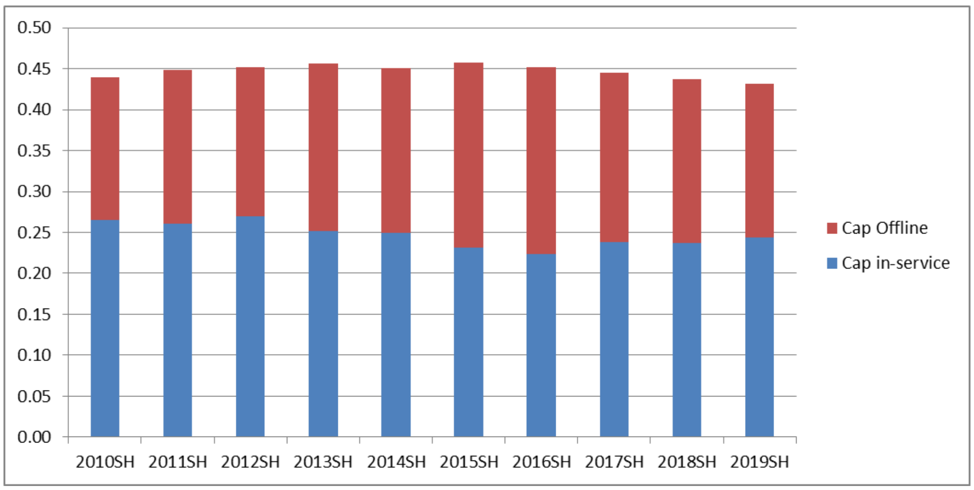


Figure D.71: Southern Company – Planning – Static System (p.u) (Shoulder)

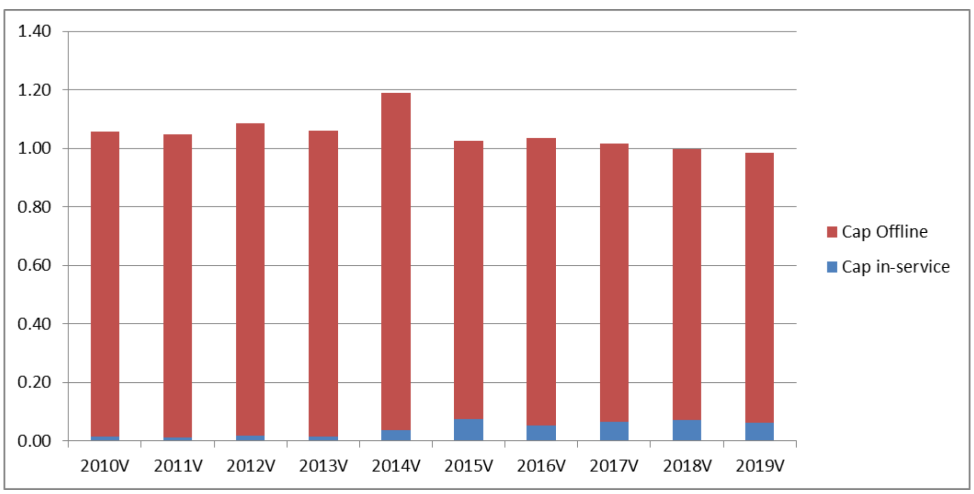


Figure D.72: Southern Company – Planning – Static System (p.u) (Valley)

Southern Company – Planning – Load Trend (MW)

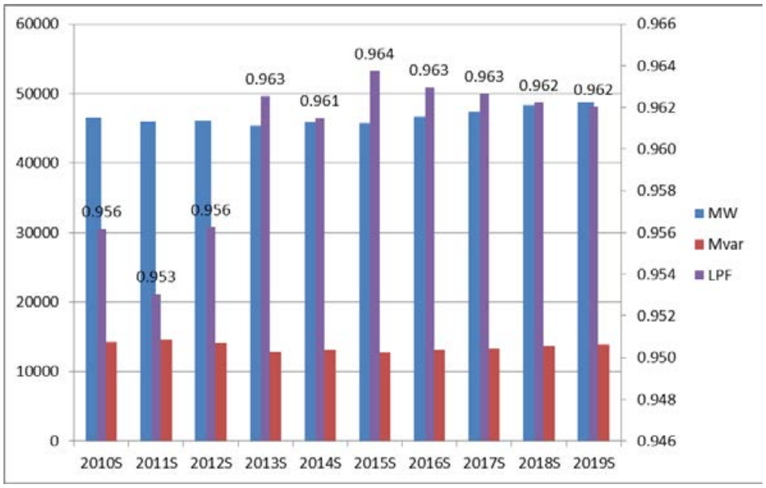


Figure D.73: Southern Company – Planning – Load Trend (MW) (Summer Peak)

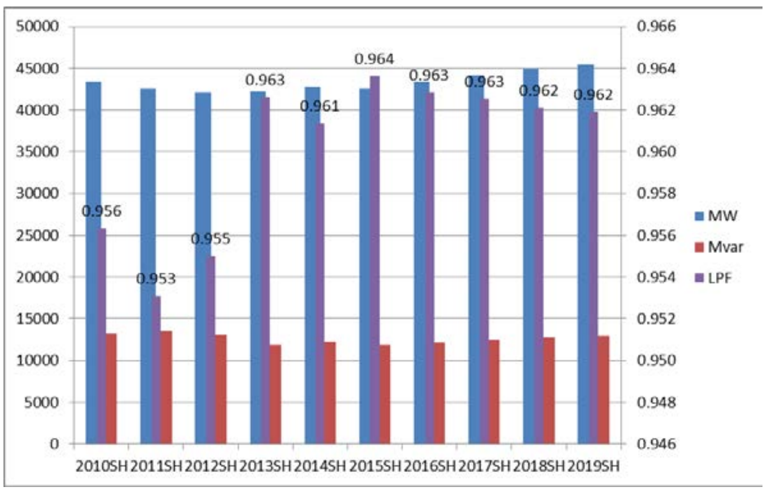


Figure D.74: Southern Company – Planning – Load Trend (MW) (Shoulder)

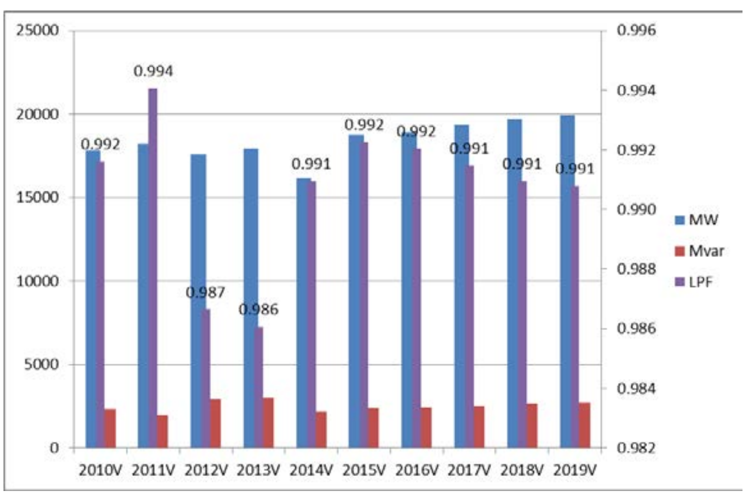


Figure D.75: Southern Company – Planning – Load Trend (MW) (Valley)

Southern Company – Real Time – Dynamic System (p.u.)

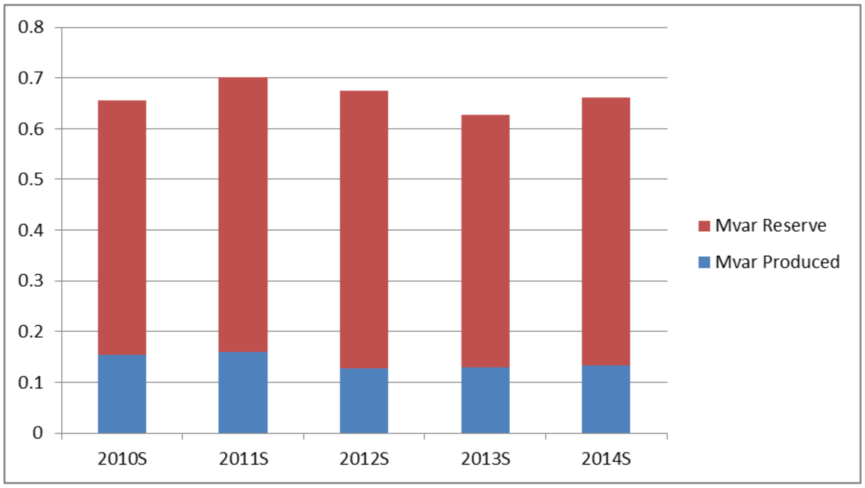


Figure D.76: Southern Company – Planning – Dynamic System (p.u.) (Summer Peak)

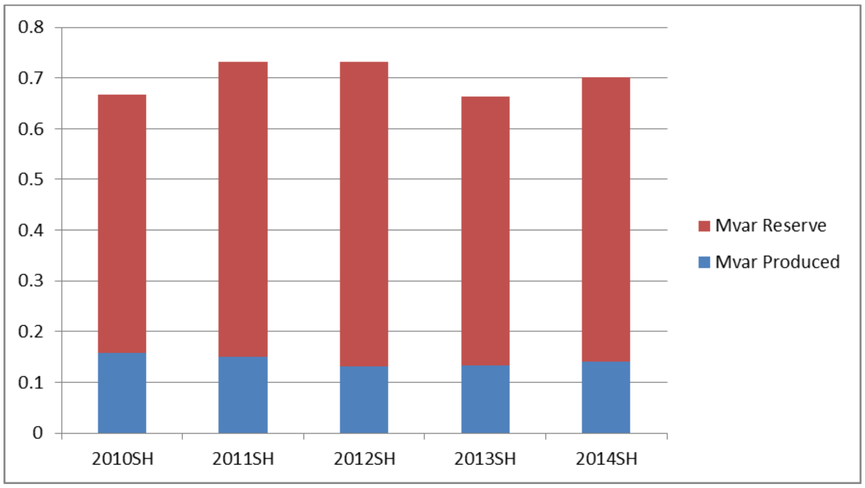


Figure D.77: Southern Company – Planning – Dynamic System (p.u.) (Shoulder)

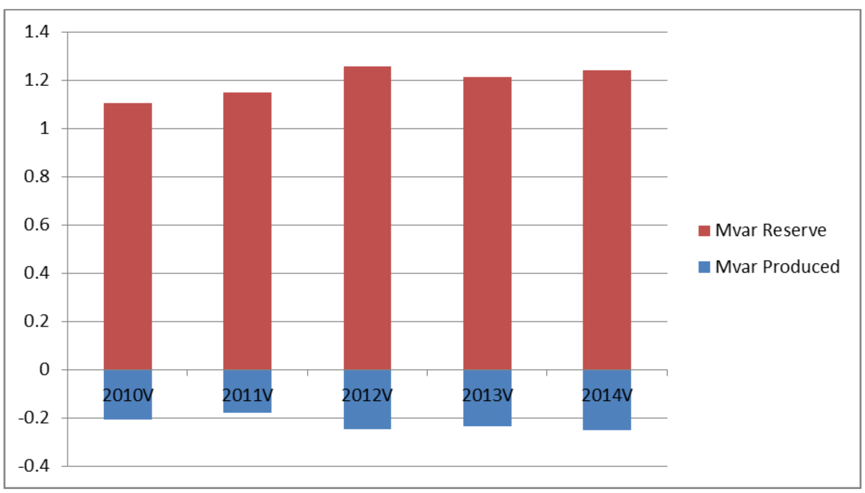


Figure D.78: Southern Company – Planning – Dynamic System (p.u.) (Valley)

Southern Company – Real Time – Static System (p.u..)

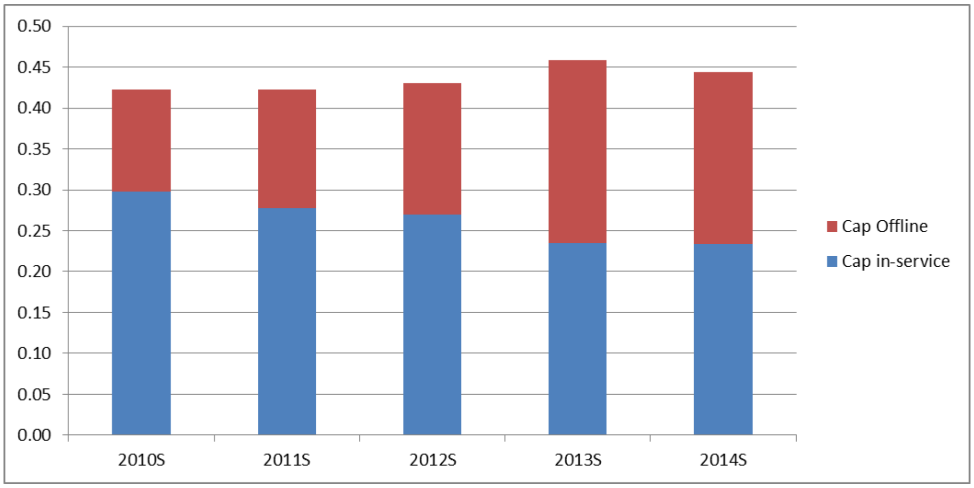


Figure D.79: Southern Company – Planning – Static System (p.u.) (Summer Peak)

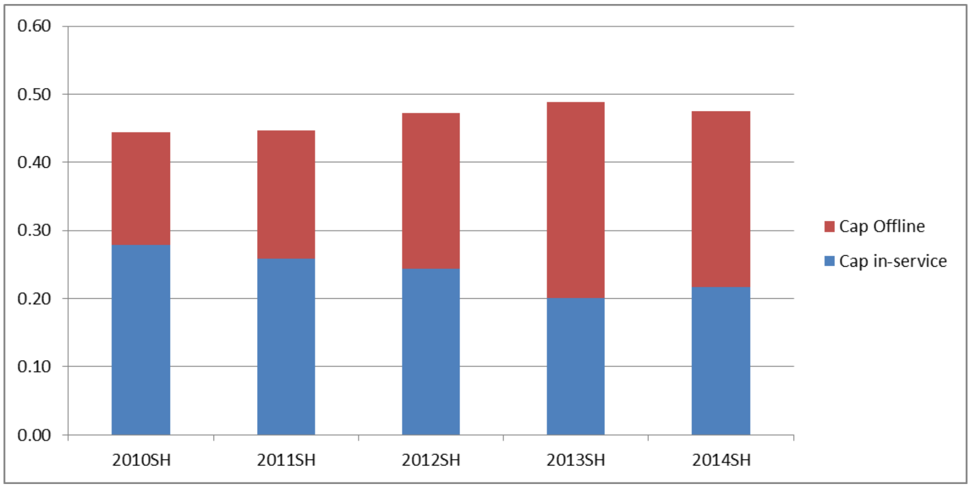


Figure D.80: Southern Company – Planning – Static System (p.u.) (Shoulder)

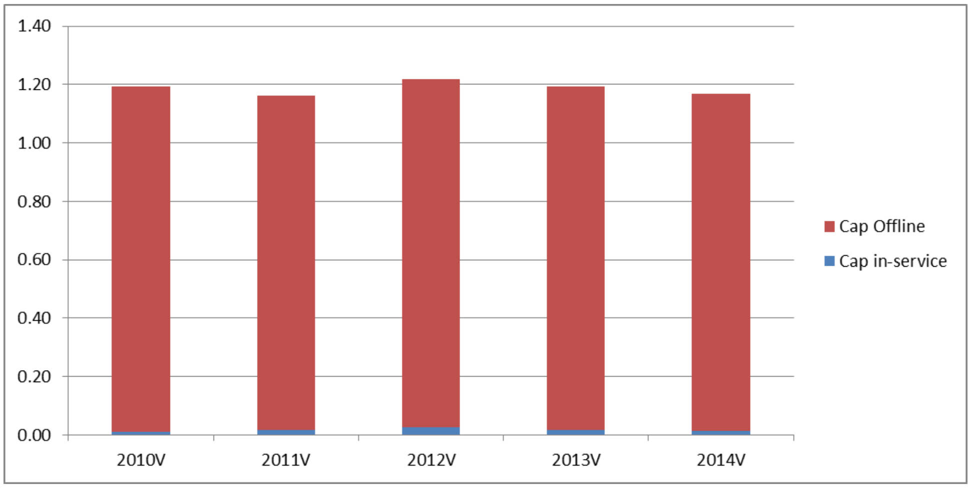


Figure D.81: Southern Company – Planning – Static System (p.u.) (Valley)

Southern Company – Real Time – Load Trend (MW)

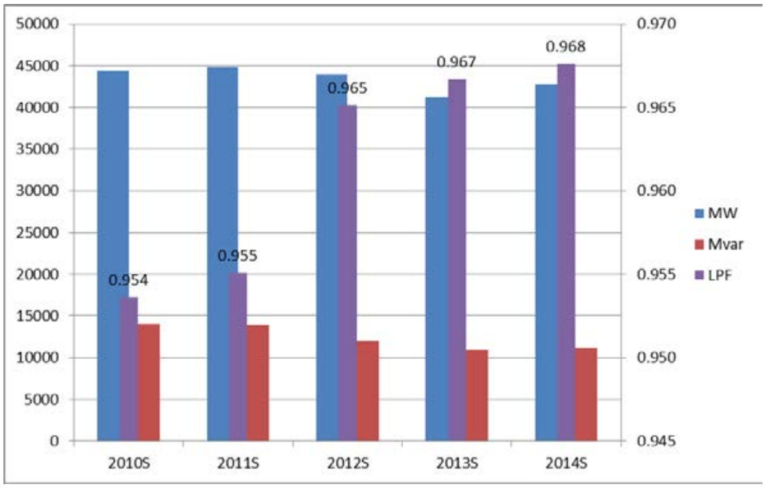


Figure D.82: Southern Company – Planning – Real Time (MW) (Summer Peak)

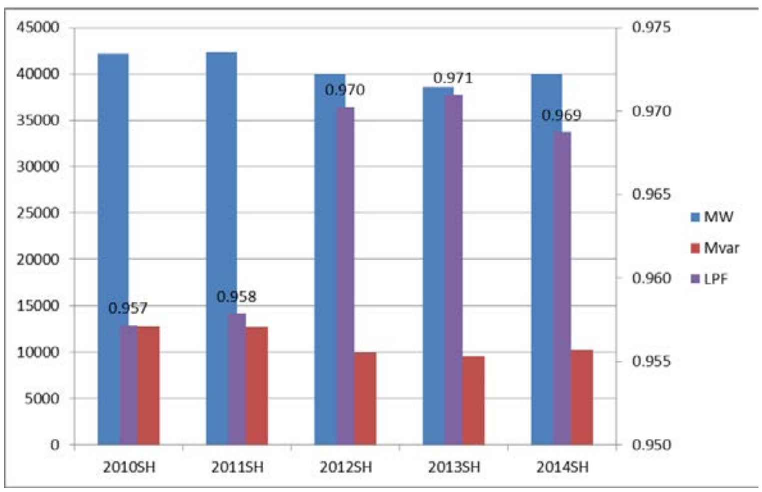


Figure D.83: Southern Company – Planning – Real Time (MW) (Shoulder)

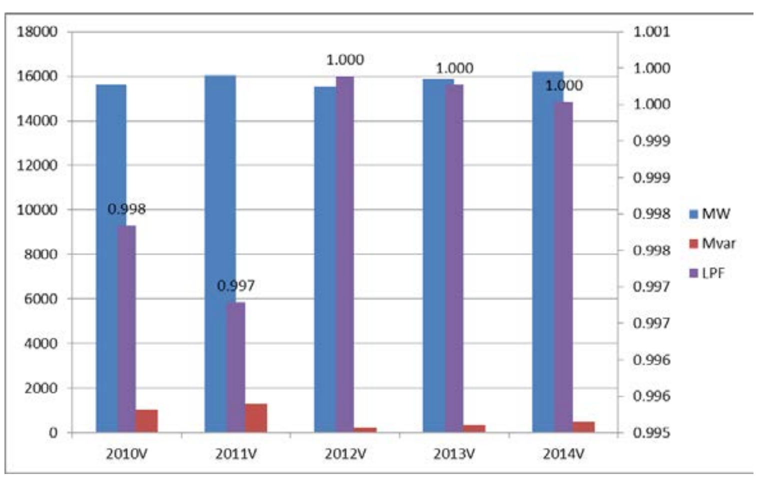


Figure D.84: Southern Company – Planning – Real Time (MW) (Valley)

Appendix E – Short Circuit Ratios for Measure 10 Part Two

Short circuit ratio (SCR) is a metric that has traditionally represented the voltage stiffness of a grid. Conventionally, SCR is defined as the ratio of the short circuit capacity, at the bus where the device is located, to the megawatt rating of the device. Based on this definition, SCR is given by:

$$SCR = \frac{S_{SCMVA}}{P_{RMW}} \qquad (1)$$

where S_{SCMVA} is the short circuit capacity at the bus before the connection of the device and P_{RMW} is the rated megawatt value of the device to be connected.

Equation (1) is the commonly used SCR calculation method when evaluating system strength. The key assumption and limitation of this SCR calculation method is that the studied wind or solar plant does not interact with other such plants in the system. When plants are electrically close to each other, they may interact with each other and oscillate together. In such cases, the SCR calculation using equation 1 can result in an overly optimistic result.

There is currently no industry-standard approach to calculate the proper SCR index for a weak system with high penetration of wind and solar power plants (or other inverter-based resources, such as battery storage). To take into account the effect of interactions between plants and give a better estimate of the system strength, a more appropriate quantity or indicator is needed to assess the potential risk of complex instability. Several approaches, such as GE's Composite Short Circuit Ratio (CSCR) and ERCOT'S Weighted Short Circuit Ratio (WSCR) method, have been proposed to calculate the SCR for a weak system with high penetration of renewable generation.

GE's Composite Short Circuit Ratio (CSCR)

The GE CSCR method is fully described in the following document: *Report to NERC ERSTF for Composite Short Circuit Ratio (CSCR) Estimation Guideline*, GE Energy Consulting: Fernandes, R., Achilles, S., MacDowell, J., January 2015.

ERCOT's Weighted Short Circuit Ratio (WSCR)

The weighted short circuit ratio (WSCR) is defined as:

$$WSCR = \frac{Weighted \quad S_{SCMVA}}{\sum_i^N P_{RMWi}} = \frac{(\sum_i^N S_{SCMVAi} * P_{RMWi}) / \sum_i^N P_{RMWi}}{\sum_i^N P_{RMWi}} = \frac{\sum_i^N S_{SCMVAi} * P_{RMWi}}{(\sum_i^N P_{RMWi})^2} \qquad (2)$$

where S_{SCMVAi} is the short circuit capacity at bus *i* before the connection of nonsynchronous generation plant *i* and P_{RMWi} is the MW rating of nonsynchronous generation plant *i* to be connected. N is the number of wind plants fully interacting with each other and *i* is the wind plant index.

The proposed WSCR calculation method is based on the assumption of full interactions between nonsynchronous generation plants. This is equivalent to assuming that all nonsynchronous generation plants are connected to a virtual point of interconnection (POI). For a real power system, there is usually some electrical distance between each nonsynchronous generation plant's POI, and the nonsynchronous generation plants will not fully interact with each other. The WSCR obtained with this method gives a conservative estimate of the system strength and is considered a proper index to represent the system strength for the studied Panhandle region. A small sample system with four wind plants, as shown in Figure WSCR-1, is used to demonstrate the proposed WSCR concept. The subsystem consisting of four wind plants connects to the main system with weak links. There is no significant electrical distance between each wind plant's POI. Table WSCR-1 shows the wind plant sizes and SCR values calculated using equation 1.

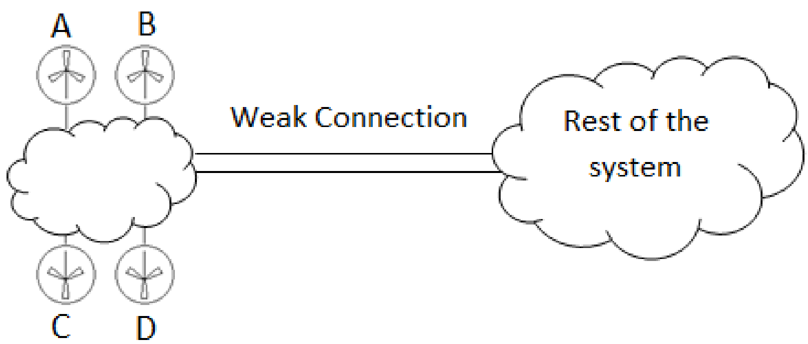


Figure E.1: Four wind generation plants integrated into the system with weak connections

Table E.1: Wind Capacity and SCR Values Assuming No Interaction

Wind plant	Wind Capacity (MW)	Short Circuit Capacity (SCMVA)	SCR
A	1,200	6,500	5.42
B	1,000	8,000	8.00
C	800	8,500	10.63
D	2,000	7,000	3.5

The weighted SCR is calculated using Equation 3.

$$WSCR = \frac{1{,}200*6{,}500 + 1{,}000*8{,}000 + 800*8{,}500 + 2{,}000*7{,}000}{(1{,}200 + 1{,}000 + 800 + 2{,}000)^2} = 1.46 \qquad (3)$$

The calculation in equation 3 shows that even though all the SCR values at each individual POI are larger than 3, the WSCR of the equivalent virtual POI to represent the region is only 1.46. This means the actual system strength is much weaker since the wind plants interact with each other.

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

Appendix F – Task Force Roster & Contributing Entities

Name	Entity
Gerald Beckerle	Ameren
Dave Canter	American Electric Power
Richard Hydzik	Avista Corporation
Clyde Loutan	California Independent System Operator
J. Holeman	Electric Power Research Institute
Robert Entriken	Electric Power Research Institute
Aidan Tuohy	Electric Power Research Institute
Jack Cashin	Electric Power Supply Association
Brendan Kirby	Electric Power System Consulting
Shun-Hsien Huang	Electric Reliability Council of Texas
Julia Matevosyan	Electric Reliability Council of Texas
Alfred Corbett	Federal Energy Regulatory Commission
Hassan Hamdar	Florida Reliability Coordinating Council
Jason McDowell	General Electric
Nicholas Miller	General Electric
Caroline Beaulieu-Cote	Hydro Quebec
David Devereaux	Independent Electricity System Operator
John Simonelli	Independent System Operator of New England
Michael McMullen	MISO Energy
Paul McCurley	National Rural Electric Cooperative Association
Mark Ahlstrom	NextEra Energy
Noha Abdel-Karim	North American Electric Reliability Corporation
Robert Cummings	North American Electric Reliability Corporation
Michelle Marx	North American Electric Reliability Corporation
John Moura	North American Electric Reliability Corporation
Ryan Quint	North American Electric Reliability Corporation
Pooja Shah	North American Electric Reliability Corporation
Ken Schuyler	PJM Interconnection
Dariush Shirmohammadi	California Wind Energy Association
Ronald Carlsen	Southern Company
K. Chakravarthi	Southern Company
Cindy Hotchkiss	Southern Company
Todd Lucas	Southern Company
Thomas Siegrist	Stone, Mattheis, Xenopoulos & Brew, P.C.
Jagan Mandavilli	Texas Reliability Entity
Kenneth McIntyre	The Anfield Group
Brian Evans-Mongeon	Utility Services
Charlie Smith	UVIG
Anthony Jankowski	WE Energies
Steven Ashbaker	Western Electricity Coordinating Council
Layne Brown	Western Electricity Coordinating Council
Donald Davies	Western Electricity Coordinating Council

Exhibit No. IPL-7

Non-Exhaustive List of IPL/AES Stakeholder Presentations

IPL/AES Stakeholder Presentations

Date	Committee	Presentation Title	hyperlink
12/4/2014	SAWG	IPL Harding Street 20 MW BESS	https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2014/20141204/20141204%20SAWG%20Item%2003%20IPL%20Battery%20Project%20Presentation.pdf
1/8/2015	SAWG	RTO Tariff Terms Relative to Energy Storage	https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20150108/20150108%20SAWG%20Item%2004%20IPL%20RTO%20Tariff%20Terms%20Relative%20to%20Energy%20Storage.pdf
2/12/2015	IPTF	Modeling Battery Storage	https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/IPTF/2015/20150212/20150212%20IPTF%20Item%2002%20Battery%20Storage%20Modeling.pdf
3/26/2015	IPTF	IPL Harding Street BESS Project J401	https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/IPTF/2015/20150326/20150326%20IPTF%20Item%2002a%20IPL%20Battery%20Storage%20Modeling.pdf
5/12/2015	RSC	IPL Harding Street BESS Project J401	https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RSC/2015/20150512/20150512%20RSC%20Item%2006%20BESS.pdf
9/15/2015	RSC	Grid Scale Energy Storage and Frequency Response	https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/RSC/2015/20150915/20150915%20RSC%20Item%2003%20AES%20Batteries%20and%20Frequency%20Response.pdf
9/17/2015	MISO SMEs and IMM	Battery Basics	
9/22/2015	TOC	Battery Basics MISO Challenges to J401	Confidential
9/25/2015	MISO RT Operations	Battery Basics	
9/29/2015	MISO Modeling	Battery Basics	Not posted but can supply presentation

	Staff		
10/29/2015	OMS, Consumer Advocates	Lithium Ion Battery Energy Storage	Not posted but can supply presentation
1/8/2016	CUOS	Lithium Ion Battery Energy Storage – Ad Hoc Stakeholder Presentation	Not posted but can supply presentation – distributed broadly
1/11/2016	WOW	Lithium Ion Battery Energy Storage – Ad Hoc Stakeholder Presentation	Not posted but can supply presentation – distributed broadly
1/13/2016	IPP and PM Sector	Lithium Ion Battery Energy Storage – Ad Hoc Stakeholder Presentation	Not posted but can supply presentation – distributed broadly
1/19/2016	TOC	Lithium Ion Battery Energy Storage – Ad Hoc Stakeholder Presentation	Not posted but can supply presentation – distributed broadly
10/10/2016	Xcel Energy	Webinar	Brief on Impending Complaint
10/6/2016	EEI Members	Webinar	Brief on Impending Complaint

Exhibit No. IPL-8

Record of HSS BESS Tours

IPL Advancion Energy Storage Array Tours

Mondav. October 10. 2016
4:38:25 PM

20161021-5095 FERC PDF (Unofficial) 10/21/2016 12:44:39 PM

Date		Start Time	End Time	Company	icipants	Coodinator	Guide	Other
23-May-16	☑	1:00 PM	6:00 PM	Potomac Economics		Lin Franks	Lin Franks	Plant and Solar tour
23-May-16	☑	1:00 PM	3:00 PM	MISO	9	Lin Franks	Lin Franks	Plant tour
12-Jul-16	☑	12:30 PM	4:00 PM	Ribbon Cutting	45	Brandi/Clair	Lin Franks. Et. Al.	
28-Jul-16	☑	3:30 PM	4:30 PM	MISO Leadership	15	Lin Franks	Lin Franks/	
29-Jul-16	☑	10:30 AM	11:30 AM	Regulatory Affairs	15	Ken Flora	Lin Franks	
04-Aug-16	☑	10:30 AM	1:00 PM	Ameren	8	Lin Franks	Franks/Benedict	
10-Aug-16	☑	8:00 AM	5:00 PM	South America	27	Ismario Gonzales	Richard Benedict	
16-Aug-16	☑	11:30 AM	1:30 PM	EPN	35	Richard Benedict	Franks/Benedict	
16-Aug-16	☑	5:30 PM	6:30 PM	MISO Transmission Owners	15	Lin Franks	Lin Franks	
23-Aug-16	☑	5:30 PM	6:30 PM	Lyon Group	7	Ismario Gonzales	Richard Benedict	
24-Aug-16	☑	2:00 PM	3:00 PM	CICP Indiana	3	Greg Fennig	Lin Franks	
31-Aug-16	☑	10:30 AM	12:30 PM	Confidential	3	TJ Winter	Lin Franks	
01-Sep-16	☑	8:00 AM	12:00 PM	RemoteOutage - IPL Energy Storage DCS update		Jeffrey Gibbons	Jeffrey Gibbons	No tours to be scheduled
02-Sep-16	☑	1:00 PM	2:00 PM	MISO	15	Yok Potts	Lin Franks	
06-Sep-16	☑	12:00 PM	5:00 PM	AES Energy Storage	2	Piers Lewis	Piers Lewis	
06-Sep-16	☑	9:00 AM	10:00 AM	E&Y	15	Kurt Tornquist	Lin Franks	Plant Tour
07-Sep-16	☑	1:00 PM	2:00 PM	MISO		Krithika Shenoy	Lin Franks	
07-Sep-16	☑	8:00 AM	5:00 PM	AES Energy Storage	2	Piers Lewis	Piers Lewis	
07-Sep-16	☑	2:00 PM	5:00 PM	Film Crew		Tim Effio	Lin Franks	
08-Sep-16	☑	8:00 AM	12:00 PM	AES Energy Storage		Piers Lewis	Piers Lewis	
08-Sep-16	☑	6:00 AM	9:00 AM	Film Crew		Tim Effio	Lin Franks	
08-Sep-16	☑	9:00 AM	5:00 PM	Film Crew		Tim Effio	Lin Franks	

Date		Start Time	End Time	Company	icipants	Coodinator	Guide	Other
09-Sep-16	☑	2:30 PM	3:30 PM	ACES Power	15	Anita Collier	Lin Franks	
12-Sep-16	☑	10:00 AM	11:00 AM	Duke Energy	2	Jay Rassmussen	Lin Franks	
21-Sep-16	☑	2:00 PM	3:00 PM	Hoosier Energy	9	Richard Benedict	Richard Benedict	
22-Sep-16	☑	11:15 AM	3:00 PM	AES Financial Group	15	Richard Benedict	Richard Benedict	Plant tour
26-Sep-16	☑	10:00 AM	11:00 AM	MISO		Natalie Winters	Lin Franks	
26-Sep-16	☑	12:00 PM	5:00 PM	Battery Off-line		Mark Holbrook		
27-Sep-16	☑	7:00 AM	5:00 PM	Battery Off Line		Mark Holbrook		
29-Sep-16	☑	12:30 PM	4:00 PM	ESN	15	Greg Fenig	Richard Benedict/Others	
01-Oct-16	☐	10:00 AM	11:30 AM	Mexico	5	Malaquias Encarnacion	Richard Benedict	Plant Tour
11-Oct-16	☑	9:00 AM	10:00 AM	MISO-Harmon	9	John Harmon	Lin Franks	
13-Oct-16	☑	8:00 AM	5:00 PM	SCADA; HMI; Upgrade		Charlie Hudelston		No breakers need to open
17-Oct-16	☑	10:30 AM	11:30 AM	IURC	15	Ken Flora	Lin Franks	
18-Oct-16	☑	10:30 AM	12:00 PM	Symphony		Marek Wolek	Richard Benedict	
19-Oct-16	☑	10:00 AM	11:00 PM	WinUp	20	Anita Johnson	Lin Franks	
20-Oct-16	☐	1:00 PM	2:00 PM	Transpower-New Zealand	5	Ismario Gonzales	German Welz	Waitngon conf of time
26-Oct-16	☐	9:00 AM	10:00 AM	Portland General Electric		Kate McGinnis	Richard Benedict	
27-Oct-16	☑	10:00 AM	11:00 AM	Asphalt-Materials	7	Don Hart	Bradley Scott	
28-Oct-16	☑	9:00 AM	10:00 AM	MISO - Jack	15	Carolyn Jack	Lin Franks	Plant tour to follow
08-Nov-16	☑	4:00 PM	5:00 PM	OMS	15	Tanya Paslawski	Lin Franks	
10-Nov-16	☑	1:30 PM	3:30 PM	OMS	15	Tanya Paslawski	Lin Franks	
15-Nov-16	☐			MISO		Kari Bennett	Lin Franks	
30-Nov-16	☑	9:00 AM	10:00 AM	Midwest Govenors Assoc.	5	Lin Franks	Lin Franks	

Date		Start Time	End Time	Company	icipants	Coodinator	Guide	Other
01-Dec-16	☑	10:00 AM	1:00 PM	PS Satefty First	15	Bradley Scott	Bradley Scott	
02-Dec-16	☑	9:00 AM	11:30 PM	MISO - Gardner	19	Lin Franks	Lin Franks	Plant Tour
05-Dec-16	☐			MISO BOD	15	Lin Franks	Lin Franks	
06-Dec-16	☐			OMS	15	Tanya Paslawski	Lin Franks	
48								

Exhibit No. IPL-9

March 10, 2016 Interconnection Process Task Force ("IPTF") Presentation on Frequency Response

MISO

Frequency Response

IPTF
March 10, 2016

Current Requirements

- GIA 9.6.2.1 requires the speed governors (if installed) be operated in automatic mode if they are capable of operation.
- There is no current requirement to provide frequency response
- There is no market mechanism to provide payment for frequency response

Standards and Current Response

- NERC Standard BAL-003 is applicable to the MISO Balancing Authority
- Prescribes a certain amount of frequency response
- Currently meeting our obligations through legacy units and natural load response

FERC Notice of Inquiry

- Commission Notice of Inquiry seeking comments to reform rules around primary frequency response
- Specifically seeks comment on changing pro forma GIA to require all new generation have frequency response capabilities.
- Docket RM16-6

Renewable Energy and IPPs

- New generation interconnections have been changing the MISO fleet toward renewable energy and independent power producers
- With no economic benefit and no requirement, majority of new generation provides no frequency response

MISO Goals

- MISO is noticing a trend of declining frequency response in the MISO BA area.
- MISO desires to change the pro forma GIA language to require frequency response ability, require deadband and droop as set by MISO operations, and give MISO the authority to request governors returned to service

Comments or Suggestions?

- Contact Brett Furuness by March 24th

- **bfuruness@misoenergy.org**
  Use subject line: IPTF FR comment

Exhibit No. IPL-10

May 1, 2011 National Energy Technology Laboratory Report
"Frequency Instability Problems in North American Interconnections"

NATIONAL ENERGY TECHNOLOGY LABORATORY

NETL

Frequency Instability Problems in North American Interconnections

May 1, 2011

DOE/NETL-2011/1473

U.S. DEPARTMENT OF ENERGY

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Frequency Instability Problems in North American Interconnections

DOE/NETL-2011/1473

Final Report

May 1, 2011

NETL Contact:

Maria A. Hanley
Technical Project Monitor

National Energy Technology Laboratory
www.netl.doe.gov

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DOE Contract Number DE-FE0004001

Acknowledgments

This report was prepared by **Energy Sector Planning and Analysis (ESPA)** for the United States Department of Energy (DOE), National Energy Technology Laboratory (NETL). This work was completed under DOE NETL Contract Number DE-FE0004001. This work was performed under ESPA Task 430.01.05.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Maria A. Hanley, NETL Technical Monitor

Steven Bossart, NETL

Joel Theis, NETL

ESPA also wishes to acknowledge the valuable input provided by Greg Gapen and co-workers of **Booz Allen Hamilton, Inc.**, but notes that this acknowledgement does not indicate their endorsement of the results.

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Table of Contents

Exhibits

Acronyms and Abbreviations

AC	Alternating Current
ACE	Area control error
AGC	Automatic generation control
B	Frequency bias constant
BA	Balancing Authority
CC	Combined cycle
CFC	Constant frequency control
CPS	Control Performance Standards
DC	Direct Current
EI	Eastern Interconnection
EIA	Energy Information Agency
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
EPRI	Electric Power Research Institute
f	Frequency
FERC	Federal Energy Regulatory Commission
HVDC	High voltage direct current
Hz	Hertz
ISO	Independent System Operator
LMCP	Locational marginal clearing price
MW	Megawatts electric
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
OASIS	Open Access Same-Time Information System
OFLS	Over Frequency Load Shedding
PJM	PJM Interconnection, LLC
RFC	Reliability *First* Corporation
RMCP	Regulation market clearing price
rpm	rotation per minute
RSG	Reserve Sharing Groups
RTO	Regional Transmission Organization
UFLS	Under-Frequency Load Shedding
WECC	Western Electricity Coordinating Council

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Executive Summary

Alternating current power transmission and distribution systems in the United States operate at a nominal (target) frequency of 60 Hz. Large deviations from this frequency can cause network instability, and even small deviations can adversely affect sensitive end-use devices.

Frequency deviations commonly result from a mismatch between energy supply and demand on a power network. If supply is insufficient to meet demand, the system frequency will decrease; if supply exceeds demand, frequency will increase. Over 100 *balancing authorities* within four electrical interconnections in North America manage power flows so that frequency will remain stable.

Over the past decade, the North American Electric Reliability Corporation (NERC) has observed an increase in frequency stability problems. For example, *frequency response* in the Eastern Interconnection has deteriorated significantly over this period, so that progressively smaller power disturbances are able to induce significant frequency deviations. Several causes of this have been proposed, including changes in:

1. An interconnection's moment of inertia;
2. Load types;
3. Generation control practices;
4. Types of reserves and their availability;
5. Frequency control (monitoring and regulating) practices.

Proposed Cause 1: Interconnection's moment of inertia. The *Moment of inertia,* or rotational inertia, is the rotational analog to mass. Power systems with multiple smaller turbine generators on-line (i.e., a primarily distributed generation system) have less rotational inertia than systems with fewer but larger turbine generators (i.e., a more centralized generation system), giving the more distributed system less kinetic energy immediately available to mitigate frequency changes. Furthermore, as more non-rotating (photovoltaic, fuel cell) and slowly rotating (wind) generators come on line, the kinetic energy per unit of generating capacity available to the overall power system to stabilize frequency decreases.

Proposed Cause 2: Load types. Some end-use devices, such as electric motors, contribute to frequency stability because they use more power at higher frequencies and less power at lower frequencies, thereby helping demand adjust to meet supply. As the load in North America changes, with less industrial consumption and more commercial and residential consumption, it includes more electronics and variable-speed drives that do not demonstrate the same beneficial frequency-power relationship as inductive motors.

Proposed Cause 3: Generation control practices. Deregulation and competition in the generation industry have provided operators with incentives to operate plants at peak local efficiency (versus what is optimal for the overall power system) resulting in changes in *generation control practices*. Unfortunately, some operating practices can result in a lowering of the available range of governor control of on-line generators. This reduces the available level of *primary frequency control*, the ability of the system to react within a few seconds to stabilize system frequency.

Proposed Cause 4: Types of reserves and their availability. Deregulation and competition also have provided control area operators with incentives to keep *generation reserves* at a minimum. To reduce costs, some operators have organized into reserve sharing groups (RSGs) that collectively meet their reserve requirements. Since the RSGs and generators can choose the market into which to sell services, lower levels of reserves may be available to respond to frequency disturbances.

Proposed Cause 5: Frequency control practices. Frequency control regimes include primary, secondary, and tertiary means. Primary control reacts in seconds to stabilize the system frequency, usually at a level different from nominal. It is implemented through governor control, assisted automatically by the system's moment of inertia and frequency-dependent load response. Secondary control is used over a few minutes to bring frequency back to the nominal range. It primarily consists of automatic generation control (AGC) to control multiple generators and reduce area control error (ACE) to within acceptable limits. Tertiary controls bring available generators on-line over a period of minutes to hours to re-stabilize the frequency at the nominal level, freeing up AGC to respond to future disturbances.

The generator units are bidding power and price in the ancillary services market, but they do not bid technical characteristics. The ancillary market is cleared such that minimum cost service is provided, but this does not ensure that the power supplied for ancillary services has the optimal technical characteristics. Consequently, selecting providers of ancillary services in this manner does not necessarily ensure that the system will respond to disturbances as desired

While the technical implementation of frequency control is directly responsible for an interconnection's frequency stability, the standards and regulations have both direct and indirect effects on the ability to implement the technical control. For example, the implementation of Federal Energy Regulatory Commission (FERC) Orders 888 and 889 has had significant indirect effects on frequency control, through the opening of electricity markets to competition and the re-allocation of responsibilities for system reliability. Specifically, the FERC Orders established market conditions that deeply influenced the investment decisions with respect to new generation projects changing the mix of the generation portfolio. Also, in Order 888, FERC made transmission providers, rather than generators, responsible for the delivery of frequency regulation and response.

Some unintended effects resulted in greater incentives for private investment in smaller, more distributed generation, which tends to provide fewer frequency stability benefits than larger plants. The higher reliability of smaller distributed units is not counterbalanced by the possible detrimental effects on grid frequency stability. The ideal system component for effecting primary control is a (or a limited number of) large baseload unit(s) with a considerable moment of inertia in order to absorb and arrest the perturbation to the overall power system. Such a need is best served by coal-fired power plants, since other operational constraints keep nuclear plants from accepting primary governor control

As part of the first set of mandatory reliability standards approved by FERC Order No. 693 in 2007, NERC issued resource- and demand-balancing standards that directly impact frequency stability. As originally issued, the regulations were missing key recommended NERC guidelines with respect to generator governor control for primary frequency response. In its Order 693, FERC directed NERC to modify the standards to determine the appropriate periodicity of surveys necessary to ensure reliability standards were being met, and to define the frequency response required for reliable operation, along with the methods of obtaining and measuring that the frequency response is achieved.

In March 2010, FERC issued an Order setting a deadline for compliance to Order 693. Subsequently, technical conferences have been held to address concerns by NERC and the various Regional Transmission Organizations with respect to the Order. In the absence of a clear and well-defined frequency response reliability standard, regional entities, reliability councils, and balancing authorities have developed local standards to try to maintain 60 Hz frequency, keep system stability, and provide reliable supply.

The most concerning issue with frequency stability is the observed decline in the primary frequency response and its effect on frequency stability. Until 2007, qualified facilities smaller than 80 MW were not required to provide spinning reserve for primary control at all. FERC, NERC, and the Independent System Operators (ISOs) have recognized this limit as too high, and currently all power plants larger than 10 MW are required to participate in primary control. This change does not seem to be sufficient to address lack of primary control, and NERC standardization committees are working on a new set of requirements which will define in much better terms how the primary frequency response should function to improve frequency response characteristics.

1 Introduction

For a stable and reliable electrical power system, several operational parameters must be maintained within tolerance levels. Both generation and demand depend on these parameters for their own stable and reliable operations. The most important parameters are system frequency and voltage. Frequency is a system-wide characteristic while voltage is a local feature. This report focuses on frequency stability issues in the United States.

This report correlates the increased number of larger and longer-lasting frequency excursions with electricity market design and frequency control regulations. In order to make the connection between direct (technical) causes and indirect (non-technical) causes, both the physics of the problem and the regulatory environment (i.e., regulations, standards, and policies) must be understood first. The purely physical dimension of the issue can be broken down into the physical laws governing the frequency stability phenomenon and system control efforts responsible for maintaining the nominal system frequency. Similarly, the indirect effects of the regulatory environment can be broken down into the impact of policy on market design which in turn affects frequency stability and the regulations directly affecting frequency control practices. The report concludes with recommendations, covering both technical and policy aspects of the issue, to improve frequency stability in the NERC-regulated territory.

Alternating current power transmission and distribution systems, generation, and demand equipment in the United States are designed to operate at the nominal frequency of 60 Hz. Tight adherence to this target permits multiple generators to provide stable power to a single network. Large deviations from this frequency can cause network instability, and even small deviations can adversely affect sensitive end-use devices. The definition of what is a large and what is a small deviation depends on the system topology and the generation and demand conditions. Frequency deviations result from a mismatch between power supply and demand on a power network. If supply is insufficient to meet demand, the system frequency will decrease; if supply exceeds demand, frequency will increase. Over 100 Balancing Authorities nationwide are responsible for managing power flow between regions so that frequency will remain stable. [1] Although almost all of the generators are synchronous generators set to generate 60 Hz electricity, the system frequency is rarely exactly 60 Hz. Small power mismatches cause small frequency deviations, which are expected and easily handled. Large frequency deviations can be a problem leading to equipment damage and even blackouts. Large frequency deviations are usually caused by sudden loss of generation but can also be caused by sudden, unexpected changes in demand. Frequency deviations of less than 0.05 Hz are usually considered small although these could be significant depending on the interconnection and even operating conditions. The IEEE recommends that frequencies within +/-0.036 Hz around the nominal frequency be considered as nominal.[2] Frequencies lower than 59.3 Hz automatically trigger the

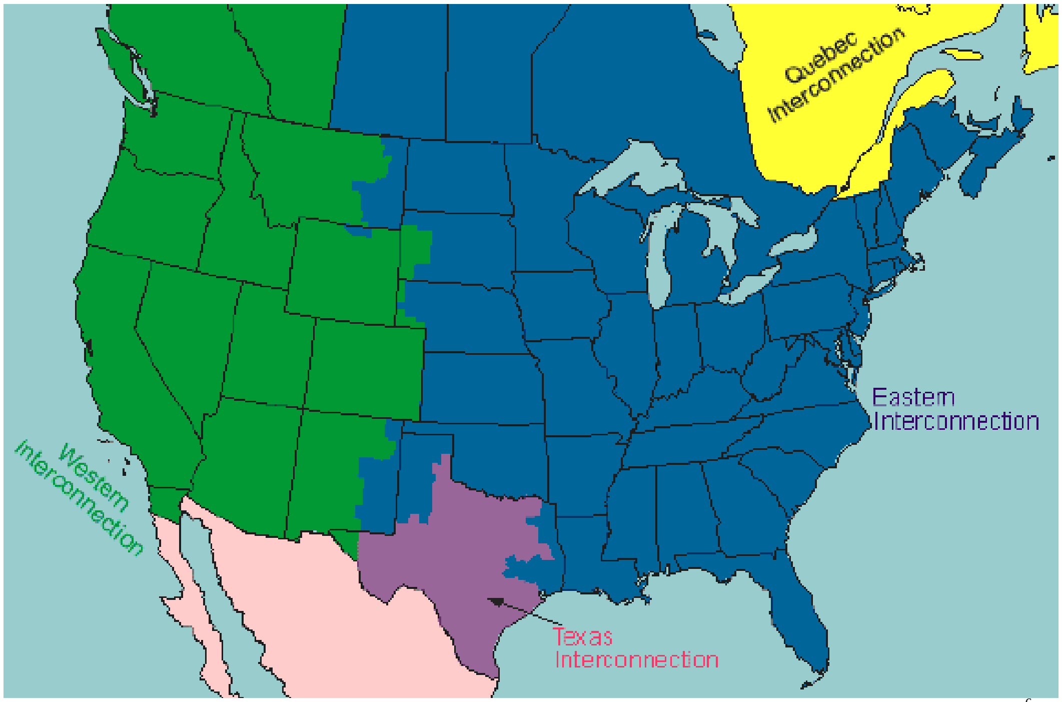
[1] North American Electric Reliability Corporation (NERC) Resources Subcommittee, *Balancing and Frequency Control (Part I)*, Washington, D.C., 2009.

[2] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

first level of under-frequency load shedding (UFLS). [3,4] If the frequency drops below 57 Hz or rises above 61.8 Hz, during some time period, manufacturers could recommend that generators should be disconnected to prevent generator damage. These limits are not fixed and they depend on generator type and previous generator condition.[5]

The entire North American electrical power system is partitioned into four interconnections that maintain their own frequency as close to 60 Hz as possible. The partitioning and different interconnection frequencies are achieved by using high voltage direct current (HVDC) lines and back-to-back HVDC links. HVDC lines have AC/DC and DC/AC converters at both ends of the line allowing for different frequencies. The four North American interconnections, shown in Exhibit 1-1:

Exhibit 1-1 North American Interconnections



Source: NERC 2009 [6]

[3] UFLS is usually done in three levels. For example, ERCOT UFLS provides 5 percent system load relief if frequency drops below 59.3 Hz, an additional 10 percent if frequency drops below 58.9 Hz, and an additional 10 percent if frequency drops below 58.5 Hz. In total, ERCOT UFLS provides 25 percent load relief. Source: ERCOT, *ERCOT Nodal Operating Guide – Section 2: System Operations and Control Requirements*, December 2009, p. 2-15.

[4] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

[5] IEEE Power Engineering Society, *ANSI/IEEE C37.106 – IEEE Guide for Abnormal Frequency Protection for Power Generating Plants*, New York, New York, 2004.

[6] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I)*, Washington, D.C., 2009.

- The Eastern Interconnection (EI) (covering Central Canada eastward to the Atlantic coast (excluding Québec), and south to Florida
- Electric Reliability Council of Texas (ERCOT) which encompasses most of Texas
- The Western Electricity Coordinating Council (WECC), west of Kansas to the Pacific coast, stretching from Western Canada, south to Baja California in Mexico
- The Quebec Interconnection, which is linked to and considered a part of the EI.

Although power is exchanged between these four interconnections, the frequency in each interconnection can be controlled independently due to the HVDC links among them. In recent years, the North American Electric Reliability Corporation (NERC) has observed an increase in frequency stability problems in all four interconnections.

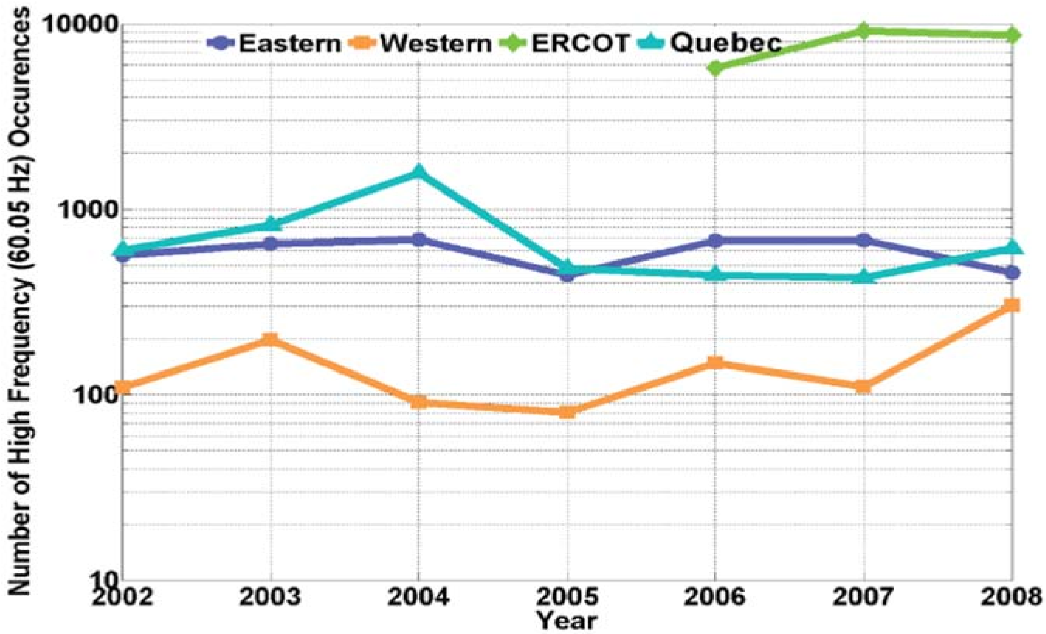
For example, based on historic data,

Exhibit 0-1 and Exhibit 1-3 illustrate the number of high (> 60.05 Hz) and low (< 59.95 Hz) frequency (*f*) events between 2002 and 2008. In the EI, during 2002, there were about 250 low-frequency events per year while in 2007 there were more than 1,000 low-frequency events per year. In 2006, NERC was granted the role of the Electric Reliability Organization (ERO) to monitor and enforce the reliability standards.[7] In 2007, NERC's voluntary reliability standards and recommendations became enforceable reliability standards[8] and the number of low-frequency events declined to about 850 per year. This number is still 240 percent higher than it was in 2002. The cause of the change in frequency behavior is not clear. Direct, technical causes can be traced, but the indirect causes are more elusive.

[7] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062 (ERO Certification Order), *order on reh'g & compliance*, 117 FERC ¶ 61,126 (July 20, 2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

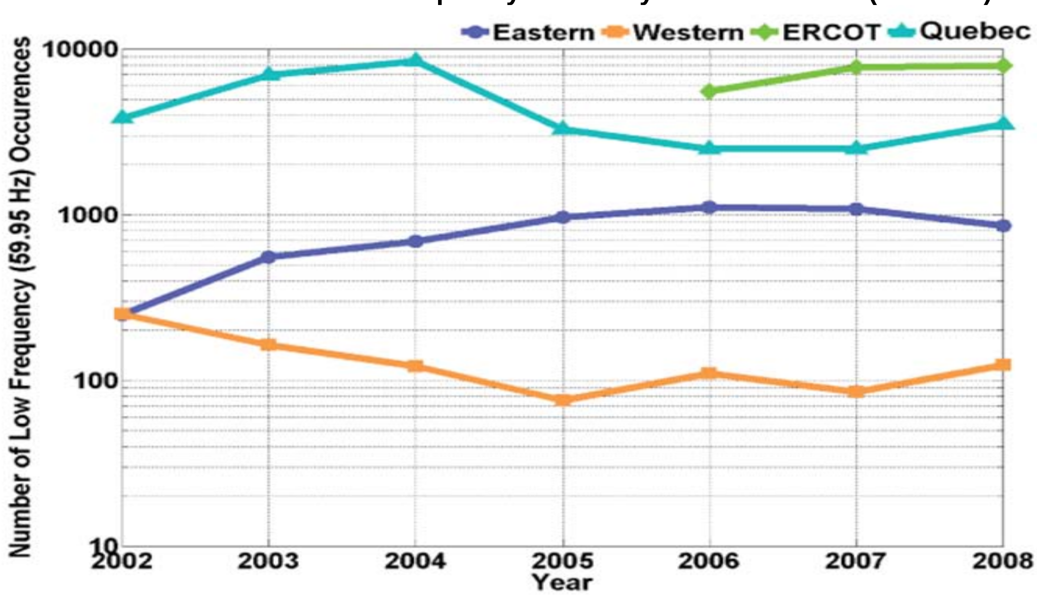
[8] *Mandatory Reliability Standards for the Bulk Power System*, Order No. 693, 72 FR 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), order on reh'g, 120 FERC ¶ 61,053 (2007) (Order No. 693-A) [hereinafter Order No. 693] "approves 83 of 107 proposed Reliability Standards, six of the eight proposed regional differences, and the Glossary of Terms Used in Reliability Standards developed by the North American Electric Reliability Corporation (NERC)."

Exhibit 0-1 Number of High-Frequency Events by Interconnection (*f* > 60.05 Hz)



Source: NERC - *Frequency Excursions (High)* [9]

Exhibit 0-2 Number of Low-Frequency Events by Interconnection (*f* < 59.95)



[9] NERC, "*Frequency Excursions (High*)", available at http://www.nerc.com/page.php?cid=4|37|257|270|271 (accessed on September 12, 2010).

Source: NERC - *Frequency Excursions (Low)* [10]

This report correlates the increased number of larger and longer-lasting frequency excursions with electricity market design and frequency control regulations. In order to make the connection between direct (technical) causes and indirect (non-technical) causes, both the physics of the problem and the regulatory environment (i.e., regulations, standards, and policies) must be understood first. The purely physical dimension of the issue can be broken down into the physical laws governing the frequency stability phenomenon (covered in Section 2.1 below) and system control efforts responsible for maintaining the nominal system frequency (covered in Section 2.2 below). Similarly, the indirect effects of the regulatory environment can be broken down into the impact of policy on market design which in turn affects frequency stability (covered Section 3.1 below) and the regulations directly affecting frequency control practices (covered in Section 3.2 below). The report concludes with recommendations, covering both technical and policy aspects of the issue, to improve frequency stability in the NERC-regulated territory.

[10] NERC, "*Frequency Excursions (Low),*" available at http://www.nerc.com/page.php?cid=4|37|257|270|271 (accessed on September 12, 2010).

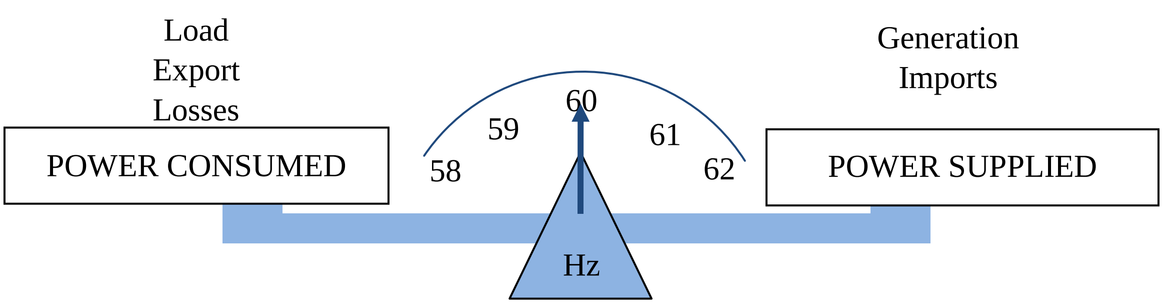
2 Technical Aspects of the Frequency Stability Issue

2.1 Physics of Power Balancing and Frequency Stability

Electrical power demand and power supply must be continuously balanced. If the demand and supply are not balanced, or if there is not enough stored energy[11] in the system to temporarily supply the imbalance, generation and demand equipment can be damaged and the entire system could collapse. A power imbalance occurs as a result of a mismatch between generation and load. While there are minor mismatches that exist on the grid most of the time, significant imbalances in either magnitude or time span can be catastrophic for a power system (e.g., result in system black outs and/or equipment damage).

Almost all alternating current (AC) power is generated by synchronous generators controlled to produce 60 Hz electricity. When generated power exactly matches power demand, the frequency could be either a nominal 60 Hz or in its vicinity, but it would be stable (Exhibit 2-1). Unless an imbalance between generation and demand is quickly mitigated, frequency could decrease to 0 Hz in a case of demand exceeding generation or increase until equipment is damaged in a case of generation exceeding demand. Even a very small, but long-lasting power mismatch can cause a significant decrease in frequency.

Exhibit 2-1 Power Balance



Data Source: EPRI [12]

The four interconnections, discussed in the Introduction, are connected using high voltage direct current (HVDC) links. The HVDC links allow each interconnection to have a different frequency, while the frequency inside an interconnection is the same for any point in that system. For example, the frequency in Los Angeles, CA, can be different from the frequency in Bangor, ME, yet the Bangor frequency is the same as the frequency in Miami, FL. This also means that imbalances in Bangor should not affect Los Angeles frequency but could potentially affect frequency in Miami, since they are in the same interconnection. All four interconnections try to

[11] Either passive storage, such as a battery, or kinetic energy within the power system could offset the power imbalance.

[12] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

maintain their frequencies within a narrow band around 60 Hz[13] specific to their own operating standards. For example, the normal frequency is between 59.95 Hz and 60.05 Hz for the Eastern Interconnection, and between 59.856 Hz and 60.144 Hz for the Western Interconnection.[14]

A mismatch between generation and demand is the direct cause for frequency instability. There are five main system characteristics and operational practices that influence the severity of, and recovery from, power mismatches:

1. An interconnection's moment of inertia;
2. Load types;
3. Generation control practices;
4. Types of reserves and their availability;
5. Frequency control (monitoring and regulating) practices.

An interconnection's moment of inertia does not cause power imbalances, but it does affect the system's inherent response to those disturbances and the frequency control methodology used to recover from those disturbances. Some load types are frequency-dependent and since most of such loads are inductive in nature, they actually act as natural frequency stabilizers. Generation control practices are closely related to generation efficiency and as such have a direct effect on the profit margins; this could be a serious issue in deregulated market environments. Spinning and non-spinning reserves are critical during primary and secondary frequency control (defined and described in detail below); reserve operations can also be affected by market design. Monitoring and data collection enable control of frequency during real-time operations and also form the basis of intelligent, data-driven formulation of standards and regulations.

2.1.1 Power System Moment of Inertia

A system's moment of inertia is the total moment of inertia of the connected power generating units, including both the prime mover and the generator of each unit. The moment of inertia is defined as the product of rotating mass and the square of the distance from the center of rotation. A rotating mass has characteristics of an energy storage device. Rotational speed of synchronous generators, which is the same for all interconnected generators, is actually the system frequency. During acceleration, energy is stored, and during deceleration, it is released. In the case of a negative frequency deviation, during acceleration, the system's moment of inertia works against frequency control efforts because it is storing rotational energy; during deceleration the moment

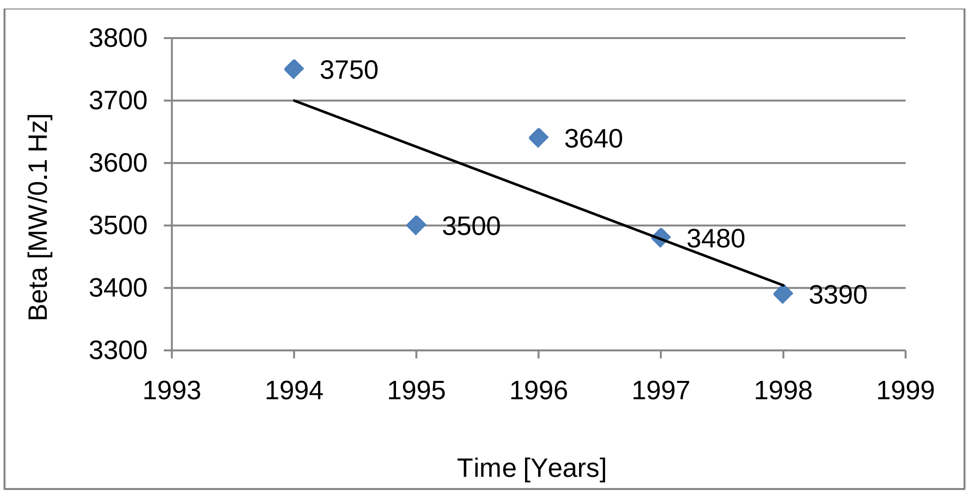
[13] 60 Hz is the nominal frequency for the United States. The nominal frequency can be offset by ± 0.02 Hz (scheduled frequency is equal 59.98 Hz or 60.02 Hz) during Time Error Correction. The NERC Glossary defines "time error correction" as "an offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value." Further, the NERC Glossary defines the "time error" as "the difference between Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology."

[14] NERC, "Leading Indicators: *Frequency Excursions,*" available at http://www.nerc.com/page.php?cid=4|37|257|270 (accessed September 12, 2010).

of inertia helps to control frequency by releasing previously stored rotational energy. It is important to remember that it is not the moment of inertia that affects the frequency response but the energy stored. For example, a two-pole generator that must rotate at 3600 rpm to produce 60 Hz has four times the stored energy (i.e., kinetic energy contained within the system) of a generator with four poles rotating at 1800 rpm also producing a nominal 60 Hz and having the same moment of inertia. Wind power plants are usually described as having negligible moment of inertia, which is not necessarily true, but they do have negligible stored energy due to their slow rotational speed.

Along with the magnitude of a power imbalance, the moment of inertia at synchronous speed is a major variable that defines the initial frequency deviation. The lower the moment of inertia is, the larger the deviation produced, and the higher the moment of inertia is, the smaller the deviation. Over the last 10 to 20 years, the electric power generation industry has experienced a significant shift from large, centralized power plants with significant moment of inertia to small, more distributed, and renewable power plants with much less moment of inertia. Over the same time period, the frequency response characteristic, measured as the imbalance per 0.1 Hz frequency deviation (β), of the Eastern Interconnection has decreased as shown in Exhibit 2-2. A decreasing frequency response means that progressively smaller power disturbances cause the same frequency excursion of 0.1 Hz.

Exhibit 2-2 Decline in β in Eastern Interconnection Over 5-Year Period



Data Source: Ingleson & Nagle, 1999 [15]

If the β trend in the Eastern Interconnection shown in Exhibit 2-2 is extrapolated to the year 2010, it would be around 2500MW/0.1Hz. This means that a loss of a large 1300 MW generator would cause a frequency deviation of about 0.05Hz. This frequency degradation is not a cause for serious concern yet, but if the trend continues or gets worse there could be some unpleasant consequences in the not so distant future.

[15] Ingleson, J., and Nagle, M., *Decline of Eastern Interconnection Frequency Response*, Fault and Disturbance Conference, Atlanta, GA,1999.

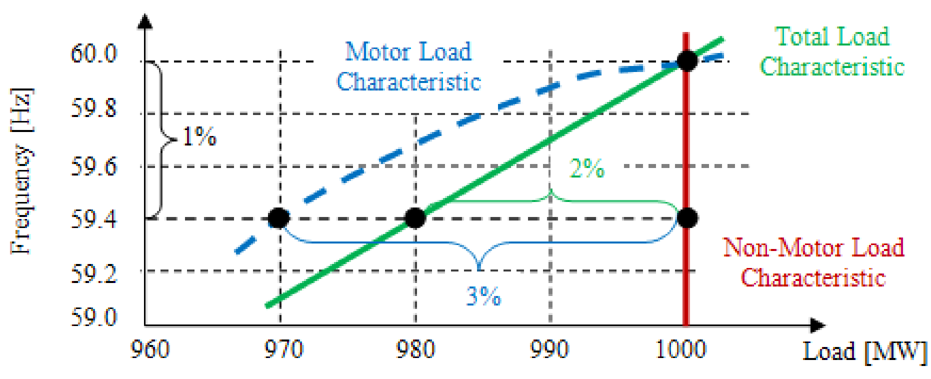
2.1.2 Load Types

Since system demand fluctuates continuously, an interconnection rarely operates at exactly targeted or scheduled frequency of 60 Hz. The ability of a system element, such as generator or load, to react or respond to the inherent fluctuations in system frequency is known as the "element frequency response." There are two types of element responses, controlled and uncontrolled. Generators respond in a control manner due to the application of some control logic. On the other hand, loads with energy storage elements are frequency dependent, having well-defined but uncontrolled elemental frequency response.

In general, loads can be grouped into three major categories: industrial, residential, and commercial. Each load category has its own characteristics. For example, industrial loads tend to be heavy rotating machines with high inertia and good frequency responses. On the opposite side of the load spectrum are commercial and residential loads, which usually include electronically controlled devices with a weaker frequency response. The effect of load type on the frequency response is important to the extent that it has been suggested as a separate input to the frequency response models.[16] Inductive loads, such as rotational electrical machines, are natural frequency stabilizers.

Exhibit 2-3 illustrates three load types: motor load (blue dotted line), total load (green line), and non-motor load (red line). Motor loads (blue dotted line) increase during frequency excursions, which helps stabilize system frequency. However, non-motor loads (red line) are unchanged by frequency fluctuations and, consequently, do not contribute to buffering the system frequency. The total load characteristic frequency response (green line) is the superposition of the various load types frequency response. Therefore, systems with higher motor load content have more muted responses to frequency deviations and therefore have more inherent stability than systems with lower motor load content.

Exhibit 2-3 Motor Load and Frequency Dependence



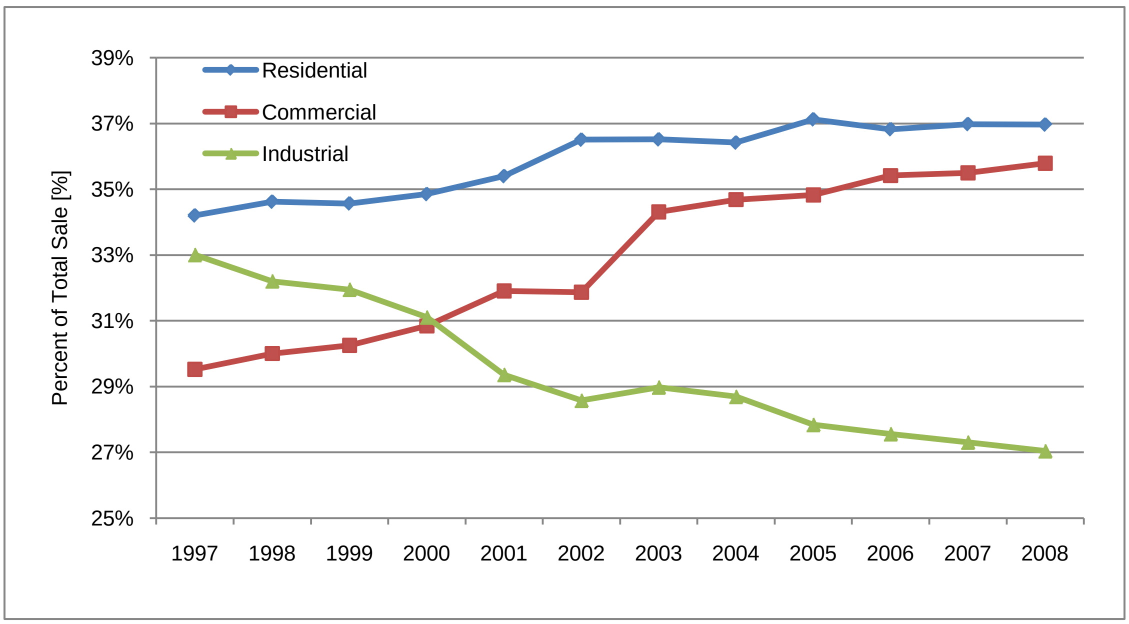
Source: Electric Power Research Institute, 2009, p. 4-8, used with permission [17]

[16] Mitchell, M.A. Lopes, J.A.P., Fidalgo, J.N. and McCalley, J.D., *Using a Neural Network to Predict the Dynamic Frequency Response of a Power System to an Under Frequency Load Shedding Scenario*, IEEE PES Summer Meeting, Seattle, WA, 2000, p. 346-351.

[17] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

The following factors not only affect the magnitude of the load but also the load type affecting the frequency response. In recent years, industrialized countries' load distribution has changed from mostly rotating machine loads to low- and high- power electronics. Relative reductions in rotating machine loads might be a contributor to larger frequency excursions experienced recently by the Eastern Interconnection operators. Loads using AC/DC conversion as well as purely resistive loads are not frequency dependent. Exhibit 2-4 shows the percent of energy sales by load type between 1997 and 2008. Loads are also affected by other drivers, including population, economic situation and growth, temporal behavior patterns, and weather patterns. A change in any of these factors could change load compositions. It might be noted that nearly all of the above factors have recently changed dramatically, from the population to the weather patterns. The US population has increased almost linearly with time (Exhibit 2-5 below) which, in general, shifts load composition away from industrial toward residential and commercial loads while the weather is an inherently dynamic phenomenon.

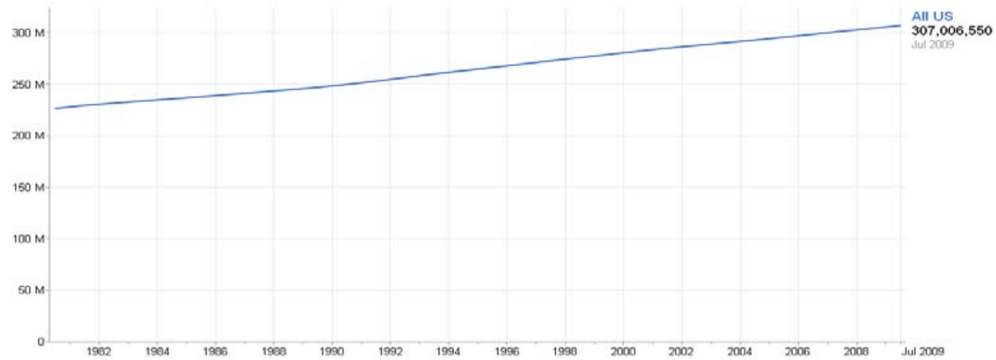
Exhibit 2-4 U.S. Retail Sales of Electricity to Ultimate Customers by Sector



Source: EIA- Electricity [18]

[18] Energy Information Agency (EIA), *Electricity - Table 7.2. Retail Sales and Direct Use of Electricity to Ultimate Customers by Sector, by Provider, 1997 through 2008* http://www.eia.doe.gov/cneaf/electricity/epa/epat7p2.html (accessed on September 12, 2010).

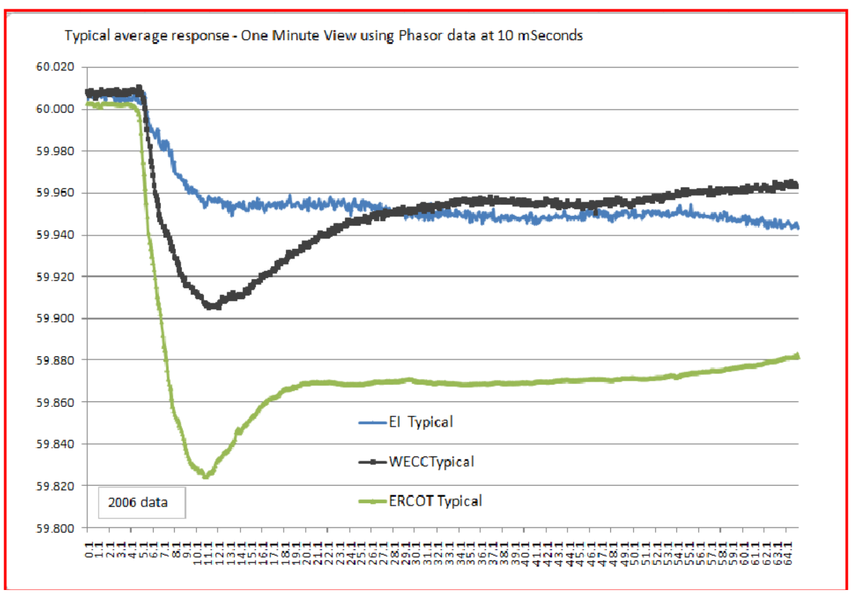
Exhibit 2-5 Near-Linear Population Growth in US



Data Source: US Census Bureau [19]

Frequency response characteristics can be different in interconnections with different type loads. Exhibit 2-6 shows typical frequency response in the Eastern Interconnection, Western Electricity Coordinating Council, and Electric Reliability Council of Texas. The frequency response in the Eastern Interconnection is distinctly different from the frequency responses in WECC and ERCOT. One factor is that the Eastern Interconnection load traditionally consists of more rotating industrial machines than the other interconnections and consequently has better frequency response characteristics. [20]

Exhibit 2-6 Typical Frequency Traces Following a Unit Trip



Source: NERC 2009 [21]

[19] US Census Bureau, Population Division, Washington, D.C., 2009.

[20] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[21] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I),* Washington, D.C., 2009.

2.1.3 Generator Operations and Control Practices

Generators have little to no reason to consider stability of the interconnections frequency when optimizing the operations. Neither the Federal Energy Regulatory Commission (FERC) nor NERC mandates generators to take part in primary frequency control (i.e., actions taken to stabilize frequency in the event of a significant deviation, described in detail in Section 2.2.1 below). Generators larger than 10 MW are expected to participate in primary frequency (governor) control by adjusting their real power output. NERC recommends that each generator larger than 10 MW have a governor control with five percent droop characteristic. As discussed below, on March 18, 2010, FERC issued an Order[22] to NERC to submit a modified BAL-003 reliability standard within six months and to define the necessary amount of frequency response needed for reliable operation. At this time, primary frequency control is only required by some balancing authorities such as ISO New England.

However, as was mentioned in the PJM Interconnection, LLC (PJM) request for clarification and rehearing of the FERC March 18, 2010 Order, this has never been a requirement.[23] For efficiency and financial reasons, generators can choose control schemes that are not the most responsive to frequency deviations but are more financially beneficial to their owners. For example, a generator operator can choose to operate at full capacity leaving no operating margin for the governor control. Operating a unit at full capacity will generate larger profits because the owner would be able to sell more energy at market prices. Since no ancillary services market currently exists for primary frequency control, there is only the ancillary market for frequency regulation;[24] thus, the generator owners do not have strong incentives to participate in frequency response to the best of their ability. Deregulation, the competitive nature of energy markets, and the lack of a primary frequency control standard have driven a large number of generator units to operate at maximum output levels, so they are optimized based on an individual generating unit's financial perspective. Therefore, there is no assurance that generator units will be available for frequency response when they are needed.[25] Certain generator operations are cited as possible contributors to the primary frequency response declines due to control reasons[26,27] such as the following:

[22] *Order Setting Deadline for Compliance*, 130 FERC ¶ 61,218 at P 1 (March 18, 2010).

[23] *Order Setting Deadline for Compliance,* Request of PJM Interconnection, L.L.C. for Clarification and Rehearing of the Order Setting Deadline for Compliance, Docket No. RM06-16-010 (April 19, 2010), p. 2, PJM states: "Lastly, the Commission states at Paragraph 16 that '[t]he need to keep some level of frequency response existed in prior NERC policies and procedures.' However, there has never been a requirement that the industry provide for governor response and the Commission's statement to the contrary is inaccurate."

[24] Primary frequency control is not the same as frequency regulation.

[25] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[26] *Order Setting Deadline for Compliance*, Request of the North American Electric Reliability Corporation for Clarification and Rehearing of the Order Setting Deadline for Compliance, Docket No. RM06-16-010, p. 9 (April 19, 2010).

[27] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

- Steam turbine sliding pressure control and/or "valves wide open" operation
- Combined cycle (CC) exhaust temperature control
- CC positive frequency feedback
- Nuclear power plant-blocked governor control

Steam power plants can work in two different operating modes: constant pressure and sliding pressure mode. In the constant pressure mode, boiler pressure is kept constant regardless of generator output (load). In sliding pressure mode, boiler pressure is a linear function of generator output where maximum pressure is achieved for maximum generator output. If the steam power plant is used as a continuous base-load unit, it is able to achieve high efficiency in a constant pressure mode. However, non-base-load units need to be able to adapt their operations to variations in the power that they are scheduled to inject into the system. Consequently, steam turbine generators that are not base load (a.k.a., partial-load plants) need to seek other operating regimes to improve their efficiency.

Operating a plant in a "sliding pressure" mode is a possible solution that increases steam power plant efficiency during partial-load operation. In this mode, the boiler provides only the required pressure to meet demand without any throttling. The disadvantage of the "sliding pressure" mode is the reduced ability to meet short-term demand fluctuation, because fast-responding valves are used as protection for sudden steam pressure increases.[28] The steam power plants that work in "sliding pressure" mode cannot be used for frequency response. In the U.S. there is at least one power plant that works in this mode. It is the Mountain View power plant in California.[29]

Combined cycle (CC) exhaust temperature control regulates the fuel such that a temperature increase/decrease is controlled and the CC unit operates at maximum capacity ratings.[30] In this control mode, a CC unit cannot respond in the upward direction. If the CC unit does not operate at maximum capacity, it can provide some frequency/system disturbance response until the exhaust temperature reaches its upper limit.

CC units can have a positive frequency feedback. This means that when the frequency drops, the CC output will drop as well.[31] Exhibit 2-7 illustrates a CC unit response to frequency change. The blue line represents frequency and the red line is the generator's MW output. The CC unit shown has a positive frequency feedback and will reduce output power by 1.05 MW, which is a 2.5 percent reduction in machine output. This type of frequency response may cause problems, because the generator unit would make the situation worse during an emergency event. This type

[28] Flynn, D., *Thermal Power Plant Simulation and Control,* London, Institution of Electrical Engineers, 2000.

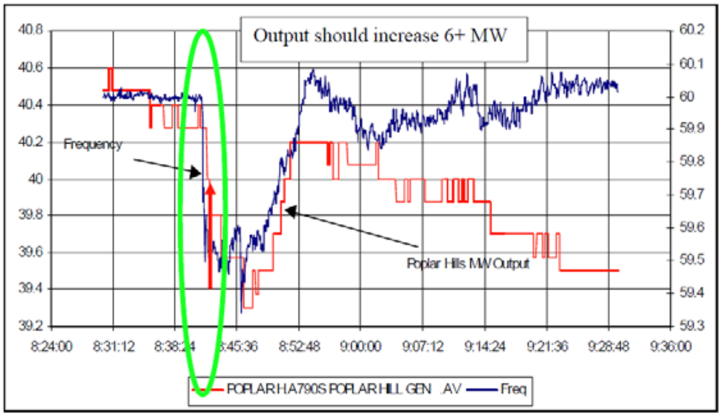
[29] http://tdworld.com/underground_transmission_distribution/SCE-underground-circuits/ (accessed on September 1, 2010).

[30] Grigsby, L, *Power system stability and control,* Boca Raton: CRC Press, 2007.

[31] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper,* Princeton, New Jersey, 2004.

of frequency response can be modified, but plant operators need to be educated about such events and be motivated to respond in a more holistic manner.

Exhibit 2-7 Combined Cycle Response to Frequency Change



Source: NERC 2004[32]

Nuclear power plants are capable of governor response but they are usually operated at maximum capacity rating and cannot respond to frequency deviation or be used for primary frequency control.[33] The steady state nuclear plant power output provides safety benefits for nuclear power plant operations.

2.1.4 Types and Availability of Generation Reserves

The minimum operating reserve differs from region to region; it is usually based on the largest generating unit on-line or the single most severe contingency.[34] For example, the Western Electricity Coordinating Council requires contingency reserves equal to the greater of

- The most severe contingency
- Three percent of load plus three percent of net generation[35]
- Five percent of the load supplied by hydro power plants plus seven percent of the load supplied by thermal generation[36,37]

[32] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[33] Flynn, D, *Thermal Power Plant Simulation and Control.* London, Institution of Electrical Engineers, 2000.

[34] Reliability standard BAL-002-0 states that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency" (effective April 1, 2005).

[35] Reliability standard BAL-002-WECC-1, Requirement R.1.1, (Effective on the first day of the next quarter, after receipt of applicable regulatory approval), available at (http://www.nerc.com/files/BAL-002-WECC-1_Final.pdf (accessed on September 15, 2010).

The Electric Reliability Council of Texas requires 1,354 MW for contingency reserve and at least 2,300 MW for responsive reserve.[38]

The PJM requires the minimum contingency reserve must be sufficient to cover the largest contingency. [39] However, different regional reliability organizations that comprise PJM have additional requirements. For example, the minimum contingency reserve in Reliability *First* Corporation (RFC) should be 150 percent of the largest unit in RFC, or 1,700 MW for the Mid-Atlantic zone. In addition, spinning reserve should be at least fifty percent of contingency reserve, and interruptible load should not be more than twenty-five percent of contingency reserve.[40]

In a vertically regulated industry, the balancing authority (BA) is responsible to provide full reserve for its individual largest contingency and some for multiple contingencies.[41] In a regulated environment, the BA operator most likely owns the generator and knows the technical characteristics of typical units. This knowledge helps the control area operator to select the generation portfolio that would best respond to power imbalance as desired.[42] This is not the case in a deregulated environment.

In the current deregulated environment, control area operators are motivated to reduce operating costs. Consequently, reserve sharing groups (RSG) have been established within a NERC region. An RSG collectively supplies operating reserve[43] such that each BA proportionally contributes to covering the largest RSG contingency, thus reducing overall amount of reserves required to cover the largest contingency and the associated costs for all members of the RSG. Because belonging to an RSG is voluntary, generators can still choose the market in which to sell their services (i.e., energy market, ancillary service market, or both).

Exhibit 2-8 provides an example of hourly regulation services (regulation market clearing price [RMCP] and energy prices (locational marginal clearing price [LMCP]) for the PJM market. The regulation prices are typically, but not always, lower than energy prices. These generator units are bidding power and price in the ancillary services market, but they do not bid technical characteristics. The ancillary market is cleared such that minimum cost service is provided, but

[36] Reliability standard BAL-STD-002-0, Requirement a.(ii), (will be effective when approved by the Federal Energy Regulatory Commission under Section 215 of the Federal Power Act), available at http://www.nerc.com/files/BAL-STD-002-0.pdf (accessed September 15, 2010).

[37] Hrist, E., and Kirby, B., *Technical and Merket Issues for Operating Reserves*, Tennessee: Oak Ridge, 1998.

[38] ERCOT, *Operating Procedure Manual – Frequency Control Deck*, available at http://www.ercot.com/mktrules/guides/procedures/ (on line accessed on 9/15/2010).

[39] PJM, *Manual 12 - Balancing Operations (Attachment D)*, effective October 5, 2009, p. 78.

[40] PJM, *Manual 13 – Emergency Operation (Section 2)*, effective August 13, 2010, p. 11.

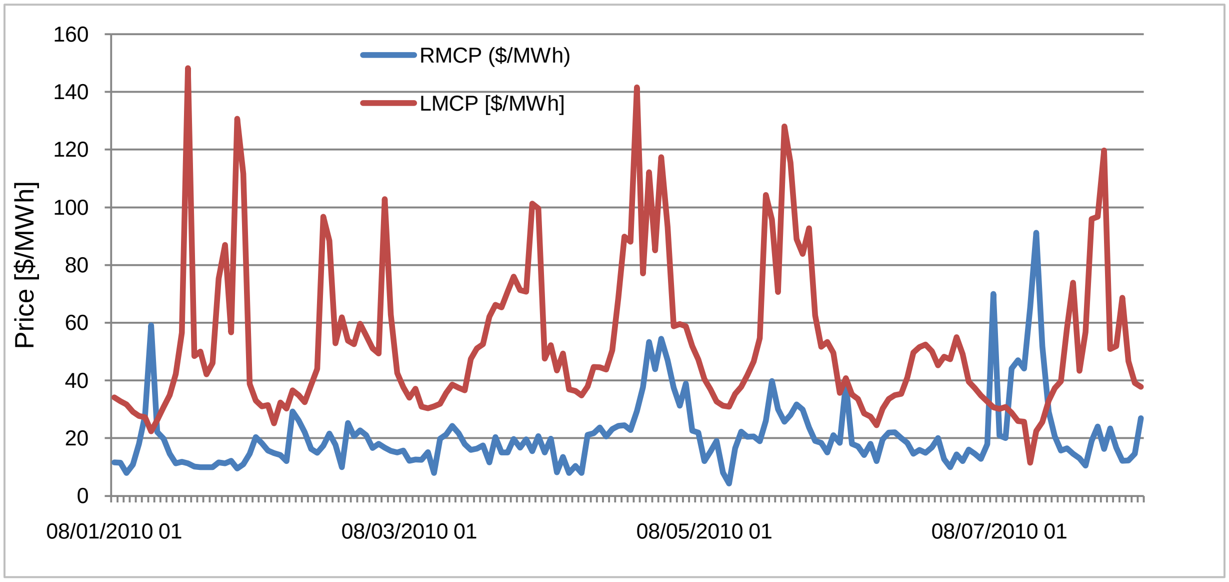
[41] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[42] Hrist, E., and Kirby, B., *Technical and Market Issues for Operating Reserves*, Tennessee: Oak Ridge, 1998.

[43] NERC, *NERC Operating Manual*, New Jersey, 2004.

this does not ensure that the power supplied for ancillary services has the optimal technical characteristics. Consequently, selecting providers of ancillary services in this manner does not necessarily ensure that the system will respond to disturbances as desired. The RSG and generator preference to choose the market where they will provide service leads to less reserve available to respond to frequency disturbances, and to a decline in primary frequency response.[44]

Exhibit 2-8 Hourly Regulation and Energy Prices in PJM



Data Source: PJM [45]

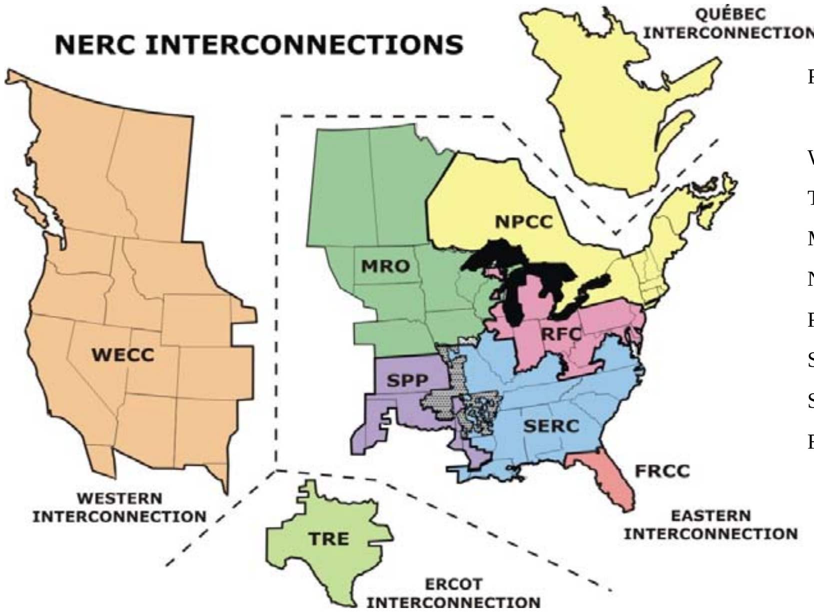
2.1.5 Frequency Control (Monitoring and Regulating) Practices

Frequency monitoring and regulation are crucial to frequency control. Grid interconnections must conform to the criteria set forth by NERC. Within each interconnection, there are a number of Reliability Coordinators. Each Reliability Coordinator coordinates operations of a number of BAs running automatic generation control (AGC) within their balancing authority areas. Exhibit 2-9 shows the North American Interconnections with Reliability Coordinators in each Interconnection.

[44] Frequency Task Force of the NERC Resources Subcommittee, *Frequency Response Standard Whitepaper*, Princeton, New Jersey, 2004.

[45] http://www.pjm.com/markets-and-operations/energy/real-time/lmp.aspx (accessed on September 11, 2010) and http://www.pjm.com/markets-and-operations/ancillary-services/mkt-based-regulation.aspx (accessed on September 11, 2010).

Exhibit 2-9 NERC Interconnections and Regions



Regional entities

WECC – Western Electricity Coordinating Council
TRE – Texas Regional Entity
MRO – Midwest Reliability Organization
NPCC – Northeast Power Coordinating Council
RFC – Reliability *First* Corporation
SPP – Southwest Power Pool
SERC – SERC Reliability Corporation
FRCC – Florida Reliability Coordinating Council

Source: NERC website[46]

Each BA is connected to its neighboring areas and contributes to the frequency regulation of the entire interconnection by continuously balancing its internal demand and generation to meet scheduled interchanges. The BA, therefore, continuously participates in the overall frequency regulation of the entire interconnection. The BAs are connected to each other through "tie lines," which monitor the energy flow out as positive and the energy flow in as negative. The difference between the actual interchange and the scheduled interchange is called "inadvertent interchange" and is supplied or absorbed by the interconnection system. The term "inadvertent" emphasizes the expected function of the control area, which is to match the actual interchange to the scheduled. However, this task is often not possible, and therefore, in reality the BA maintains the inadvertent interchange within the limits set by NERC in the Control Performance Criteria.

The BAs contribute to stabilizing the frequency of the interconnection system through their primary control and automatic generation control, both of which are described in detail in Section 2.2. As long as the balance between actual and scheduled interchange is maintained, the area control error (ACE) of a BA is zero. A non-zero ACE value causes a frequency excursion that might affect operations of the entire interconnection during the primary frequency response.

The BAs must adhere to NERC guidelines and standards to ensure they will not burden other balancing areas during normal operations. In addition to NERC, other local or federal regulatory

[46] NERC Interconnections (Color), available at http://www.nerc.com/fileUploads/File/AboutNERC/maps/NERC_Interconnections_color.jpg (accessed on September 11, 2010).

entities might impose their own guidelines and requirements on the operation of the control areas. NERC also provides guidelines for the inadvertent interchange management.

The control performance standards/guidelines are provided by NERC, but there has been considerable discussion in the literature on their efficiency. The current standards are focused on calculating the ACE, as defined by the following equation:[47]

$$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME} \qquad (1)$$

Where:

NI_A = Net Interchange, Actual

NI_S = Net Interchange, Scheduled

B = Balancing Authority Bias

F_A = Frequency, Actual

F_S = Frequency, Scheduled

I_{ME} = Interchange (tie line) Metering Error

A more extensive discussion of ACE follows in Section 2.2.2 below.

The above discussion reveals the need for the following:

- Analysis of data from many control areas and reserves with different load profiles to determine optimal control functionalities that could be associated with specific time windows
- Development of statistic-based correlations to identify effective parameters for use in the control performance standards
- Collection of time and location based frequency response data for the above
- Smart methods for collecting statistically meaningful data with sufficient resolution to achieve the above
- Assessment of various periods with different load and generation ramp-rates
- Sensitivity analysis to determine critical metrics for optimal economics and performance
- Validation of the above metrics based on real-world data

2.2 Frequency Control

The purpose of all control systems is to maintain the output of a controlled system at a pre-specified or time-changing value. A control algorithm might have to satisfy certain constraints and objectives. In the case of frequency control, the objective is to maintain the nominal frequency as closely as possible. If there is a disturbance, it is desirable to restore the nominal

[47] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I),* Washington, D.C., 2009.

frequency quickly. Frequency deviations are an indication of power mismatch in the power network. If power generation and demand are not balanced, the frequency continues to increase if generation exceeds demand (or decrease if demand exceeds generation). Eventually connected equipment starts failing and after some time the power system collapses (e.g., power is not delivered at the quality and quantity demanded). For this reason, quick frequency restoration is mandatory.

Frequency control is implemented in stages where each stage acts over a different time scale. At the first stage, called primary or governor control, frequency change is stopped. At the next stage, secondary or automatic generation control restores the frequency to its nominal value using designated AGC generators. Generation is re-dispatched to relieve AGC generators for future control actions at the tertiary stage. Exhibit 2-10 summarizes the frequency control stages along with their timeframes and NERC standards regulating them.

Exhibit 2-10 Control Continuum Summary[48]

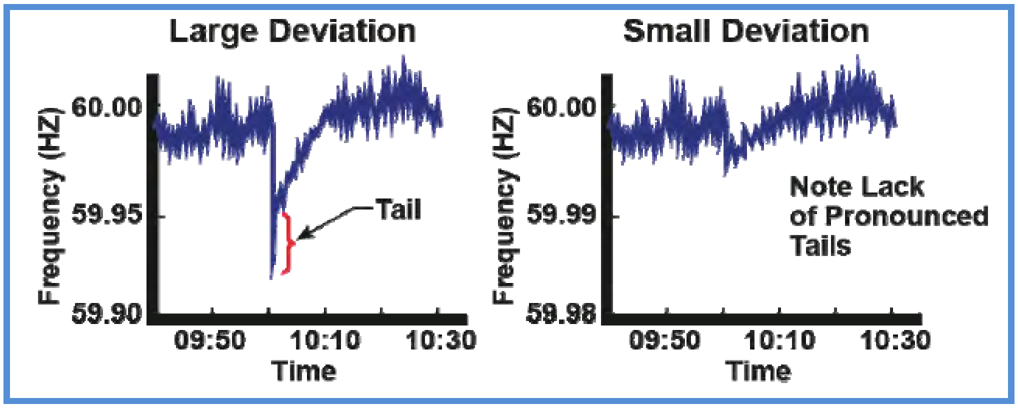
Control	Ancillary Service	Timeframe	NERC Standard
Primary Control	Frequency Response	10-60 seconds	FRS-CPS1[a]
Secondary Control	Regulation	1-10 Minutes	CPS1-CPS2
Tertiary Control	Imbalance/Reserves	10 Minutes – Hours	BAAL-DCS
Time Control	Time Error Correction	Hours	TEC

[a]*CPS=Control Performance Standard*

Since demand is the aggregation of a very large number of small loads that turn on and off randomly, frequency continuously fluctuates around some average value. In its statistical nature, this type of fluctuation is small when observed on a short time scale. It is not possible to compensate for small, very fast frequency deviations. The IEEE recommends that frequencies within +/-0.036 Hz around the nominal frequency be considered as nominal.[49] Exhibit 2-11 illustrates typical small- and large-frequency deviations.

[48] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I)*, Washington, D.C., 2009.
[49] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

Exhibit 2-11 Frequency Profile after Large and Small Deviation



Source: Electric Power Research Institute, 2009, p. 4-28, used with permission [50]

The interconnections discussed in the Introduction are partitioned into areas handled by balancing authorities. From scheduled intertie flows, real-time intertie flow measurements, and system frequency, it is straightforward to determine which area is responsible for power imbalance as well as the ACE. Initially, after an imbalance occurs, the entire system participates in frequency regulation, but the area responsible for the imbalance is expected to eventually account for its internal imbalance. Once an imbalance is detected, the system responds at different time scales. Primary control responds within seconds, secondary control within minutes, tertiary control within minutes to hours, and time control within hours.

2.2.1 Primary Frequency Control

The primary control starts within seconds of a disturbance occurrence to prevent further frequency deterioration; the primary control's role is not to return the frequency to its nominal value, but to stabilize it. The primary control is implemented through governor control helped by the system's moment of inertia and frequency-dependent load response. Governor control adjusts the prime mover's power input, which is directly related to the generated electrical power. Governor control is normally activated by a frequency drop below 59.97 Hz or a rise above 60.03 Hz. A governor responds to frequency deviations according to its droop curve. The droop curve determines the generator's power output based on the frequency measurement. A typical droop curve is shown in Exhibit 2-12.

In North America, the industry practice is 5 percent droop.[51] This means that a generator should go from zero to full capacity if the frequency changes by 5 percent (or 3Hz). A 5 percent frequency change, or 3 Hz, corresponds to +/- 1.5 Hz around 60 Hz. Exhibit 2-13 shows a governor response for a 0.1 Hz disturbance. In this case, the frequency will stay at its new operating point of 60.1 Hz unless the AGC reacts as well.

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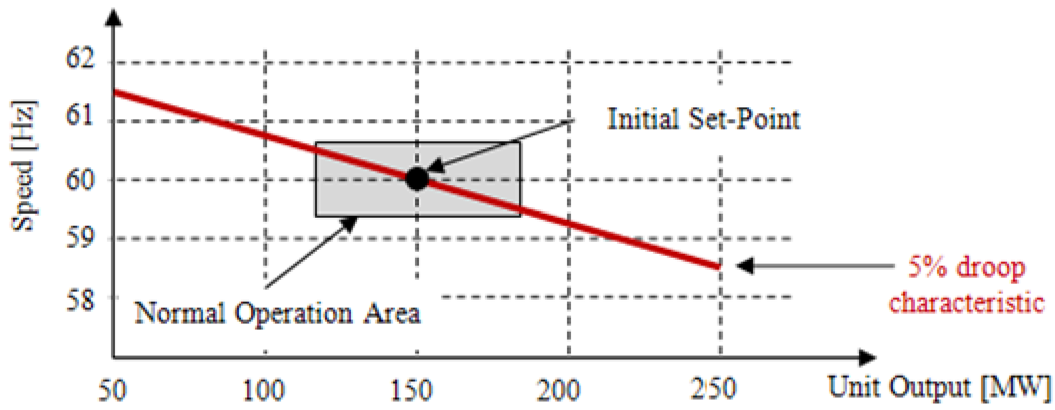
[50] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

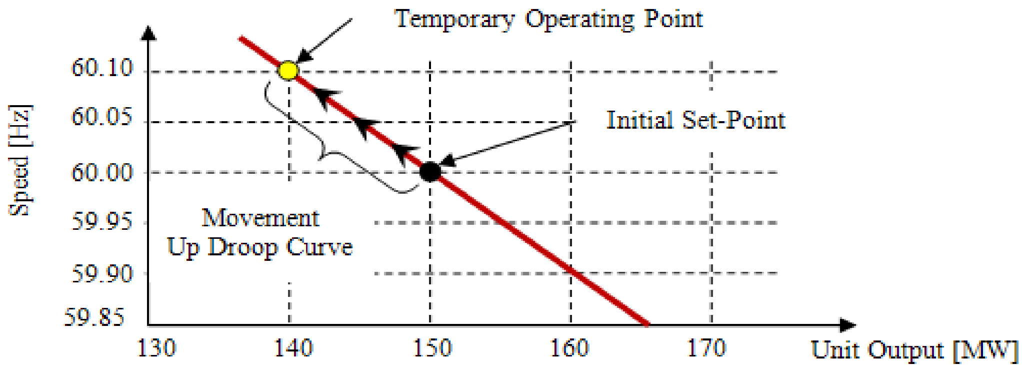
[51] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

Exhibit 2-12 Governor Characteristic Curve (Droop Characteristic)



Source: Electric Power Research Institute, 2009, p. 4-17, used with permission [52]

Exhibit 2-13 Governor Control—New Operating Point



Source: Electric Power Research Institute, 2009, p. 4-8, used with permission [53]

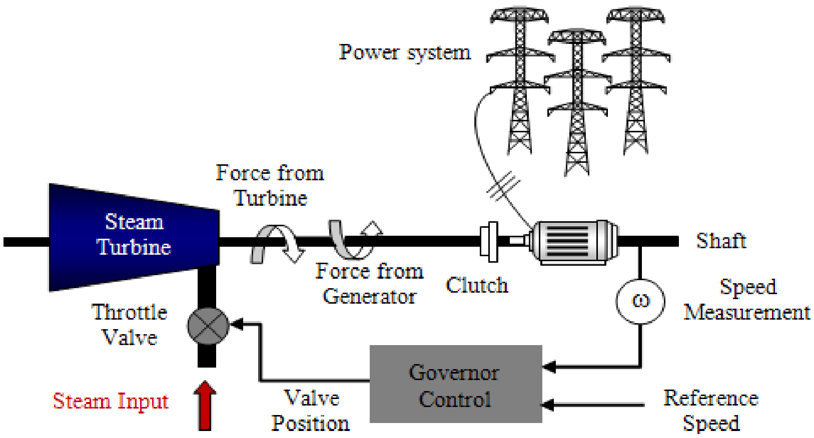
Primary control does not provide complete frequency regulation because it does not return the frequency to its nominal value, and it does not consider the cost of the power used for control. Primary control is designed for a single generator, along with other generators, to prevent the frequency from experiencing further changes. The main reason for such an approach is the need for very fast control response—essentially as soon as the disturbance occurs. Because of the fast response required and a lack of equally fast communication among generators and with the control center, primary frequency control acts in a distributed and independent manner. This is also the main reason for the primary control to arrest the frequency deviations only, rather than to try to reestablish it at its nominal value. If all generators tried to match the power demand and

[52] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

[53] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

return the frequency to its nominal value in a distributed way and at the same time, there would be competition among the generators resulting in oscillations. Exhibit 2-14 illustrates a typical primary control hardware setup.

Exhibit 2-14 Typical Primary Governor Control



Data Source: Adapted, with permission, from EPRI (2009), Figure 4-10, p.4-11.[54]

The ideal system component for effecting primary control is a (or a limited number of) large baseload unit(s) with a considerable moment of inertia in order to absorb and arrest the perturbation to the overall power system. Such a need is best served by coal-fired power plants, since other operational constraints keep nuclear plants from accepting primary governor control.

After the primary control arrests frequency deviation, reestablishing the nominal frequency is left to the secondary control: implementing automatic generation control coordinated by the balancing authority and the reliability authority.

2.2.2 Secondary Frequency Control

The primary frequency control effected via governor control typically controls a single unit and it does not return frequency to nominal value (60 Hz). On the other hand, secondary frequency control uses automatic generation control (AGC)[55] to control multiple generators inside a balancing authority area and restore frequency to its nominal value. AGC generators return frequency to nominal value by adjusting power plants' power outputs. The balancing authority

[54] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

[55] The NERC Glossary defines "automatic generation control" as "equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction."

monitors total supply (generation and import), total demand (load demand, losses, and export) and frequency inside its area and computes the area control error. [56]

Recall from Section 2.1.5 above that the ACE is difference between net scheduled and actual interchange. If the ACE is not zero, the balancing authority sends signals to selected generators to adjust their outputs to drive ACE to zero. These generator units are called regulating units. The role of a balancing authority is to ensure that the tie-line flows are as planned and, along with other balancing authorities, to maintain frequency within acceptable limits. Each interconnection has one or more balancing authorities as shown in Exhibit 2-15. AGC systems must control enough generating capacity to supply the balancing authority's internal demand and losses and scheduled interchanges while maintaining the nominal frequency. An AGC system must not interfere with neighboring balancing authorities' normal operations. Each AGC should maintain actual net interchange of its balancing authority close to its scheduled interchange.[57]

Exhibit 2-15 Number of the Balancing Areas[58]

Interconnection	Balancing Authorities
Eastern	90
Western	30
ERCOT	1
Quebec	1

There are three common AGC implementations:[59] constant frequency control (CFC), constant net interchange control, and tie-line bias control. Constant frequency control AGC is common for interconnections with a single balancing authority, such as ERCOT or Quebec. CFC AGC adjusts the power output of the power plants based only on the frequency deviations. If CFC is used in interconnections with more than one balancing authority, it could result in erratic behavior and power swings. Constant net interchange control AGC controls the interchange flows only and ignores frequency deviations. This type of control could be used when a balancing authority loses its AGC frequency source. The tie-line bias control is the most common AGC control method in interconnections with multiple balancing authorities. Under this control method, after frequency deviation is arrested, the balancing authority responsible for

[56] The NERC Glossary defines "area control error" as "the instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error."

[57] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

[58] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

[59] EPRI, *Power System Dynamics Tutorial*, Final Report, Palo Alto, California, July 2009.

disturbance is responsible for returning frequency to its nominal value. Recall from Section 2.1.5 (Equation 1) that ACE for a tie-line control is defined as:[60]

$$ACE = [Actual\ Net\ Interchange - Scheduled\ Net\ Interchange] - 10 \cdot B \cdot [Actual\ Frequency - Scheduled\ Frequency] - Correction\ for\ Meter\ Error \quad (2)$$

where B is the frequency bias constant. The B parameter is an estimate of the balancing authority's frequency response characteristic. This is the same as β shown in Exhibit 2-2 but estimated for a single balancing authority only. The B parameter is hard to calculate accurately because it depends on time of the day, load size and type, the size of disturbance, and other factors. Some balancing authorities pay great attention to parameter B estimation due to its role in ACE calculation.

Prior to January 1997,[61] best practices for secondary control implementation included use of the A1 and A2 method. The A1 and A2 method refers to having the ACE comply with the A1 and A2 control criteria with 90 percent conformance. The A1 criterion requires the return of ACE to zero every 10 minutes. The A2 criterion requires the average of ACE to be within $\pm L_d$ for each 10-minute period. L_d is the compliance limit for the A2 criterion or the "allowable limit of average deviation surveys" obtained from the annual surveys included in the control performance criteria training documents.

The A1 and A2 criteria have been replaced as a best practice for secondary frequency control because of the lack of a theoretical basis for the A1 and A2 criteria, and therefore the inability to relate these criteria to any reliability parameter. They have been ruled out as being based on "mature operating experience and judgment" [62] and not suitable to the needs of today's market. Additionally, the A1 limit would unnecessarily show a violation of the standard if ACE were close to zero for more than ten minutes. This could result in inefficient generation dispatch. The A1 and A2 criteria could also allow the control areas to operate just above the lower A2 limit 99 percent of the time as long as the ACE would cross zero once every 10 minutes.

Contrary to the older A1 and A2 method, the current Control Performance Standards, CPS1 and CPS2 are statistical methods with a basis in frequency base theory. The CPS1 utilizes the impact of ACE measurements on frequency over a 12-month period. By doing so, it can refer different actions to different control areas for variations in the interconnection efficiency while it takes other factors into account, such as the size of the control area and nature of the deviation (load/generation). CPS2, on the other hand, places limits on the fluctuations in the ACE value.

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[60] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I),* Washington, D.C., 2009.

[61] B.J.Kirby, J. Dyer, C. Martinez, Rahmat A. Shoureshi , R. Guttromson, and J. Dagle, *Frequency Control Concerns in North American Electric System,* Oak Ridge National Laboratory, 2002, available at http://www.ornl.gov/sci/btc/apps/Restructuring/ORNLTM200341.pdf (accessed September 16, 2010).

[62] Control Performance Standards. http://www.nerc.com/docs/oc/ps/tutorcps.pdf (accessed August 18, 2010).

With this approach, the historic frequency data replaces the A2, making the ACE control more realistic.

The non-linear frequency portion of the CPS could be attractive to control areas with better control systems, as well as an incentive for the weakly-controlled control areas to invest more in their control system. However, the CPS system is still vulnerable to net unscheduled power flows. Moreover, a coherence analysis of data from several control areas has revealed inconsistency in the level of tracking.[63] This analysis has shown the CPS approach to be highly case sensitive and often worse than the A1 and A2 method.

2.2.3 Tertiary Frequency Control

Tertiary control is part of the regular market clearing mechanism. Once the nominal frequency is restored, AGC-assigned generation should be substituted by energy obtained through regular energy market procedures, releasing the AGC generation for future control actions. Tertiary control acts on minute-to-hours time scale.

2.2.4 Time Control

The system frequency is never exactly 60 Hz, and time control is responsible to keep long term frequency average as close to 60 Hz as possible. For this purpose, a single interconnection time monitor compares the time provided by the National Institute of Standards and Technology (NIST) to time obtained using system frequency, and if there is a significant difference, the time error monitor notifies the Reliability Coordinators in each Interconnection and corrective action is carried out by the balancing authorities.[64] On March 18, 2010, FERC initiated a Notice of Proposed Rulemaking to remand the proposed revised NERC-developed Time Error Correction Reliability Standard (BAL-004-1) in order for NERC to develop several modifications to the proposed Reliability Standard.[65,66]

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[63] B.J.Kirby, J. Dyer, C. Martinez, Rahmat A. Shoureshi, R. Guttromson, and J. Dagle, *Frequency Control Concerns in North American Electric System*, Oak Ridge National Laboratory, 2002, available at http://www.ornl.gov/sci/btc/apps/Restructuring/ORNLTM200341.pdf (accessed September 16, 2010).

[64] NERC Resources Subcommittee, *Balancing and Frequency Control (Part I)*, Washington, D.C., 2009.

[65]NERC and other parties subsequently filed comments on April 28, 2010 (*Time Error Correction Reliability Standard*, Comments of the North American Electric Reliability Corporation in Response to Notice of Proposed Rulemaking, Docket No. RM09-13-000 (April 28, 2010)), requesting FERC to host a technical conference to consider removing the Time Error Correction Standard. On August 20, 2010, NERC filed a request for FERC to defer action regarding the BAL-004-1 Time Error Correction standard until August 20, 2011, to allow NERC sufficient time to conduct research and analysis to determine the usefulness of Time Error Corrections and propose appropriate follow-on actions (*Time Error Correction Reliability Standard*, Motion to Defer Action, Docket No. RM09-13-000 (August 20, 2010)).

[66] On Feb 22, 2011 NERC submitted a status report on the development of Reliability Standard BAL-004-1 — Time Error Correction which was six months from the date of the Motion for informational purposes its status report as per the Motion to Defer Action filed on August 20, 2010. The NERC Operating Committee passed a motion in Dec 2010 directing that the Resources Subcommittee develop a field trial to eliminate manual Time Error Correction. (*continues on next page*) (*continued from previous page*) NERC has developed a communication plan, to determine the path moving forward.

3 **Policy Aspects of the Frequency Stability Issue**

While the technical implementation of frequency control is directly responsible for an interconnection's frequency stability, the policy, i.e., standards and regulations, have both direct and indirect effects on the ability to implement the technical control. NERC is directly involved in formulating operational requirements. The Federal Energy Regulatory Commission (FERC) is responsible for overseeing NERC's activities and monitors and investigates the electrical energy market[67].

3.1 Standards and Regulations Indirectly Related to Frequency Stability (Impact of Market Design)

Unlike the regulatory restructuring of the 1920s and 1930s, the restructuring of the electric power industry over the last 20 years is not motivated by industry misconduct but a desire to improve industry efficiency by spurring competition. Furthermore, a more open and competitive landscape has been further enabled by technological innovations and policy changes that lowered barriers to entry into the energy market. Over the last two decades, several actions by the FERC have transformed the electric power industry into an unbundled and deregulated market.

Before the passage of the Energy Policy Act of 1992 provided a firm legal basis for competitive energy markets, FERC fostered this market transition beginning in the mid-1980s by encouraging the use of market-based rates for wholesale electric power. Thirty-one requests to use market-based rates for the sale of wholesale electric power were handled by FERC between 1985 and mid-1991.[68] Armed with significant authority to command transmission-owning utilities to wheel power and to mitigate barriers to accessing the transmission and distribution infrastructure, FERC issued a series of policy statements and Orders that essentially created the competitive, deregulated, wholesale electric power market in the United States.

In July 1993, with the intent of settling disputes over the use of transmission services by direct negotiation instead of litigation before FERC, FERC issued a policy statement encouraging formation of Regional Transmission Groups.[69] The following spring FERC instituted guidelines granting third-parties comparable access to the transmission and distribution system at similar

NERC expects the communication plan to begin in the Spring 2011, followed by the beginning of the Field Test. NERC will provide an additional filing on or before August 20, 2011 to FERC.

[67] *About FERC*, last modified June 28, 2010, http://www.ferc.gov/about/ferc-does.asp (accessed on October 1, 2010).

[68] EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*," October 2000, p. 62. For a helpful overview, see also Lamoureux, M., "FERC's Impact on Electric Utilities," *IEEE Power Engineering Review*, August 2001.

[69] Policy Statement Regarding Regional Transmission Groups, 58 FR 41,626 (August 5, 1993), FERC Stats. & Regs. ¶ 30,976 (1993) (RTG Policy Statement) - summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*, October 2000, p. 62.

terms and conditions as the owners of the system.[70] By issuing its Transmission Pricing Policy Statement in October 1994, FERC recognized the need to realign transmission pricing methodology with a competitive market by going beyond simple postage stamp or contract path pricing.[71] These actions laid the groundwork for subsequent FERC Orders which definitively deregulated the electric power industry and established a truly competitive market.

Paramount among the many actions of FERC that established a competitive market were the issuing of Orders 888 and 889, (in 1996) and Order 2000 in 1999. Issued in April 1996, Order 888[72] established FERC's legal authority to require utilities owning transmission lines to permit the use of their transmission assets by third parties. Three critical concerns were addressed by Order 888: opening access of transmission lines to competing power generators, the unbundling of functional charges, and establishing a mechanism for recovery of "stranded costs." The provisions of Order 888 allowing for recovery of stranded costs and reinforcing existing contracts were minor, but essential, details to ease the transition to competition. Consequently, they had little influence on the eventual equilibrium point of the new competitive market.

The major and lasting provisions of Order 888 that enabled truly competitive markets for wholesale electric power by promoting fair, practical, and open access to the transmission and distribution system are discussed below.

Order 888 required utilities to publish separate rates for wholesale generation, transmission, and ancillary services; this action is often referred to as "functional unbundling." Furthermore, transparent information about capacity and submission of wheeling requests needed to be on a common electronic network. In addition, the Open Access Transmission Tariff requirement meant participating utilities, as of July 1996, must articulate the minimum required conditions in order to access point-to-point and network transmission services. While participation in power pools was not made mandatory by Order 888, participating utilities were required to file a pro forma tariff with the regional power pool by December 1996.

[70] *American Electric Power Service Corporation*, 67 FERC ¶ 61,168 (1994) - summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update,* October 2000, p. 62.

[71] *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Policy Statement, *FERC Statutes and Regulations* ¶31,005 (1994); 59 Fed. Reg. 55031, Nov. 3, 1994. (Policy Statement) and *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Docket No. RM93-19-001, 71 FERC ¶61,195 (May 22, 1995), -summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update,* October 2000, p. 62.

[72] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080 (April 24, 1996), 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (Order No. 888), order on reh'g, Order No. 888-A, 62 FR 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997) (Order No. 888-A), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), appeal docketed, Transmission Access Policy Study Group, et al. v. FERC, Nos. 97-1715 et al. (D.C. Cir.) [hereinafter Order No. 888] - Cited in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*, October 2000, p. 62.

Order 888 also established the principle of reciprocity in that a utility selling power via wheeling must permit the sale of wheeled wholesale power within their service territory by other utilities. Order 888 made FERC's Transmission Pricing Policy Statement, mentioned above, compulsory. Furthermore, transmission-owning utilities were required to set prices for network, point-to-point, and ancillary services related to the transmission of wholesale power. Through Order 888, FERC made transmission providers responsible for delivery of six core services: (1) scheduling, dispatch, and control (control of power in and out of a service area); (2) supply of reactive power and voltage control; (3) frequency regulation and response; (4) prevention and management of energy imbalances (i.e., handling discrepancies between scheduled and actual delivered power within the ± 1.5% tolerance); (5) operating and spinning reserve (in case of a system power deficiency); and (6) operating and supplemental reserve (to maintain supply as generation is brought on-line). The latter four services are optional, but the former two services must be purchased as part of a valid wheeling agreement.

Issued in conjunction with Order 888, FERC Order 889[73] facilitated competitive markets by assuring transparency, accuracy, and consistency in sharing of information critical to making intelligent competitive decisions. Order 889 established a common standard of conduct among power industry participants. In order to prevent gaming or obscuring of information, Order 889 required accounting systems for transmission, distribution, and generation facilities to be separate. Additionally, FERC Order 889 obligated all investor-owned utilities to share availability of transmission capacity, ancillary services, scheduling of power transfers, economic dispatch, current operating conditions, system reliability, and responses to systems conditions on an Open Access Same-Time Information System (OASIS; formerly referred to as Real-Time Information Networks). Order 889 created the obligation of investor-owned utilities to gather and supply information on power generation using the OASIS. Since the emerging non-profit regional Independent System Operators (ISOs) had the mission of impartially managing the power market, they undertook the role of administering the OASIS sites. The Internet-based OASIS went live in January 1997. In less than 4 years, 166 transmission-owning utilities were participating in OASIS and 23 Internet OASIS nodes were functioning.

In support of Orders 888 and 889, FERC issued Order 592[74] in December 1996 streamlining and changing the evaluation criteria involved in the process of receiving merger approval. Order 592 facilitates the accumulation of necessary financial and intellectual capital by new market entrants allowing them to compete effectively against entrenched players. Additionally, during 1997 and 1998 FERC approved five ISOs (PJM Interconnection, Midwest ISO, California ISO, New England ISO, and the New York ISO). Several positive market developments occurred because

[73] *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 75 FERC ¶ 61,078 (April 24, 1996), 61 FR 21,737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 (1996), order on reh'g, Order No. 889-A, 62 FR 12,484 (March 14, 1997), FERC Stats. & Regs. ¶ 31,049 (1997), order on reh'g, Order No. 889-B, 81 FERC ¶ 61,253 (1997) - summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*, October 2000, p. 62.

[74] *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 61 FR 68595 (Dec. 30, 1996), III FERC Stats. & Regs. ¶ 31,044 (Dec. 18, 1996), reconsideration denied, Order No. 592-A, 62 FR 33341 (1997), 79 FERC ¶ 61,321 (1997) (Policy Statement).

of the issuance of Orders 888 and 889. Specifically, existing generation facilities had clear and tangible economic drivers to invest in becoming more efficient, and new merchant plants, creating more competitors, were built due to the economic opportunity created by these Orders.

However, a second tier of significant barriers to the development of competitive electric power markets remained and quickly became evident. Owners of transmission and distribution assets were perceived to be discriminating against independent power companies (those that did not own transmission assets). Second, functional unbundling under Order 888 failed to provide adequate separation between the transmission business and the business of marketing and selling power. This limited separation further facilitated discrimination against market players without transmission assets. Another issue was the incomplete regionalization of grid operations; in other words, ISOs were formed in some regions but not in others. The subsequent rise in market players and trading following Orders 888 and 889 significantly impacted grid performance, particularly with respect to reliability and congestion. Consumer benefits from Orders 888 and 889 were muted by pancake pricing, in which a fee was tacked on every time power crossed a regional boundary.

Responding to the market inefficiencies that remained following the implementation of Orders 888 and 889, FERC took further action to drive the wholesale electric power market to a more competitive landscape. FERC ambitiously used further regionalization of the grid to mitigate these issues through the formation of fully independent regional transmission organizations (RTOs).[75] FERC issued Order 2000 in December 1999[76] mandating the creation of RTOs throughout the United States, albeit participation is voluntary. The intent of Order 2000 was to remove the residual barriers to a competitive market.

Order 2000 delineated several of FERC's expectations such as regional operation of high-voltage transmission, elimination of discriminatory practices leaving minimal economic or operational obstacles to trade, open access to the network and information about the network (e.g., OASIS), and true access and exit from the transmission network establish ease of opportunity. To meet these expectations Order 2000 established that RTOs should have full independence from market participants, as well as responsibility and authority regarding short-term grid stability, operational control of all transmission assets in their region, and an appropriate regional configuration. In support of these characteristics, each RTO assumed key market and technical functions within its area, such as design and administration of tariffs, management of congestion and parallel path flows, and continual development of OASIS, monitoring the market, and planning and expansion of transmission assets.

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[75] A clear and succinct yet detailed description of RTOs and their roles and responsibilities is given in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update*, October 2000, p. 69-72.

[76] *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (December 20, 1999), 65 FR 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 FR 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), affirmed sub nom. Public Utility District No. 1 of Snohomish County, Washington, v. FERC, 272 F.3d 607 (D.C. Cir. 2001) - summarized in EIA, *The Changing Structure of the Electric Power Industry 2000: An Update,* October 2000, p. 62.

Remaining barriers to entry for new market participants were subsequently removed by FERC Orders 2003 and 2006. Order 2003 issued in December 2004 established Large Generator Interconnection Agreements and Procedures facilitating power inputs from asynchronous generators such as wind. Issuance of Order 2006 in May 2005 established Small Generator Interconnection Agreements and Procedures to facilitate the addition of small power inputs, facilities with significantly less stored kinetic energy to the grid. Also, Order 2006 specifically exempts small wind generators from requirements to supply reactive power.[77]

While not an inclusive list of all of the FERC actions that shaped the electricity power market, these are the actions that had the most influence on market response to deregulation that is relevant to affecting the frequency characteristics of the system. The predominant effect on the technical characteristics of the electric power generation, transmission, and distribution system is the increase in the proportion of distributed generation in the system. One of the salient consequences of this shift is its influence on frequency stability and response discussed below. Specifically, the FERC Orders established market conditions that deeply influenced the investment decisions with respect to new generation projects changing the mix of the generation portfolio.

The separation of generation and transmission operations instituted by Order 888, and completed by Order 2000, removed the reliability of the transmission system from the economics related to generation investment decisions. Specifically, grid reliability is the concern of the RTO not the investors in a generation project. Therefore, when considering facility choice, the higher reliability of smaller distributed units is not counterbalanced by the possible detrimental effects on grid reliability.[78] Furthermore, economies of scale for generation facilities are not as dramatic as they were 50 years ago; hence, smaller distributed systems can make economic sense. The greater and guaranteed accessibility to the market created by the FERC Orders mentioned above increased the number of possible entrants for whom the lower initial capital demands of distributed generation are more palatable. Even for entrenched market players, since guaranteed capital recovery was eliminated in deregulated markets, the ability to raise capital for traditional large baseload generation is also constrained, favoring distributed generation.

A direct consequence of Orders 888 and 2000 is the elimination of incentives for a generating business to invest capital in adding transmission capacity that may be required to bring a large baseload unit on-line. Hence, the capital requirements for the transmission from an investor’s facility to the grid and any incremental investment in the grid to absorb the large quantities of power from a new traditional baseload facility do not appear to be justifiable, nor are costs recoverable as under a traditional, regulated utility model. But the transmission and distribution systems will have niches that can absorb the low to moderate power inputs of distributed generators. These considerations are exacerbated by the congestion issues caused by

[77] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 70 FR 34189 (June 13, 2005), FERC Stats. Regs. ¶ 31,180 (2005) (Order No. 2006), order on reh'g, Order No. 2006A, 70 FR 71760 (November 30, 2005), FERC Stats. Regs. ¶ 31,196 (2005) P 387.

[78] Willis, L., and Scott, W., *Distributed Power Generation*, CRC Press, New York, 2000.

deregulation. Increased congestion is also the result of deregulated markets allowing larger and more complex purchases over larger distances. The congestion issue may also encourage smaller generation builds closer to loads. Similarly, the lack of guaranteed cost-plus economics in deregulated markets make considerations such as the cost, logistics, and availability of fuel as well as potential options to be feed-flexible, tilt some investment decision toward distributed generation options.

A final consequence of the FERC Orders is that, while eliminating obvious price inequities such as pancake pricing, the deregulated market that resulted, now encourages a generator to add new capacity as close to their customer as possible in order to minimize cost. Distance directly impacts generator-born costs for transmission losses and the charges for wheeling power. As such, the optimization of the size of generation facility can often favor a portfolio of distributed generation assets versus one large central facility.

The market response to deregulation was the addition of considerable distributed generation capacity. Emerging governmental actions such as state-level renewable energy standards are too nascent to know their specific impact on the generation portfolio, but one would anticipate they would reinforce the trend toward small distributed power generation. As the generation portfolio changes, so do the technical characteristics of the system, leading to new challenges in maintaining system performance.

The net effect of the deregulation process, as relevant to frequency stability, is the major shift towards building small generators. This resulted in the decreased system moment of inertia that is critical before and during primary control response.

3.2 Standards and Regulations Directly Related to Frequency Stability (Impact on Frequency Control Practices)

NERC was formed in 1968, shortly after the Northeast U.S. blackout in 1965. It was a voluntary organization with the function of promoting reliable and efficient power system service. After 1996, when FERC Order No 888 was adopted, it became clear that voluntary compliance was no longer adequate. In 2005, Part II of the Federal Power Act was amended by adding section 215 in which Congress directed the development of mandatory and enforceable electricity standards and establishment of the Electric Reliability Organization (ERO) to monitor and enforce the reliability standards.[79] In July 2006, NERC was granted the role of the ERO.[80] As the ERO, NERC proposes and enforces reliability standards for the bulk power system in the United

[79] Energy Policy Act of 2005.

[80] *North American Electric Reliability Corp*., 116 FERC ¶ 61,062 (ERO Certification Order), *order on reh'g & compliance*, 117 FERC ¶ 61,126 (July 20, 2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009), p. 4.

States.[81] However, all reliability standards are subject to FERC approval. The first set of 83 mandatory reliability standards was approved by FERC Order No. 693 in 2007.[82] These standards are grouped into 14 categories:

1. Resource and Demand Balancing (BAL)
2. Communications
3. Critical Infrastructure Protection
4. Emergency Preparedness and Operations
5. Facilities Design, Connections, and Maintenance
6. Interchange Scheduling and Coordination
7. Interconnection Reliability Operations and Coordination
8. Modeling, Data, and Analysis
9. Nuclear
10. Personnel Performance, Training, and Qualifications
11. Protection and Control
12. Transmission Operations
13. Transmission Planning
14. Voltage and Reactive

The first category, Resource and Demand Balancing, is relevant to maintaining frequency at 60 Hz. This category consists of multiple individual standards shown in Exhibit 3-1 that support the FERC-defined ancillary services "Regulation and Frequency Response Service" and "Operating Reserve."

[81] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006), p. 1.

[82] Order No. 693, *supra* note 8 at P 1.

Exhibit 3-1 Resource and Demand Balancing Reliability Standards[83]

Number	Title	Purpose	Parameters/Limits	Mandatory Implementation Date[84]/Applicability
BAL-001-0.1a	Real Power Balancing Control Performance	To maintain interconnection steady-state frequency within defined limits by balancing real power demand and supply.	• NERC Operating Committee reviews and sets as necessary limit for CPS1 (ACE variability). The limit is derived from a targeted frequency bound • Limit for CPS2 (ACE magnitude) is the targeted root-mean-square value of ten minutes average frequency error over a year	05/13/09 Balancing Authorities
BAL-002-0[85]	Disturbance Control Performance	To ensure that Balancing Authority is able to utilize its Contingency Reserve such that after a disturbance (loss of supply) frequency is returned within defined limits. *This standard is limited to the loss of supply and does not include the loss of load.	• Contingency Reserve should at least cover the most severe single contingency • Disturbance Recovery Period = 15 minutes • Contingency Reserve Restoration Period = 90 minutes • MW size of disturbance should be measured as close as possible at the site of the loss	06/18/07 Balancing Authorities; Reserve Sharing Groups; Regional Reliability Organizations
BAL-002-WECC-1[86]	Contingency Reserve	To ensure that Balancing Authority is able to utilize its	• Contingency Reserve = min[an amount of reserve equal to loss of the most severe	Balancing Authority; Reserve Sharing Group

[83] NERC Reliability Standards, available at http://www.nerc.com/page.php?cid=2|20 (accessed on September 9, 2010).

[84] http://www.nerc.com/filez/standards/Mandatory_Effective_Dates_United_States.html (accessed on September 9, 2010).

[85] This standard has been modified to address Order No. 693 directives "develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2" contained in paragraph 321. New version BAL-002-1 was adopted by Board of Trustees on August 5, 2010, and it is awaiting regulatory approval.

[86] This standard is awaiting regulatory approval.

		Contingency Reserve such that after a disturbance (loss of generation or transmission equipment) frequency is returned within defined limits.	single contingency, (3% of the load + 3% of net generation)] (+Interchange Transaction) • At least half of the contingency reserve shall be spinning reserve • Spinning reserve has governor or other control • Acceptable reserve must be fully deployable within 10 minutes • Disturbance Recovery Period = 15 minutes • Contingency Reserve Restoration Period = 90 minutes	
BAL-003-0.1b	Frequency Response and Bias	To provide a consistent method for calculating the Frequency Bias component of ACE	• Frequency Bias Setting ≥ Balancing Authority's Frequency Response • Frequency Bias Value is based on straight-line[87] or variable[88] function of Tie Line deviation versus Frequency Deviation • AGC operating mode is tie-line frequency bias • Frequency Bias setting should be at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change	5/13/2009 Balancing Authorities
BAL-004-0[89]	Time Error Correction	To ensure Time Error Correction that will not affect	• Frequency schedule offset is 0.02 Hz and	06/18/07

[87] The BAL-003.01b states that "the Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours."

[88] The BAL-003.01b states that "the Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency."

[89] New version BAL-004-1 was approved by Board of Trustees on September 13, 2007, and it is awaiting regulatory approval.

		the reliability of the system	normal Frequency Bias setting, or • Net Interchange Schedule offset (MW) is 20% of Frequency Bias Setting	Reliability Coordinators ; Balancing Authorities
BAL-004-WECC-01	Automatic Time Error Correction	To maintain Interconnection frequency and to ensure effective Time Error Correction that will not affect the reliability of the system	• Automatic Error Correction is a part of AGC • Each Balancing Authority should be able to switch between different AGC operating modes	07/01/09 Balancing Authorities
BAL-005-0.1b	Automatic Generation Control	To provide requirements for AGC necessary for ACE calculation and deployment of Regulating Reserve	• AGC controls Regulating Reserve to meet the Control Performance Standards • AGC operating mode is tie-line frequency bias • AGC operates continuously • Data acquisition and ACE calculation at least every six second • All dynamic schedules should be included in ACE calculation as part of Net Scheduled Interchange • Ramping rates should be included in the Scheduled Interchanged values for ACE calculation • All tie line flows should be included into calculation	05/13/09 Balancing Authorities; Generator Operators; Transmission Operators; Load Serving Entities
BAL-006-1	Inadvertent Interchange	To ensure that Balancing Authorities do not depend over the long time on other Balancing Authorities for meeting their demand		05/13/09 Balancing Authorities

BAL-502-RFC-02[90]	Planning Resource Adequacy Analysis, Assessment and Documentation	To establish common criteria for the analysis, assessment and documentation of Resource Adequacy	• Planning reserve margin such that it satisfies "one day of loss in 10 year" criterion	Planning Coordinator
BAL-STD-002-0	Operating Reserve	To address Operating Reserve requirements of the WECC	• Minimum Operating Reserve = Regulating Reserve + Contingency Reserve[91] + Additional Reserve • Reserve should be restored within 60 minutes	06/18/07 Balancing Authority; Reserve Sharing Group

[90] New version BAL-502-RFC-02 was approved by the Board of Trustees on August 5, 2009.

[91] BAL-502-RFC-02 defines the contingency reserve as "The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or (b) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation."

The Regulation and Frequency Response Service, according to FERC, is necessary to provide power balance, and to maintain Interconnection frequency at 60 Hz. This service is achieved predominantly using automatic generation control equipment.[92] On October 15, 2002, NERC filed comments on the Commission's Notice of Proposed Rulemaking on Standard Market Design. [93] NERC recognized that Regulation and Frequency Response ancillary service only addresses AGC as the frequency response and does not include primary frequency response (governor control) as part of the service. NERC suggested changing the name of the Regulation and Frequency Response ancillary service to Regulation service so that the name corresponds to industry practice. Furthermore, NERC recommended deciding if governor characteristic should be a part of Frequency Response ancillary service or a part of generator interconnection and operation agreement. In addition, it recommended that:[94]

- Each unit larger than 10 MW should be equipped with governor control for frequency response; and
- Units that are equipped with governor control should be able to immediately respond to abnormal frequency conditions and have droop characteristic of five percent.

When the NERC reliability standards became mandatory in 2007, these NERC guidelines were not included in the BAL-003-0 standard, Frequency Response and Bias. However, in Order 693, the Commission directed NERC to develop certain modifications for this standard. These includes (1) determining the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met;[95] and (2) developing a modification to BAL-003-0 that defines the necessary amount of frequency response needed for reliable operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.[96]

On March 18, 2010, FERC issued an Order[97] setting a deadline for compliance. It directed NERC to submit required modifications within six months. On April 19, 2010, NERC requested a hearing and clarification of the FERC's Order.[98] NERC submitted that there was a technical

[92] Order No. 888, *supra* note 72, states that "Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load," schedule 3, original sheet No. 117.

[93] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Comments of the North American Electric Reliability Council, Docket No. RM01-12-000 (October 15, 2002) available at http://www.nerc.com/docs/docs/ferc/RM01-12-000-SMD.pdf (accessed on September 15, 2010).

[94] NERC, *NERC Operating Manual.* New Jersey. 2004.

[95] Order No. 693, *supra* note 8 at P 369.

[96] Order No. 693, *supra* note 8 at P 370 and P 372.

[97] *Order Setting Deadline for Compliance*, 130 FERC ¶ 61,218 (March 18, 2010).

[98] *Order Setting Deadline for Compliance*, Request of the North American Electric Reliability Corporation for Clarification and Rehearing of the Order Setting Deadline for Compliance, Docket No. RM06-16-010, p. 9 (April 19, 2010) [hereinafter Docket No. RM06-16-010].

error in the March 18 Order and that six months was an unreasonable time for developing a frequency response standard, given the complexity of the frequency response issue. Furthermore, NERC stated that it plans on issuing a Recommendation to the Generation Owners and Generator Operators so that they report back to NERC on their operating status with respect to governor installation,[99] governors free to respond,[100] governor droop,[101] and governor limits.[102] These recommendations correspond to guidelines of the NERC Operating Policy in 2004.[103] This was followed up with an Order Granting Rehearing for Further Consideration and Scheduling a Technical Conference (issued May 13, 2010).[104] The Technical Conference was held on September 23, 2010. PJM also submitted a request for clarification and rehearing on the March 18 Order. PJM stated that frequency response requires explicit definition[105] because inertia, governor response, regulation, economic dispatch, and reserve response all provide frequency response and they are under the control of different functional entities. In addition, PJM suggested that the old policies need to be reviewed so they correspond to the current environment. PJM concluded that in the March 18 Order, the Commission was interpreting the NERC guidelines about the governor control as a requirement. However, there has never been such requirement.[106] In the meantime, due to the lack of a clear and well-defined frequency response reliability standard, the regional entities, reliability councils and balancing authorities try to maintain 60 Hz frequency, keep system stability, provide reliable supply, and comply with existing reliability standards.

For example,

- PJM requires that:

[99] Docket No. RM06-16-010, *supra* note 98, at p. 12, "Governor Installation - Whether generating units with nameplate ratings of 10 MW or greater are equipped with governors operational for frequency response."

[100] Docket No. RM06-16-010, *supra* note 98, at p. 12, "Governors Free to Respond – Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem."

[101] Docket No. RM06-16-010, *supra* note 98, at p. 12, "Governor Droop – All turbine generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0.036 Hz (± 36 MHz)."

[102] Docket No. RM06-16-010, *supra* note 98, at p. 13, "Governor Limits – Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics."

[103] NERC, *NERC Operating Manual.* New Jersey. 2004.

[104] *Mandatory Reliability Standards for the Bulk Power System* , Order Granting Rehearing for Further Consideration and Scheduling Technical Conference 131 FERC ¶ 61,218 (May 13, 2010).

[105] Docket No. RM06-16-010, *supra* note 98, at p. 2, PJM explains that "Based upon the Commission's statement set forth in Paragraph 13 of the March 18 Order, it appears that the Commission equates "frequency response" to "generator governor response.""

[106] Docket No. RM06-16-010 , *supra* note 96 at p. 2, PJM states that "Through the March 18 Order, the Commission is extending that guide and interpreting that guide as a requirement, despite the absence of any historical ad hoc governor response requirement."

- Any capacity resource with a capability of more than 10 MW must be explicitly modeled in the PJM Energy Management System.[107] In addition, PJM requires that all generators who participate in the capacity market are required to submit real-time tele-metered data (real power and reactive power). However, generators with capacity of less than 10 MW that do not participate in the capacity market may not be required to supply real-time information.
- Generators that participate in the regulation market must have governor control and be able to receive AGC signal.[108] PJM does not specify an exact number for droop characteristics, but in training material, they use governor with 5 percent droop characteristic (NERC recommendation).[109]

- ISO New England requires that every market participant with a capability of 10 MW or greater provide and maintain a functioning governor. In the ISO New England area, the governor should have 5 percent droop characteristic unless technical consideration dictate otherwise.[110]
- WECC is drafting WECC-0070 Governor Droop Criterion.[111] Currently, the WECC minimum operating reliability criteria requires the governor to be set at five percent. However, WECC is looking for more technical droop characteristic settings or control. It is considering an effective governor droop response for an area and a range for droop settings.

The NERC Resource and Demand Balancing standards support the FERC Operating Reserve ancillary service that is required to serve load in a case of a contingency and used to return frequency to 60 Hz when a large generator or a transmission line unexpectedly fails. FERC defines two types of operating reserves: spinning reserve and supplemental reserve.[112] The spinning reserve serves load immediately after contingency and it is usually provided by on-line generating units that are not fully loaded. The supplemental reserve serves the load within a short

[107] PJM, *Manual 14D – Generator Operational Requirements*, effective June 1, 2010, Energy Management System Model, p. 22.

[108] PJM, *Manual 11 - Energy & Ancillary Services Market Operations*, effective June 23, 2010, Section 3: Overview of the PJM Regulation Market, p.54.

[109] Lovasik, C., *NERC Resource and Demand Balancing Standards*, available at http://pjm.acrobat.com/p93522443/ (accessed on September 15, 2010).

[110] ISO New England, *Operating Procedure No. 14 - Technical Requirements for Generators, Demand Resources and Asset Related Demands*, effective date June 1, 2010, requires specific governor control: “The Market Participant is obligated to provide and maintain a functioning governor on all Generators with a capability of ten (10) MW or greater. The governor should be set in accordance with industry standards unless technical considerations dictate otherwise (governor droop set at five percent [5%]). If technical considerations dictate otherwise, ISO should be so informed by the Designated Entity per Master Local Control Center Procedure No. 10. The Market Participant is responsible for periodic testing and maintenance of the governor.”

[111]http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=70&Source=/Standards/Development (accessed on September 15, 2010).

[112] Order No. 888, *supra* note 72, Original Sheet No. 122 and Original Sheet No. 123.

period of time after contingency. Similarly to FERC, NERC defines operating reserve as combination of spinning and non-spinning reserve. However, its operating reserve definition includes regulation, load-forecasting error, outages and area protection.[113] Furthermore, NERC adds interruptible load as an operating reserve. The NERC definition includes both commercial and forecasting issues and reliability issues, while the FERC definition includes only reliability issues.[114] Commercial and forecasting issues include power imbalance due to load-forecasting errors, generation and transmission maintenance, and load diversity while the reliability issues include power imbalance due to unexpected outages.

The most concerning issue is the observed decline in the primary frequency response and its effect on the frequency stability. Until recently, qualified facilities smaller than 80 MW[115] were not required to provide spinning reserve for primary control at all. FERC, NERC, and the ISOs have recognized this limit as too high and currently all power plants larger than 10 MW are required to participate in primary control. This change does not seem to be sufficient to address lack of primary control, and the NERC standards committees are working on a new set of requirements which will define in much better terms how the primary frequency response should function to improve frequency response characteristic. Additional information is provided in the Appendix of this report.

[113] The NERC Glossary defines operating reserve as “That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.”

[114] Hirst, E., and Kirby, B. ,*Electric-Power Ancillary Services*, Tennessee: Oak Ridge National Laboratory, 1996.

[115] *Applicability of Federal Power Act Section 215 to Qualifying Small Power Production and Cogeneration Facilities*, 72 FR 14,254 (2007), “The Commission reasoned that, given the statutory directive that all users, owners and operators of the bulk-power system must comply with mandatory reliability standards under section 215, it may not be appropriate to allow QFs [qualified facilities] a continued exemption from compliance with the newly adopted mandatory and enforceable reliability standards that apply to generator owners and operators.”

4 Summary and Recommendations

Over the past decade, the frequency response of the North American interconnections has been slowly but consistently declining. This suggests that frequency stability is becoming more vulnerable to sudden supply and demand changes. NERC has identified this problem as one that requires significant effort by the electricity sector to ensure the continued reliability of the North American bulk power system. Some of the more likely and prominent constituents of the complex set of interrelated causes of this degrading frequency response include recent changes in:

- Total moment of inertia of generators on the interconnections, i.e., reduction in total moment of inertia due to movement toward smaller distributed generators
- The nature of the typical load; i.e., reduction in rotating loads
- Generator operations under competitive pressure (deregulated wholesale markets)
- Generator reserves under competitive pressure
- Insufficient or ineffective regulations and incentives to maintain frequency response

System frequency is difficult to regulate due to the complex interplay of the different technical and nontechnical factors, as well as the size of the interconnections. Technical difficulties are mostly caused by a declining frequency response characteristic and the time scale on which the primary control must respond. The cause of the declining frequency response characteristic cannot be definitively assigned. From a technical perspective the reduction in system inertia due to the movement to smaller distributed generators and a reduction in motor driven loads tend to negatively impact frequency response. Furthermore, some Smart Grid initiatives and direct and indirect regulations and standards have incentivized the deployment of small generators leading to a degradation of the interconnections frequency response. For example:

- Small generators are favored over large central plants since FERC introduced open transmission access and other deregulation-oriented Orders.
- Open transmission access reduced the Available Transmission Capacity of the interconnections at the same time that the unbundling of the transmission service did not provide any incentives for transmission owners to build additional transmission lines.
- Small generators can be built closer to the load, sometimes even located on the distribution system requiring no transmission access at all, thus avoiding transmission charges.
- Small, distributed generation is also encouraged and subsidized by different governmental programs such as Renewable Portfolio Standards. These small generators contribute to the solution of the transmission capacity problem and energy delivery reliability but under the current regulations cause problems for frequency response. Small generators have less moment of inertia than the large ones and under current regulations are not required to provide spinning reserve for primary control if smaller than 10 MW.

FERC seems to be fully aware of these issues and has requested that NERC develop a new comprehensive set of rules and regulations to address them. However, the declining frequency response characteristic and how to deal with it requires more analysis and clarification.

The following recommendations, made as part of the findings of this study, are separated into policy and standards, and technical recommendations.

Policy and Standards Recommendations

- More monitoring and analysis of the interconnections' operations should be conducted including generation and demand amount and type, disturbance types, and frequency response in order to better and more quantitatively understand the problem and enable more data driven and advanced real-time frequency control strategies.
- Standards should be more technically specific about the amount of required reserves and how they should be used, specifying reaction times, generation compositions, and type.
- A set of adjustable parameters should be established that can be deduced periodically from continuous system monitoring.
- Standards for the response time of primary and secondary control should be defined and enforceable.
- Policies should require more operators to provide some sort of primary frequency response contribution, either directly, through a pooling method, or through purchase as an ancillary service. It may be appropriate to use a penalty provision for not delivering appropriate primary frequency response support to the system.
- More specifically, policies regarding contributions to primary frequency response should require specific operating standards such as free-governor mode requirements or speed-droop regulations, or a more general set of frequency response standards or requirements.
- Policy response should require new, targeted data reporting requirements to assist with developing better updated performance standards.
- Policies should increase incentives for generators to bid for ancillary services.
- Construction of very large generating stations such as coal baseload generators should be encouraged in order to provide the power system with the increased moment of inertia that is critical during a disturbance.

Technical Recommendations:

Primary control is probably the most critical part of frequency control. If the primary control does not react properly, a perfectly functioning secondary control might not have a chance to respond at all. To address primary control issues, NERC could:

- Reexamine whether the commonly used droop of 5 percent is appropriate. This droop characteristic corresponds to 3 Hz deviations over a generator's entire generation range. Frequency deviations of +/-1.5 Hz are very unusual in North American interconnections.

- Reexamine whether the same droop should be used by small and large generators. Small generators can respond much faster than the large generators and might be more useful if using steeper droop.
- Clearly define and enforce spinning reserve dedicated to primary control.
- Define how fast the governor controller must respond based on real-time frequency response characteristic.
- Recommend real-time frequency response characteristic monitoring and its use for primary control algorithms.
- Require smaller generators to provide spinning reserve.
- Improved data collection efforts should be developed to better characterize the load and the magnitude of the effect, and development of system frequency response standards that appropriately address the dynamics and variability of primary load response.

Appendix - Recent Developments Regarding Frequency Instability

As the problem of frequency instability in the North American interconnections is a serious concern, activity on this subject is very high. Consequently, a considerable amount of relevant information was released between the end of the main period of performance of this study and the final publication of this report. For the convenience of the reader, some of the more salient recent contributions to understanding the frequency instability issue are summarized briefly below.

NERC submitted "Comments of the North American Electric Reliability Corporation Following September 23 Frequency Response Technical Conference" to FERC on October 14, 2010[116]. NERC stated that some of the reasons for frequency decline are:

- Larger governor dead band settings
- Steam turbine sliding pressure mode
- Loading generator units at 100 percent
- Blocked governor response
- Gas turbine inverse response
- Generators limited time of response
- Load frequency response change

NERC outlined a list of technical tasks associated with NERC's Frequency Responsive Initiative. The technical tasks include:

1. Collecting data and information from generator owners, generator operators, and balancing authorities
2. Developing clear terminology
3. Analyzing primary and secondary control response performance (current and historical)
4. Developing frequency performance metrics
5. Automating methods for indentifying frequency deviation events used to measure primary control
6. Developing methods for automatically collecting and analyzing frequency response and frequency control events
7. Analyzing appropriate frequency response and control to maintain system reliability
8. Determining an appropriate bias setting for use in AGC

[116] *Comments of the North American Electric Reliability Corporation Following September 23 Frequency Response Technical Conference*, Docket Nos. RM06-16-010 and RM06-16-011 (October 14, 2010).

9. Improving generators' and other devices' primary response dynamic models
10. Developing generators' and other devices' mid-term primary response dynamic models
11. Determining what factors influence inertial response
12. Examining renewable resources and smart grid load primary frequency response
13. Analyzing change in inertial response if inertial generators are displaced with electronically decoupled resources

On October 25, 2010, NERC submitted to FERC a proposed schedule for developing a frequency response requirement. On December 16, 2010, FERC issued an Order accepting NERC's filing.[117]

The NERC Resources Subcommittee published a discussion draft of its Position Paper on Frequency on November 23, 2010. NERC Resources Subcommittee believes that the interconnections frequency response is adequate at this time. It proposes a standard that will allow each interconnection to withstand at least two emergency events (N-2) before activating Under Frequency Load Shedding. It suggests that Frequency Response and Bias standard should be defined such that it brings more frequency responsive resources. The Frequency Response and Bias standard should also be adjustable such that it can be modified as the industry learns more. The Subcommittee recommended field testing that will provide data for analysis and standard improvement. It also recommended encouraging Smart Grid technologies to provide frequency response services. The position paper was open for comment until February 1, 2011.

FERC published the report "Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation" on January 21, 2011. The report was open for comments until March 7, 2011[118]. The report lists a set of metrics and tools that include new wide-area information and processing capabilities to measure frequency response adequacy inside the interconnection. The leading metric is primary frequency response. Impacts of increased renewable generation, such as lower system inertia, displacement of primary frequency control, and increased requirements of secondary frequency control are analyzed in the report. In addition, dynamic simulations studies were conducted for the Western Interconnection, Texas Interconnection, and Eastern Interconnection. The main recommendations of the report are to better understand the interconnection and balancing authority requirements for frequency control, to schedule adequate primary and secondary frequency control reserves, to expand frequency control capabilities and to develop comprehensive planning and operating procedures.

FERC also published five supporting documents:

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[117] *Mandatory Reliability Standards for the Bulk-Power System*, 130 FERC¶ 61,212, at P 1 (December 16, 2010 Order).

[118] On February 18, 2011 FERC issued a notice for an extension of time for filing comments up to and including May 6, 2011 under AD11-8 *Frequency Response Metrics to Assess Requirements for Reliably Integrating Renewable Generation.*

- *Analysis of Wind Power and Load Data* – Illustrates new methods of wind and load data analysis. The methods should help to better characterize volatile wind power output and to establish correlation between wind power and load.
- *Dynamic Simulation Studies of the Frequency Response* – Analyzes the effects of three different levels of wind generation on frequency behavior following an emergency event, such as a sudden loss of a generator, in the Western, Texas, and Eastern Interconnections.
- *Frequency Control Performance Measurement and Requirements* – Describes the history of frequency control performance measurement and its future requirements.
- *Interconnection Frequency Performance* – Reviews frequency performance based on historical data collected by NERC, with a focus on frequency response following an emergency event, for the Western, Texas and Eastern Interconnections.
- *Power and Frequency Control* – Reviews frequency and power control principles and illustrates the role of primary and secondary control.

Exhibit No. IPL-11

Whitepaper on Integrating Short-term Stored Energy Resource into MISO Markets

Incorporating Short-term Stored Energy Resource into Midwest ISO Energy & Ancillary Service Market

Yonghong Chen, Marc Keyser, Matthew H. Tackett, Xingwang Ma

***Abstract* – The purpose of this paper is to analyze various approaches to incorporate short-term stored energy resources into the Midwest ISO co-optimized energy and ancillary service market. Based on the analysis, the best approach is to utilize short-term storage energy resources for regulating reserve with the real-time energy dispatch to be set in such a way that the maximum regulating reserve can be cleared. Results on a 5-bus system are used to illustrate the clearing and pricing on short-term stored energy resources with the proposed approach. Monte Carlo simulation on the 5-bus system is used to illustrate the AGC regulation deployment.**

***Index Terms* – Ancillary services, Co-optimization, Dispatch and scheduling, Locational marginal price, Market Clearing Price, Reserve, Stored energy resource.**

I. Introduction

As the Regional Transmission Operator (RTO) and Balancing Authority (BA), the Midwest ISO is responsible for reliably and economically procuring energy, regulating reserves and contingency reserves as well as utilizing AGC to meet NERC standards for Balancing Authorities. Under the Day Ahead (DA) energy and ancillary service market and the Reliability Assessment Commitment (RAC) [1][2], energy is co-optimized with regulating and contingency reserves in the SCUC and DA-SCED software on an hourly basis. Under the Real Time (RT) energy and ancillary service market [1][3], energy is co-optimized with regulating and contingency reserves in the RT-SCED software every 5 minutes.

In February 2007, the Federal Energy Regulatory Commission (FERC) issued Order No. 890 [4] to ensure participation of non-generation resources in ISO markets on a fair and equitable basis. When the Midwest ISO started its energy market in April 2005, the energy market tariff [7] allowed Demand Response Resource (DRR) to bid into the energy market. With the start of the energy and ancillary service market in January 2009, the tariff further separates DRR into two types to allow better participation in the energy and/or ancillary service markets [1]. The Midwest ISO also includes in its energy and ancillary service tariff the means for implementation of energy storage technologies into the market with a proposed starting date of June 2009. Since the beginning of 2009, the Midwest ISO has worked with stakeholders on the detailed design to incorporate short-term Stored Energy Resources (SERs) into the Midwest ISO market. It then submitted a proposed revision to allow short-term SER to participate in the regulating reserve market with a starting date of January 1, 2010. The revision was conditionally accepted by FERC in December 2009.

There are various types of energy storages, such as pumped storage generators, compressed air storage, batteries and flywheels [5]. One of the important characteristics of storage devices is the Discharge Time at Rated Power (DTRP) [6]. Devices with DTRP in the range of hours can be handled similar to pumped storage resources. Such resources can provide energy, contingency reserves and regulating reserves. Adequate unit commitment and economic dispatch algorithms are required to effectively utilize the limited storage in both the operation planning and dispatch stages. Devices with DTRP less than five minutes will be difficult to manage by the Midwest ISO market system with a real time dispatch interval of five minutes. The focus of this paper is on the so called short-term Stored Energy Resources (SER). This specific type of stored energy resources typically has DTRP less than an hour but greater than the real-time dispatch interval, so that it can be considered by RT-SCED.

The short-term SER has several unique characteristics that can benefit the energy and ancillary service markets. First of all, it is usually very fast-responsive and can provide significant value for regulation response in AGC. Pacific Northwest National Laboratory (PNNL) compared the performance of fast-responsive storage resources with conventional regulation resources like hydro, combustion turbines, steam turbines and combined-cycle units in the California ISO market [8]. The conclusion is that the faster responsive resource can help to reduce California ISO's regulation procurement by up to 40% on average. The second important benefit of short-term SER is that it can help reduce CO_2 emissions. In [9], KEMA reported on a study of Beacon Power's flywheel technology in PJM, California ISO and ISO New England. The conclusion is that the flywheel-based frequency regulation can be expected to produce significantly less CO_2 emissions for all three regions.

Because of these benefits, many RTOs have been working on integrating short-term storage resources into their market systems. New York ISO (NYISO) created a resource type

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***Disclaimer*: The views expressed in this paper are solely those of the authors and do not necessarily represent those of Midwest ISO.**

called "Limited Energy Stored Resources (LESR)". FERC approved NYISO's tariff filing on LESR in May 2009 [10]. ISO-New England and California ISO have developed pilot programs for this new technology to participate in their regulating reserve markets.

The purpose of this paper is to present the studies and analysis that led to the market design for incorporating short-term SERs into the Midwest ISO market. Special considerations of product qualification for short-term SERs in the Midwest ISO market are introduced in section II. The design is to best fit the resource's special characteristics to the market. Section III describes the real time dispatch on short-term SERs. Section IV introduces the treatment of short-term SERs in DA and RAC. Section V illustrates the relationship between real time clearing and AGC deployment on short-term SERs. Monte Carlo simulation is used to show this relationship under random ACE input.

II. Market Product Qualification and Market Clearing Price on Short-term SER

A. Market Product Qualification

The Midwest ISO energy and ancillary service market clears energy and operating reserves. Under Midwest ISO market, operating reserve consists of regulating reserve and contingency reserve. Regulating reserve is cleared for AGC deployment on 4-second basis. Contingency reserve consists of spinning reserve and supplemental reserve. They are cleared for responses under the event of system contingency. Overall the ancillary service market procures three types of reserve products – regulating reserve, spinning reserve and supplemental reserve. The qualification and deployment requirements of the three types of reserve products are defined in [1].

A Short-term SER can only provide a very limited amount of sustained energy before it needs to be charged. Hence it is not suited for the energy product. Based on the NERC ninety minutes Contingency Reserve Restoration Period requirement following contingency event [11], a short-term SER is not suited for contingency reserves either. Therefore, in the Midwest ISO tariff, the short-term SER is only allowed to provide regulating reserves. In the Midwest ISO market design, regulating reserve is a higher quality product than contingency reserves and it can substitute for contingency reserves. To prevent regulating reserves cleared from short-term SERs to substitute for contingency reserves, a constraint is added to ensure that the total amount of regulation cleared on short-term SERs is no more than the system-wide regulating reserve requirement. This constraint will have implications on the regulating reserve Market Clearing Price (MCP) for short-term SERs.

The Midwest ISO also enforces zonal reserve constraints. Within each zone, regulating reserve can substitute for contingency reserve. Zonal contingency reserve requirements come from deliverability studies. The purpose is to ensure enough contingency reserves inside the zone so that the amount of contingency deployment imported from outside the zone will not cause transmission congestion. If short-term SERs are allowed to meet zonal regulating reserve requirements, they can potentially be used to substitute for zonal contingency reserves. After a short time period, likely to be less than the disturbance recovery period, the storage will deplete, and the zone will need additional import from outside to replace the deployment from short-term SERs. For this reason, short-term SERs are not allowed to meet zonal regulating reserve requirements.

B. Optimization constraints and MCP

Without short-term SERs, the DA and RT SCED optimization problem for the solution interval t can be described as follows [2][3]:

Minimize {EnergyCost(t) + RegulatingReserveCost(t) + ContingencyReserveCost(t) - ClearedReserveDemands(t) + PenaltyTerms}

Subject to:

System wide or zonal constraints (shadow price):

Power Balance Equation with losses (1.1)

Transmission Constraints (1.2)

System wide regulating reserve requirement ($\gamma_{MRR}(t)$) (1.3)

System wide regulating plus spinning reserve requirement ($\gamma_{MSR}(t)$) (1.4)

System wide operating reserve requirement ($\gamma_{MOR}(t)$) (1.5)

System wide generation based operating reserve constraint ($\gamma_{MGOR}(t)$) (1.6)

Zonal regulating reserve requirement ($\gamma_{ZRR}(z,t)$) (1.7)

Zonal regulating plus spinning reserve requirement ($\gamma_{ZSR}(z,t)$) (1.8)

Zonal operating reserve requirement ($\gamma_{ZOR}(z,t)$) (1.9)

Resource level constraints:

Limit constraints

Ramp constraints

Other constraints

Where

z: index for reserve zone

For resources other than short-term SERs, constraints (1.3)~(1.9) ensure that regulating reserve can substitute for contingency reserve and spinning reserve can substitute for supplemental reserve. Hence regulating reserve is a higher quality product than spinning reserve and spinning reserve is a higher quality product than supplemental reserve. Resources other than short-term SERs are all assigned to one of the reserve zones. Reserves cleared on those resources take the corresponding zonal MCP.

- The definition for zonal generation-based regulating reserve MCP is:

$$ZGenRegMCP(z,t) = \gamma_{MRR}(t) + \gamma_{MSR}(t) + \gamma_{MOR}(t) + \gamma_{MGOR}(t) + \gamma_{ZRR}(z,t) + \gamma_{ZSR}(z,t) + \gamma_{ZOR}(z,t) \quad (2.1)$$

- The definition for zonal generation-based spinning reserve MCP is:

$$ZGenSpinMCP(z,t) = \gamma_{MSR}(t) + \gamma_{MOR}(t) + \gamma_{MGOR}(t) + \gamma_{ZSR}(z,t) + \gamma_{ZOR}(z,t) \quad (2.2)$$

- The definition for zonal generation-based supplemental reserve MCP is:

$$ZGenSuppMCP(z,t) = \gamma_{MOR}(t) + \gamma_{MGOR}(t) + \gamma_{ZOR}(z,t) \quad (2.3)$$

Since the shadow price for (1.3)~(1.9) are all non-negative, price-cascading will always occur; namely, a higher quality product will have a higher MCP than lower quality product(s), within each zone:

$ZGenRegMCP(z,t) \geq ZGenSpinMCP(z,t) \geq ZGenSuppMCP(z,t)$

By introducing the short-term SER, cleared regulating reserve on short-term SERs can meet requirements in constraints (1.3), (1.4), (1.5) and (1.6). To prevent short-term SERs from substituting for spinning or supplemental reserves, a new constraint called "system wide short-term SER regulating reserve constraint" is introduced to ensure that total cleared regulation on short-term SERs is no more than the system wide regulating reserve requirement:

$$\sum_s Cleared\ \mathrm{Re}\, g(s,t) \leq System\ \mathrm{Re}\, g\ \mathrm{Re}\, quirement(t) \qquad (3)$$

In (3), ClearedReg(ser,t) is the regulating reserve cleared on short-term SERs at interval t. SystemRegRequirement(t) is the system wide regulating reserve requirement at interval t. The shadow price for this constraint $\gamma_{MSERR}(t)$ is negative when the constraint is binding. The MCP for regulating reserve cleared on short-term SER is:

$$MSERRegMCP(t) = \gamma_{MRR}(t)+\gamma_{MSR}(t)+\gamma_{MOR}(t)+\gamma_{MGOR}(t)+\gamma_{MSERRR}(t) \qquad (4)$$

When zonal reserve constraints (1.7)~(1.9) and system wide short-term SER regulating reserve constraint (3) are not binding, short-term SERs and all the other generation-based resources have the same regulating reserve MCP. The regulating reserve MCP is no less than the spinning reserve MCP and the spinning reserve MCP is no less than the supplemental reserve MCP. Under system-wide regulating reserve scarcity, regulating reserve scarcity price will be reflected into MSERRegMCP(t). Under system-wide regulating plus spinning reserve scarcity or system-wide operating reserve scarcity, the corresponding scarcity prices will also be reflected into MSERRegMCP(t) as long as **not** all system wide regulating reserve requirement is served by short-term SERs, i.e. constraint (3) is not binding. The reason is that clearing more regulating reserve on short-term SERs can free up regulating reserve on other resources so that they can be used to substitute spinning reserve or supplemental reserves.

When zonal reserve constraints (1.7)~(1.9) are binding, the regulating reserve MCP for the binding zones will be higher than MSERRegMCP(t). The reason is that short-term SERs can not meet the zonal reserve requirement and more expensive reserves on other types of resources need to be cleared to meet zonal requirements.

When zonal reserve constraints (1.7)~(1.9) are not binding but the "system wide short-term SER regulating reserve constraint" (3) is binding, i.e. all system wide regulating reserve requirement is met by short-term SERs, MSERRegMCP(t) can be less than the spinning or supplemental reserve MCP. The reason is that the lower cost regulation from short-term SERs can not substitute for spinning or supplemental reserves. In this scenario, even if there is system-wide regulating plus spinning reserve or system-wide operating reserve scarcity, the scarcity prices will not be reflected into MSERRegMCP(t) because any more regulating reserve from short-term SERs can neither substitute for spinning or supplemental reserves nor help to free up regulating reserve on other resources to substitute for spinning or supplemental reserves.

C. *Examples*

For the 5-bus system shown in Fig. 1 in the Appendix, the input data for RT-SCED [3] is shown in Table 1:

- G1~G5 are all in zone 1, and there is only one zone.
- Assume all resources are on-line and qualified for regulating and spinning reserve.
- InitialMW is the initial MW for enforcing the 5-minute ramp constraint.
- In the RT-SCED algorithm, fix the SER energy dispatch at 0MW and allow the regulation to be cleared within its limit ranging from -75MW to 75MW based on the regulation offer price of $1/MW.

Table 1

		Offer			Limit (MW)				
Unit	Node	Energy ($/MWh)	Reg ($/MW)	CR ($/MW)	Min	Max	Ramp MW/Min	Zone	InitialMW
G1	1	14	1.9	4.62	0	110	10	1	110
G3	3	30	4.5	7	0	520	20	1	67
G4	4	31	4.65	10.23	0	200	10	1	70
G5	5	10	1.5	5.3	0	600	30	1	450
SER	5	N/A	1	N/A	-75	75	1000	N/A	0

Table 2

Load	670 MW	Regulation requirement	CR requirement
Solved Losses	34.92 MW	71 MW	81 MW
Unit	ClearedEnergy (MW)	ClearedReg (MW)	ClearedCR (MW)
G1	84.92	25.08	0
G3	0	0	36.92
G4	20	20	0
G5	600	0	0
SER	0	71	0
Total	**704.92**	**116.08**	**36.92**

Table 2 shows the solution from RT-SCED. In this special scenario, the regulation offer is cheaper than contingency reserve offers. Therefore more than the required 71MW of regulation is cleared to substitute for contingency reserve. Even though the regulation from the SER is the cheapest at $1/MW, it is only cleared up to the system wide regulating reserve requirement, 71MW. The shadow price $\gamma_{MOR}(t)=7$ and $\gamma_{MSERR}(t)= -6$. The MCP for the SER is $MSERRegMCP(t)=1$ and it is the price paid for the 71MW regulation cleared on SER. The MCPs for other resources are:

$ZGenRegMCP(1,t)=ZGenSpinMCP(1,t)=ZGenSuppMCP(1,t)=7$

The regulation cleared on G1 and G4 are used to substitute for contingency reserves. Therefore, the regulating reserve MCP on generation resources is the same as the spinning and supplemental reserve MCPs.

III. Real Time Dispatch

In the Midwest ISO real time market, energy is co-optimized with regulating reserve and contingency reserve in RT-SCED every 5 minutes [3]. Even though short-term SERs only provide regulating reserve, the energy dispatch is critical to the procurement of regulating reserve. This section introduces the physical parameters of short-term SERs and how their capacity limits are dynamically calculated for RT-

SCED. Three options that have been studied on the energy dispatch are analyzed, and option 3 is chosen.

A. *Physical parameters and capacity limit calculation*

A short-term SER "s" needs to provide the following physical parameters (t is the dispatch interval):

a) RegMax(s,t), RegMin(s,t): regulation maximum and minimum limits (in MW). RegMin can be negative;
b) BiRampRate(s,t): bi-directional ramp rate (in MW/Min);
c) MaxEnergyStorageLevel(s,t): the maximum energy storage level (in MWh);
d) MaxEnergyChargeRate: the maximum energy that the resource can be charged during a one-minute time period (in MWh/Min);
e) MaxEnergyDischargeRate: the maximum energy that the resource can be discharged during a one-minute time period (in MWh/Min);
f) EnergyStorageLossRate: energy lost during a one-minute time period, inherent to the system (in MWh/Min);
g) MaxFullChargeEnergyWithdrawalRate: used to model additional capability for withdrawal of energy by adding, for example, resistors (in MWh/Min).

In addition, the RT-SCED algorithm needs to know the energy storage level ICCPEnergyStorageLevel(s, t_0) and the MW output ICCPCurrentMW(s, t_0) at the time t_0 when the case starts to execute. These two are instantaneous real time measurements sent to the RTO via Inter-Control Center Communications Protocol (ICCP). ICCPCurrentMW(s, t_0) is used by state estimator to solve for the state estimation output SEMW(s, t_0).

The RT-SCED case which starts at t_0 solves for target time t= t_0+10. The case solves every 5 minutes. Between [t_0, t_0+5], the resource is expected to follow the dispatch from the previous RT-SCED solution. Assume the cleared energy and regulating reserve to be ClearedEnergy(s, t_0+5) and ClearedReg(s, t_0+5) respectively.

To solve for the ClearedEnergy(s, t_0+10) and ClearedReg(s, t_0+10), the maximum and minimum limit for the SER between [t_0+5, t_0+10] must be determined. The limits change with the storage level. There are three steps to calculate the limits:

1) Calculate the maximum and minimum possible MW output between [t_0, t_0+5] based on SEMW(s, t_0), ClearedEnergy(s, t_0+5) and ClearedReg(s, t_0+5). Assuming the SER follows RTO set points, the output should come from the energy dispatch and regulation deployment from AGC. The maximum and minimum output that the SER can reach at t_0+5 are:

$$\begin{aligned}HighestMW(s, t_0+5) = Min(&ClearedEnergy(s, t_0+5) \\ &+ SERRegDeployfactor*ClearedReg(s, t_0+5), \\ &SEMW(s, t_0) + 5*BiRampRate(s, t_0+5));\end{aligned}$$

$$\begin{aligned}LowestMW(s, t_0+5) = Max(&ClearedEnergy(s, t_0+5) \\ &- SERRegDeployfactor*ClearedReg(s, t_0+5), \\ &SEMW(s, t_0) - 5*BiRampRate(s, t_0+5));\end{aligned}$$

SERRegDeployfactor is a tuning parameter between 0 and 1 that estimates the regulation deployment between [t_0, t_0+5]. This parameter will be discussed in detail in section V.

2) Calculate the maximum and minimum possible energy storage level at t_0+5 based on ICCPEnergyStorageLevel(s, t_0) and assuming that the SER stays at LowestMW(s, t_0+5) and HighestMW(s, t_0+5), respectively, between [t_0, t_0+5].

$$\begin{aligned}&InitialEnergyStorageCeiling(s, t_0+5) = \\ &\quad min(MaxEnergyStorageLevel(s, t_0+10), \\ &\quad max(0, ICCPEnergyStorageLevel(s, t_0) - \\ &\quad 5*EnergyStorageLossRate(s, t_0+5) - 5*LowestMW(s, t_0+5)/60))\end{aligned}$$

$$\begin{aligned}&InitialEnergyStorageFloor(s, t_0+5) = \\ &\quad max(0, ICCPEnergyStorageLevel(s, t_0) - \\ &\quad 5*EnergyStorageLossRate(s, t_0+5) -5*HighestMW(s, t_0+5)/60)\end{aligned}$$

3) Calculate the maximum and minimum MW that the SER can sustainably output between [t_0+5, t_0+10] under the energy storage floor and ceiling calculated from 2). The maximum limit is also capped by physical parameters like maximum energy discharge rate and RegMax. Similarly the minimum limit is capped by maximum energy charge rate and RegMin.

$$\begin{aligned}&MaxLimit(s, t_0+10) = \\ &\quad min \{12*max(0, InitialEnergyStorageFloor(s, t_0+5)- \\ &\qquad 5*EnergyStorageLossRate(s, t_0+10))), \\ &\qquad MaxEnergyDischargeRate(s, t_0+10)*60, \\ &\qquad RegMax(s, t_0+10)\}\end{aligned}$$

$$\begin{aligned}&MinLimit(s, t_0+10) = \\ &\quad max\{-12*[MaxEnergyStorageLevel(s, t_0+10)+ \\ &\qquad 5*MaxFullChargeEnergyWithdrawRate(s, t_0+10) \\ &\qquad - InitialEnergyStorageCeiling(s, t_0+5) \\ &\qquad + 5*EnergyStorageLossRate(s, t_0+10))], \\ &\qquad - MaxEnergychargeRate(s, t_0+10)*60, \\ &\qquad RegMin(s, t_0+10)\}\end{aligned}$$

The MaxLimit(s, t_0+10) and MinLimit(s, t_0+10) are used as the limits for solving the target time t=t_0+10 energy dispatch and reserve procurement. Three options have been considered for handling the energy dispatch in RT-SCED.

B. *Real time energy dispatch options*

In all three options, assume no energy, spinning and supplemental reserve offers from the short-term SER. The short-term SER can only offer regulating reserve into the market.

Option 1: Co-optimize short-term SER's energy dispatch with regulating reserve procurement. In this option, both **ClearedEnergy(s, t_0+10)** and **ClearedReg(s, t_0+10)** are primal variables. Since there is no energy offer, only the regulating reserve cost from "s" is added into the objective. It essentially treats the SER energy cost as 0.

Since RT-SCED solves for one target time and does not look over future intervals, this option may not manage the storage well to maximize its benefit over longer periods of time. For example, if dispatching the energy up can help relieve a transmission constraint, the energy will be dispatched to the maximum level until the storage is empty in several intervals. After that, if the LMP is not low enough, the SER will not be charged. It can result in a large percentage of idling time for the short-term SER. Hence it may not best use the regulation capability from short-term SERs.

Option 2: Always preset short-term SER's energy dispatch at the position that maximizes the regulating reserves that can be cleared. It is similar to the approach used by NYISO [10]. It pre-calculates and fixes the SER energy dispatch halfway between the maximum and minimum limits:

$$ClearedEnergy(s, t_0+10) =$$
$$0.5 * [MaxLimit(s, t_0+10) + MinLimit(ser, t_0+10)]$$

ClearedEnergy(s, t_0+10) is added into the power balance equation, but it is not a primal variable. **ClearedReg(s, t_0+10)** is a primal variable and it can be cleared to the maximum amount supported by the storage level:

$$\boldsymbol{ClearedRegRes(s, t_0+10)} \leq min\{5 * BiRampRate(s, t_0+10), 0.5 * [MaxLimit(s, t_0+10) - MinLimit(s, t_0+10)]\}$$

The benefit of this approach is that the short-term SER can always be charged or discharged so that the maximum amount of regulation can be cleared. It makes the best use of the regulation capability of short-term SERs. However, since the energy dispatch is pre-fixed, it may cause reliability and economic issues. For example, the short-term SER can be charged when the price is extremely high. The high price can be caused by transmission congestion or even system shortages, in which case the SER energy dispatch may jeopardize reliable operation of the system. Under this scenario, manual procedures can be introduced to disable SERs from clearing energy. But it can introduce additional burdens on operations.

Option 3: Preset short-term SER's energy dispatch at the position such that the maximum amount of regulation can be cleared, and also allow the energy dispatch to be violated if needed. This option is evolved from option 2 and adds protection inside the optimization to the potential harm that the pre-fixed energy dispatch may cause. First, the desired energy dispatch is calculated:

$$DesiredSERMW(s, t_0+10) =$$
$$0.5 * [MaxLimit(s, t_0+10) + MinLimit(s, t_0+10)]$$

Then introduce a new primal variable **SEREnergySlack(s, t_0+10)** so that DesiredSERMW(s, t_0+10) can be moved to 0 if necessary. In the objective, add the term:

$$\boldsymbol{SEREnergySlack(s, t_0+10)} * SEREnergyPenalty$$

SEREnergyPenalty is the penalty for violating the constraint. It is set to the same value as the regulating reserve demand price. The outcome is that the short-term SER will not be charged or discharged when the marginal cost of the dispatch is more than the regulating reserve demand price.

The following set of "SER energy dispatch constraints" is added:

If DesiredSERMW(s, t_0+10) > 0 then
$ClearedEnergy(s, t_0+10) =$
$DesiredSERMW(s, t_0+10) - \boldsymbol{SEREnergySlack(s, t_0+10)}$
Else if DesiredSERMW (ser,t+10)<0 then
$ClearedEnergy(s, t_0+10) =$
$DesiredSERMW(s, t_0+10) + \boldsymbol{SEREnergySlack(s, t_0+10)}$
Endif (5.1)

And

$$0 \leq \boldsymbol{SEREnergySlack(s,t_0+10} \leq abs(DesiredSERMW(s, t_0+10)) \quad (5.2)$$

ClearedEnergy(s, t_0+10) is added into the power balance equation.

The following ramp and limit constraints are enforced for short-term SERs:

$$\boldsymbol{ClearedRegRes(s, t_0+10)} \leq min\{5 * BiRampRate(s, t_0+10), 0.5 * [MaxLimit(s, t_0+10) - MinLimit(s, t_0+10)]\} \quad (5.3)$$

$$ClearedEnergy(s, t_0+10) + \boldsymbol{ClearedRegRes(s, t_0+10)} \leq MaxLimit(s, t_0+10) \quad (5.4)$$

$$ClearedEnergy(s, t_0+10) - \boldsymbol{ClearedRegRes(s, t_0+10)} \geq MinLimit(s, t_0+10) \quad (5.5)$$

If in the RT-SCED solution **SEREnergySlack(s, t_0+10)** is greater than 0, then set:

$$DesiredSERMW(s, t_0+10) = ClearedEnergy(s, t_0+10) * (1-\varepsilon)$$

and re-solve (ε is a very small number).

C. Examples

Example 1: Comparison of three energy dispatch options

In this example, the 5-bus system in Fig. 1 is used to sequentially run 291 RT-SCED cases based on the load profile shown in Fig. 2. The load profile is scaled down based on one day of Midwest ISO's actual load. Assume line 4-5 has limit 200MW.

Assume the following physical parameters for the short-term SER:

- RegMin: -20MW
- RegMax: 20MW
- BiRampRate: 1000MW/Min
- MaxEnergyStorageLevel: 5MWh
- MaxEnergyChargeRate: 9999 MWh/Min
- MaxEnergyDischargeRate: 9999 MWh/Min
- EnergyStorageLossRate: 0
- MaxFullChargeEnergyWithdrawRate: 0

Table 3 shows offers and parameters of the other resources. InitialMW is the MW at the beginning of the first interval.

Table 3

		Offer			Limit (MW)				
Unit	Node	Energy ($/MWh)	Reg ($/MW)	CR ($/MW)	Min	Max	Ramp MW/Min	Zone	InitialMW
G1	1	18.00	8.10	5.94	20.00	110.00	5.00	1	50
G3	3	30.00	13.50	7.00	30.00	427.00	4.00	1	40
G4	4	31.00	13.95	10.23	25.00	126.00	8.00	1	30
G5	5	15.00	6.75	5.30	55.00	377.00	6.00	1	350
SER	5	N/A	1.00	N/A	≥-20	≤ 20	1000.00	N/A	0

Table 4 shows the comparison of results from the three options. The column "Objective" shows total objective values from the 291 cases under the scenarios of no SER and energy dispatch options 1, 2 and 3, respectively. It shows that option 2 and 3 reduce the total cost significantly. Option 3 has the lowest total objective cost.

The column "Total SER EnergyDispatch*LMP" shows the sum of energy dispatch multiplied by LMP for the SER. It shows the total profit from energy dispatch. Note it is not the value used for actual settlement; the actual energy settlement is based on hourly time-weighted average LMP as defined in [1]. Under option 1, the energy dispatch is part of the co-optimization. Therefore it has the highest sum of energy dispatch times LMP, and the total value is positive. Under option 2, the energy dispatch is prefixed and can not be violated. The dispatch can easily be against the LMP. Hence it has the lowest value in this column and the value is negative.

Under option 3, the pre-calculated energy dispatch can be violated if needed. Therefore the value in the column under option 3 is higher than the one under option 2. But it is also a negative value due to the fact that the energy dispatch is independent of the optimization.

The column “Total SER ClearedReg*MCP” shows the sum of regulation procurement multiplied by regulating reserve MCP for the SER. It shows the total profit from regulation procurement. Again the value is not the one used for settlement. The actual reserve settlement is based on time and quantity weighted average MCPs as defined in [1]. The column “Total SER EnergyDispatch*LMP +ClearedReg*MCP” is the sum of “Total SER EnergyDispatch *LMP” and “Total SER ClearedReg*MCP”. The column “Percent of idling time” shows the percentage out of the 291 cases that there is nothing cleared on SER.

Table 4

	Objective	Objective delta to "No SER"	Total SER EnergyDispatch* LMP	Total SER ClearedReg* MCP	Total SER EnergyDispatch*LMP +ClearedReg*MCP	Percent of idling time
No SER	-$64,326,091					
Option 1	-$64,332,026	-$5,935	$5,666	$6	$5,671	97.94%
Option 2	-$64,372,291	-$46,201	-$8,373	$40,895	$32,523	0.00%
Option 3	-$64,374,869	-$48,778	-$5,553	$40,653	$35,100	0.00%

Under option 1, energy is part of the RT-SCED optimization. However RT-SCED only optimizes for one target interval. It can dispatch energy to empty or fill all the storage for relieving transmission constraints. If the price does not change signs, the SER will not be charged or discharged to be able to clear any products. The result in Table 4 shows that the SER is idle 97.94% of the time under option 1. This results in the lowest regulation profit as well as the lowest total profit from energy and regulation. Under both options 2 and 3, the short-term SER is charged or discharged constantly. There is no idle time. Under option 2, the energy dispatch is always at the point where the maximum regulation can be cleared. Therefore it has the highest regulation profit. However, since there is no protection for the energy dispatch to be against the price, the total profit from energy and regulation is not as high as the value under option 3.

Overall, option 3 produces the lowest objective cost to the system and the highest benefit to the short-term SER. It best uses the regulation capability of short-term SERs. Therefore it is chosen to be the energy dispatch approach inside RT-SCED. In this option, the desired energy dispatch for short-term SER is set at the point where the maximum regulation can be cleared. However, the desired energy dispatch can be violated if needed. Short-term SER can not submit energy offer to set LMP.

Example 2: Energy dispatch under option 3

This example shows the energy dispatch under option 3 for various conditions. In the 5-bus system in Fig. 1, assume there are only two generators, G1 and G4, available. Both G1 and G4 are qualified for spinning reserve and only G1 is qualified for regulating reserve. In this example, assume no transmission constraints and no losses. Also assume the load is at 245MW in the previous solutions. Table 5 shows the offers, parameters and initial MW.

Table 5

		Offer			Limit (MW)				
Unit	Node	Energy ($/MWh)	Reg ($/MW)	CR ($/MW)	Min	Max	Ramp MW/Min	Zone	InitialMW
G1	1	180.00	3.00	2.00	10.00	110.00	4.00	1	70
G4	4	30.00	N/A	1.00	17.00	175.00	8.00	1	175
SER	5	N/A	1.00	N/A	-20	0	100.00	N/A	0
								Total	245

Assume the regulating reserve requirement is 15MW and contingency reserve requirement is 30MW. Assume there is an empty storage SER with -20MW MinLimit. Under option 3, the DesiredSERMW is -10MW. SEREnergyPenalty is set at $170.

- First, assume the target interval load is 210 MW. With 4MW/Min ramp rate, expensive unit G1 is moved down 20MW. The cleared energy dispatch is 50MW. When there is no SER, cleared energy dispatch for unit G4 is 160MW. G4 is marginal for energy and LMP is $31/MWh. With the empty storage SER under -10MW DesiredSERMW, there is enough capacity from cheap unit G4 to charge SER. SER energy MW is cleared at -10MW and LMP stays at $31/MWh (Table 6).
- Next, assume the target interval load is 230MW. Under no SER, energy dispatch for unit G4 is at MaxLimit, 175MW. Energy dispatch for unit G1 is cleared at 55MW. G1 is marginal for energy and LMP is at $180/MWh. By introducing the empty storage SER with -10MW DesiredSERMW, the cost for charging the SER with unit G1 is more than SEREnergyPenalty $170. Hence SEREnergySlack is solved at 10MW and SER energy MW is cleared at 0 (Table 7). The result shows that the SER is not charged when the cost for charging is more than the violation penalty under option 3.
- Finally, assume the target interval load is 218MW. The expensive unit G1 is moved down 20MW. The cleared energy dispatch is 50MW. Under no SER, cleared energy dispatch for unit G4 is 168MW (7MW away from MaxLimit). G4 is marginal for energy and LMP is at $31/MWh. Introducing an empty storage SER with -10MW DesiredSERMW, the cost for charging the SER with unit G1 is more than SEREnergyPenalty. SEREnergySlack is solved at 3MW and SER energy MW is cleared at 7MW. RT-SCED will set DesiredSEMW at a value around -6.99MW and re-solve. The cleared energy dispatch for the SER is then -6.99MW and LMP stays at $31 (Table 8). The result shows that the SER is only charged to an amount such that the marginal cost for charging is less than the violation penalty.

Table 6

No SER								
Unit	ClearedEnergy	ClearedReg	ClearedCR	MinLimit (MW)	MaxLimit (MW)	LMP	RegMCP	Spin and Supp MCP
G1	50.00	15.00	15.00	10.00	110.00	31.00	3.00	2.00
G4	160.00	0.00	15.00	17.00	175.00	31.00	3.00	2.00
	210.00	15.00	30.00					
With SER under no storage								
Unit	ClearedEnergy	ClearedReg	ClearedCR	MinLimit (MW)	MaxLimit (MW)	LMP	RegMCP	Spin and Supp MCP
G1	50.00	5.00	25.00	10.00	110.00	31.00	3.00	2.00
G4	170.00	0.00	5.00	17.00	175.00	31.00	3.00	2.00
SER	-10.00	10.00	0.00	-20.00	0.00	31.00	3.00	2.00
	210.00	15.00	30.00					
			DesiredSERMW		-10			
			SEREnergySlack		0			

Table 7

No SER								
Unit	ClearedEnergy	ClearedReg	ClearedCR	MinLimit (MW)	MaxLimit (MW)	LMP	RegMCP	Spin and Supp MCP
G1	55.00	15.00	30.00	10.00	110.00	180.00	3.00	2.00
G4	175.00	0.00	0.00	17.00	175.00	180.00	3.00	2.00
	230.00	15.00	30.00					
With SER under no storage								
Unit	ClearedEnergy	ClearedReg	ClearedCR	MinLimit (MW)	MaxLimit (MW)	LMP	RegMCP	Spin and Supp MCP
G1	55.00	15.00	30.00	10.00	110.00	180.00	3.00	2.00
G4	175.00	0.00	0.00	17.00	175.00	180.00	3.00	2.00
SER	0.00	0.00	0.00	-20.00	0.00	180.00	3.00	2.00
	230.00	15.00	30.00					
			DesiredSERMW		-10			
			SEREnergySlack		10			

Table 8

No SER								
Unit	ClearedEnergy	ClearedReg	ClearedCR	MinLimit (MW)	MaxLimit (MW)	LMP	RegMCP	Spin and Supp MCP
G1	50.00	15.00	23.00	10.00	110.00	31.00	3.00	2.00
G4	168.00	0.00	7.00	17.00	175.00	31.00	3.00	2.00
	218.00	15.00	30.00					
With SER under no storage								
Unit	ClearedEnergy	ClearedReg	ClearedCR	MinLimit (MW)	MaxLimit (MW)			
G1	50.00	8.00	30.00	10.00	110.00			
G4	175.00	0.00	0.00	17.00	175.00			
SER	-7.00	7.00	0.00	-20.00	0.00			
	218.00	15.00	30.00					
			DesiredSERMW		-10			
			SEREnergySlack		3			
Unit	ClearedEnergy	ClearedReg	ClearedCR	MinLimit (MW)	MaxLimit (MW)	LMP	RegMCP	Spin and Supp MCP
G1	50.00	8.01	29.99	10.00	110.00	31.00	3.00	2.00
G4	174.99	0.00	0.01	17.00	175.00	31.00	3.00	2.00
SER	-6.99	6.99	0.00	-20.00	0.00	31.00	3.00	2.00
	218.00	15.00	30.00					
			DesiredSERMW		-6.99			
			SEREnergySlack		0			

IV. Day Ahead and Reliability Assessment Commitment Dispatch

Day Ahead (DA) and Reliability Assessment Commitment (RAC) are based on hourly intervals; as such, it is not possible to capture the storage dynamics for short-term SER. Under RT-SCED, the energy dispatch is placed at half the difference between MaxLimt and MinLimit, to clear the maximum amount of regulating reserve. The average energy dispatch over time should be around zero. Therefore in DA and RAC, the energy dispatch for short-term SER is set at 0 for every hourly interval.

Under Midwest ISO market, RAC process are conducted with energy and reserve co-optimized SCUC model [1][2] to ensure that sufficient resources will be available and on-line to meet load, operating reserve, and other demand requirements in the operating day. It is important to properly account for the regulating reserve from short-term SERs in RAC so that other resources are not over or under committed for providing regulating reserve.

Denote **ClearedReg(s, h)** as the regulating reserve cleared on short-term SER "s" during hour "h". It is a primal variable and the clearing cost is added into the objective. The following constraint is added to ensure the amount of procured regulating reserve is within physical limits:

$$\textbf{ClearedReg(s,h)} \le max(0,\ min\{60*MaxChargingRate(s, h),\ 60*MaxDischargingRate(s, h),\ 5*BiRampRate(s, h),\ RegMax(s, h),\ -RegMin(s, h)\})$$

In RT-SCED, a short-term SER is not allowed to self schedule regulation because the amount of regulation available is changing from interval to interval. Similar to RT-SCED, RAC uses real time offer. Therefore self schedule is not allowed in RAC on short-term SER.

In DA market, short-term SER can self schedule regulation. If the total amount of self scheduled regulation from short-term SERs is more than the system regulating reserve requirement, all the self-scheduled regulation on short-term SERs will be cleared to respect the offer from participants. The extra self-scheduled regulation can provide operators the information on how much is available from self-scheduled short-term SERs beyond system requirement. Furthermore, the self-scheduled regulating reserve from short-term SERs is free as explained below. In this scenario:

- Constraint (1.3) will not bind because the cleared regulation is more than requirement.
- Constraint (3) will not be enforced.
- Since regulation cleared on short-term SERs can not substitute spinning reserve or supplemental reserve, only the constant value SystemRegRequirement(h) will be added onto the LHS of constraint (1.4)~(1.6) to represent the contribution from short-term SER.
- MSERRegMCP(h) will become 0.

V. AGC Deployment

In section III.A, there is a parameter SERRegDeployfactor, used in calculating HighestMW(s, t_0+5) and LowestMW(s, t_0+5). The reason for introducing this parameter is that when RT-SCED starts to solve for interval [t_0+5, t_0+10] at t_0, it doesn't know what the regulation deployment will be between [t_0, t_0+5]. When SERRegDeployfactor is inconsistent with the actual AGC deployment, it can introduce under- or over-procurement of regulation on the short-term SER for the interval [t_0+5, t_0+10].

When SERRegDeployfactor is set at 1, it will assume AGC deploys all regulation up during [t_0, t_0+5] when calculating HighestMW(s, t_0+5). The InitialEnergyStorageFloor(s, t_0+5) will be the lowest possible storage level at t_0+5. Hence the MaxLimit(s, t_0+10) will be the smallest possible. Similarly the MinLimit(s, t_0+10) will be the largest possible. This will result in the narrowest dispatch range and the most conservative dispatch. The regulation procurement from this setting will always have storage to support it. When AGC deploys regulation on the short-term SER, it will never conflict with the storage level. However, if in reality AGC deploys randomly up and down between [t_0, t_0+5], the amount of regulation may be under-procured.

On the other hand, when SERRegDeployfactor is set at 0, it will assume AGC deploys no regulation or deploys randomly up and down during [t_0, t_0+5] when calculating HighestMW(s, t_0+5). The InitialEnergyStorageFloor(s, t_0+5) will be the highest possible storage level at t_0+5. Hence the MaxLimit(s, t_0+10) will be the largest possible. Similarly the MinLimit(s, t_0+10) will be the smallest possible. This will result in the widest possible dispatch range and the least conservative dispatch. The regulation procurement from this setting may not always have storage to support it. This could happen when AGC deploys consistently in one direction during [t_0, t_0+5]. The storage will not be able to support the regulation deployment on the procured regulating reserve.

To study the relationship between RT-SCED clearing and the AGC deployment, the 5-bus tool is enhanced to include an interface between 5-minute RT-SCED solution and 4-second AGC deployment on the short-term SER. The following are the inputs to the AGC deployment block:

- Cleared SER regulating reserve and the corresponding SER energy dispatch from RT-SCED
- ACE profile

The AGC deployment block calculates the regulation deployment on the SER based on the ACE, and tracks the storage level change based on the set point on SER. The storage level is then fed back to RT-SCED as the ICCPEnergyStorageLevel for the next interval.

The Midwest ISO AGC deploys regulating reserve based on regulation priority groups. The priority group is set based on the ramp rate available after load following. Since the short-term SER usually has a very high ramp rate, it should be in the highest priority group. Define Max1stPriorityReg as the maximum regulation available on the highest group. In this study, a 400MW system wide regulation requirement and 5 priority groups are assumed. Each priority group will have 80MW of cleared regulation. Therefore Max1stPriorityReg is 80MW. When |ACE| is higher than Max1stPriorityReg, all the regulation in the first priority group will be deployed. Therefore all the regulation on SER will be deployed. When |ACE| is lower than 80MW, the amount of (|ACE|/ Max1stPriorityReg)*ClearedReg(s, t) will be deployed on the SER.

Midwest ISO's AGC system tracks the storage level versus the set point from energy dispatch and regulation deployment on SER. If the storage level can not support the deployment on SER, the regulation deployment on SER will be moved to other available regulation resources. This can happen when a SER is deployed to regulate up and the storage runs to empty or when a SER is deployed to regulate down and the storage runs to full. In the 5-bus AGC simulation, the storage level SEREnergyStorage(s, t) is calculated based on the set point every 4 seconds. At the end of the 5-minute interval, if SEREnergyStorage(s, t_0+5) is less than 0 or above MaxEnergyStorageLevel(s, t_0), a test score SERRegTestScore(s, t_0) is calculated to track the percentage of deployment not supported by the storage level:

If SEREnergyStorage(s, t_0+5) > MaxEnergyStorageLevel(s, t_0),

$$SERRegTestScore(s,t_0) = 2 - \frac{SEREnergyStorage(s,t_0+5)}{MaxEnergyStorage(s,t_0)}$$

And the energy storage is reset to MaxEnergyStorageLevel(s, t_0) as the input ICCPEnergyStorageLevel(s, t t_0+5) in RT-SCED for the next interval,

Elseif SEREnergyStorage(s, t_0+5)<0 ,

$$SERRegTestScore(s,t_0) = 1 - \frac{abs(SEREnergyStorage(s,t_0+5))}{MaxEnergyStorage(s,t_0)}$$

And reset energy storage to 0 as the input ICCPEnergyStorageLevel(s, t t_0+5) for the next RT-SCED interval,

Else

$$SERRegTestScore(s,t_0) = 1$$

And SEREnergyStorage(s, t_0+5) is used as the input ICCPEnergyStorageLevel(s, t t_0+5) for the next RT-SCED interval

End

A SERRegTestScore(s, t_0) less than one gives an indication of the frequency at which the cleared SER regulation capability can potentially be unachievable due to its energy storage capacity limitation.

A Monte Carlo simulation is developed to assume a normal distribution with mean and standard deviation based on the one-day ACE profile shown in Fig. 3. For the short-term SER with parameters in III.C example 1, Table 9 shows the results under SERRegDeployfactor equal to 0, 0.8 and 1.

Under SERRegDeployfactor=1, the SERRegTestScore is 100%. But the average cleared regulation is 12.23MW. It is 61% of the 20 MW capacity. Under SERRegDeployfactor=0, the SERRegTestScore is 95.16%. There are 4.84% of the times that the cleared regulation on SER can not be counted. If the ACE is in one direction for a long period of time, this number can be larger. The average cleared regulation is 15.79MW. It is 79% of the 20 MW capacity.

Table 9

SERReg Deployfactor	Average ClearedReg (MW)	Average DepolyedReg (MW)	Average |DeployedReg| (MW)	Average {|DeployedReg|/ ClearedReg} (%)	Average ClearedEnergy (MW)	Average SERRegTestScore (%)
0	15.79	-0.999	12.3	78.10%	-0.168	95.16%
0.8	12.88	-0.682	10.01	81.32%	-0.152	99.16%
1	12.23	-0.661	9.53	78.18%	-0.028	100%

In summary, SERRegDeployfactor can be set near zero if the AGC deployment tends to be in both directions for most of the intervals. This can result in more regulation cleared on short-term SERs. However, if the AGC deployment tends to be in one direction for longer periods of time, it is better to set SERRegDeployfactor near one so that the cleared regulation on short-terms SERs is available to be deployed. This can result in less regulation to be cleared on short-term SERs.

VI. Conclusion

This paper introduces the studies that led to the design incorporating short-term SERs into the Midwest ISO energy and ancillary service market. The physical characteristics of the short-term SER are best fit for providing regulating reserve. Special constraints are set to avoid regulating reserve cleared on short-term SER substituting for contingency reserves. Price implications are discussed. The paper then explains the handling of real time energy dynamics of short-term SERs. Short-term SERs can not submit energy offer to set LMP. Three energy dispatch options are discussed and the option to dispatch energy to allow maximum regulating reserve procurement is adopted. Constraints are implemented to avoid potential negative impacts from the energy dispatch. The implementation in DA and RAC is also discussed. Finally, the relationship between RT-SCED regulating procurement and AGC deployment is analyzed and Monte Carlo simulation results are presented to illustrate the relationship.

VII. Appendix

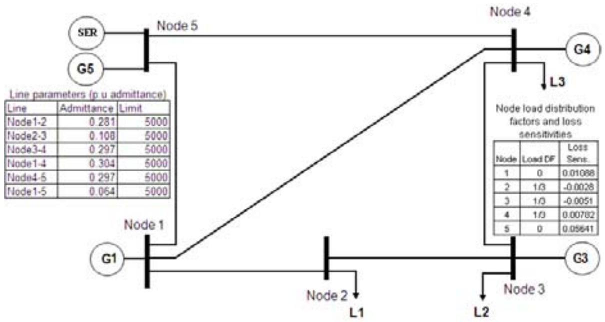

Fig. 1 5-Bus System

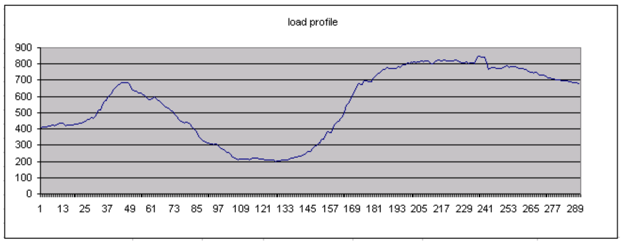

Fig. 2 Load profile

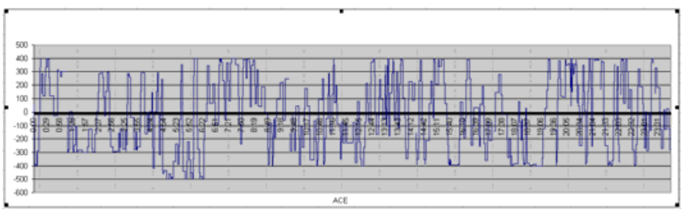

Fig. 3 ACE profile

VIII. Acknowledgment

The authors gratefully acknowledge the support from Todd Ramey, Kimberly Sperry, Joe Gardner and Paul Gribik from Midwest ISO, especially the review of the proposed formulations from Paul Gribik. The authors also appreciate the valuable discussions with Judith Judson and Todd Ryan from Beacon Power, and John Hickey from New York ISO.

IX. References

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X. Biographies

Yonghong Chen is currently a Consulting Market Engineer at Midwest ISO. In this role she is involved in market design, implementation and support. Before joining Midwest ISO in 2002, she worked with GridSouth Transco LLC from 2001 to 2002 and Nanjing Automation Research Institute from 1993 to 1998. She received her B.S. from Southeast University, Nanjing, China in 1990, her M.S. from Nanjing Automation Research Institute, China in 1993 and her Ph.D. from Washington State University, USA in 2001.

Marc Keyser is currently the Technical Lead – Market and AGC Engineering for the Midwest ISO. In this role he is involved in design, implementation, regulatory compliance and support of market and AGC systems. Before joining the Midwest ISO in 2007, he worked with Consumers Energy from 2002 to 2007. He received a B.S.E in Nuclear Engineering and a B.S.E in Engineering Physics from the University of Michigan in 2000, and his M.S.E. in Nuclear Engineering from the University of Michigan in 2001.

Matthew H. Tackett is currently Technical Manager - Transmission Infrastructure Strategies for Midwest ISO. Mr. Tackett led the market design effort for the Midwest ISO ancillary services market and has been with the Midwest ISO since 2003. Prior to being employed by the Midwest ISO, Mr. Tackett was employed by Dominion Virginia Power from 1986 to 1998, and was a consultant in the electric utility industry from 1998 to 2003. Mr. Tackett received a B. S. in Electrical Engineering from Purdue University in 1986 and is a registered professional engineer in Indiana and Virginia.

Xingwang Ma received his B.S. from Hefei University of Technology, China and his M.S. from the Graduate School, EPRI, China in 1983 and 1985 respectively. He worked with AREVA T&D from 1996 to 2006. He founded Electricity Market Consulting Inc providing independent consulting services on the design and implementation of electricity market and market operation systems.

Exhibit No. IPL-12

Excerpt from Market Settlements Presentation

Market Settlements

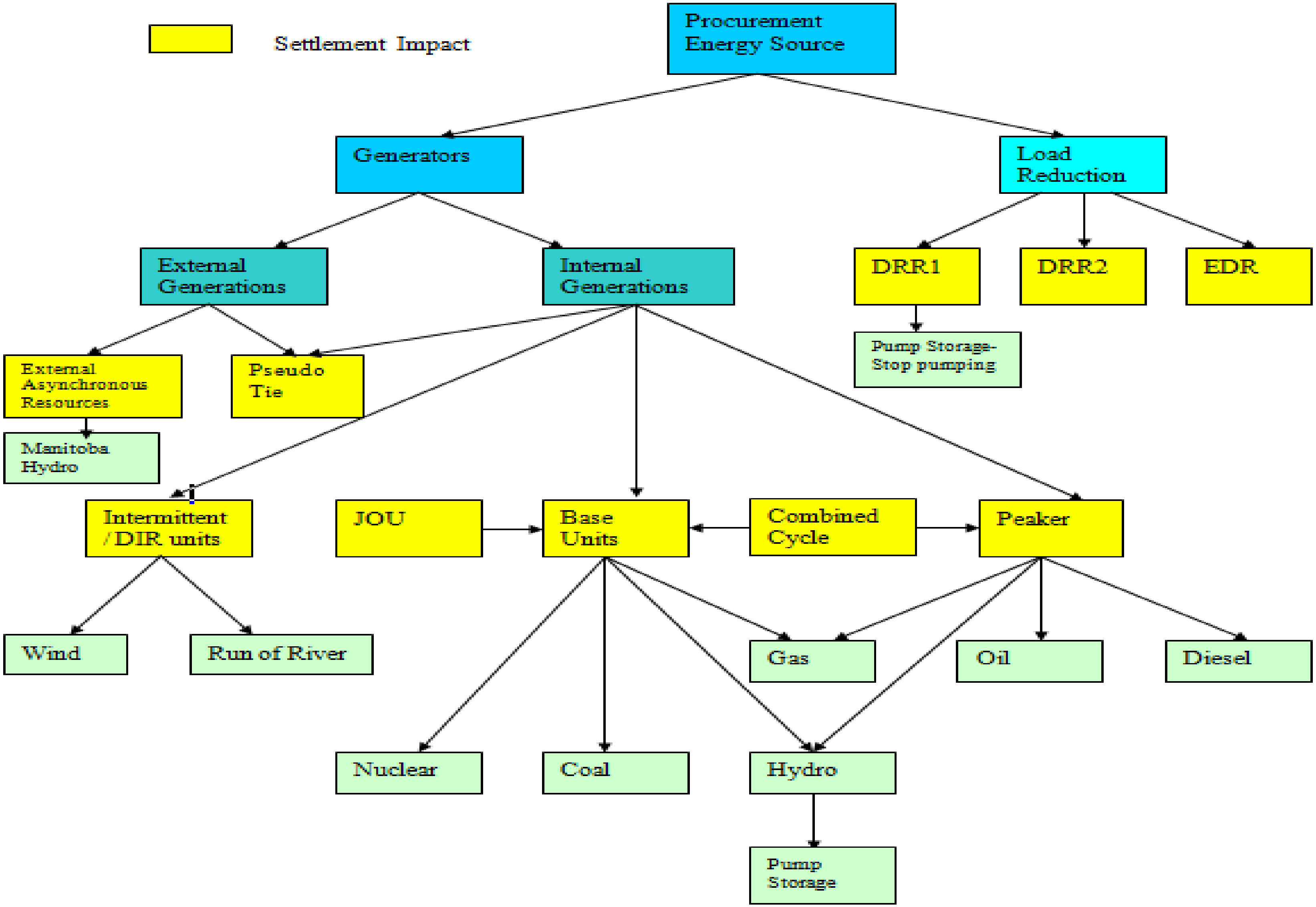
Generation Overview

Henry Chu

Sept 26, 2011

Generation Resources Overview

Generation Overview



Generator – Combined Cycle Resources

Combined Cycle Resources

- A Combined Cycle CT Generation Resource typically incorporates one or more gas-fired CTs, followed by heat recovery steam Generator(s) that use the exhaust heat from the CTs to generate steam, powering one or more steam turbine Generators.

- A Combined Cycle CT is normally offered as a single (aggregate) unit; however, the component CTs and/or steam turbine (ST) with an alternate steam or thermal source may be offered as separate units (for example, when the steam turbine unit or CTs are not in service).

Energy and Operating Reserve Markets Business Practices Manual BPM-002-r10 p4-78

MISO

Generator – Combined Cycle Resources

Combined Cycle Resources - Day-Ahead Market

- If an aggregate Offer exists for a Combined Cycle CT, then it is used; and any individual Offers for CTs that are components of the Combined Cycle CT are ignored;

- If an aggregate Offer for a Combined Cycle CT does not exist, individual CT or ST Offers are used;

- If the aggregate Offer is used for any hour in a day, the aggregate Offer's hourly values will be used for the entire day.

Energy and Operating Reserve Markets Business Practices Manual BPM-002-r10 p4-78

Generator – Combined Cycle Resources

Combined Cycle Resources – Real-Time Market

- If the Combined Cycle Resource was not committed in the Day-Ahead Energy and Operating Reserve Market or any RAC process (for both aggregate and single unit modeling), the MP may elect to change its Offer from aggregate to single unit or vice versa.
- Once the Resource is committed, no further changes are allowed for that Operating Day.

Energy and Operating Reserve Markets Business Practices Manual BPM-002-r10 p4-78

Generator – Combined Cycle Resources

Combined Cycle Resources – Settlements

- Settled at Aggregate or Individual offers depending on commitment ,
- Settled at Aggregate CPNode LMP,
- RSG Make Whole Payment is based on the Aggregate CPNode revenue.

Energy and Operating Reserve Markets Business Practices Manual BPM-002-r10 p4-78

Generator – Intermittent Resources

Intermittent Resources

- Not dispatchable;
- Must submitted Day-Ahead Forecast for its intended output; (No financial impact)

Generator – Intermittent Resources

Intermittent Resources –Day-Ahead Market

- Market Participant can submit economic offer the Day-Ahead Market,
- Can set Price

Energy and Operating Reserve Markets Business Practices Manual BPM-002-r10 Sec..2.9.10

Generator – Intermittent Resources

Intermittent Resources – Real-Time

- Exempted Excessive/Deficient Energy Deployment Charges
- Not eligible for RSG_MWP
- EEEF for all hours
- RT RSG Distribution Charges applies
- RT RSG Distribution Charges Exempt for Manual curtailment
- Price taker

Energy and Operating Reserve Markets Business Practices Manual BPM-002-r10 Sec..2.9.10

Generator – Dispatchable Intermittent Resources

Dispatchable Intermittent Resources (DIR)

- Types of DIRs – Wind, Solar, Run of River, and other variable energy;
- DIRs are not eligible to provide Operating Reserves;
- DIR can set price;
- DIR maximum limit is dependent on a forecast of their variable fuel source.

Generator – Dispatchable Intermittent Resources

DIRs can offer with the Commit Status in both DA and RT markets:

- Economic
- Emergency
- Must Run
- Outage
- Not Participating

Generator – Dispatchable Intermittent Resources

DIR – Settlements

- Eligible for cost recovery of operating costs for Economic Commitments in either Day-Ahead or Real-Time Markets RSG MWP
- Eligible for DAMAP (Day-Ahead Margin Assurance Payment)
- Eligible for RTORSGP (Real-Time Offer Revenue Sufficiency Guarantee Payment)
- Eligible for RSG DIST1
- RT Excessive or Non Excessive Energy Charge

Generator – Joint Operating Resources

Dynamically Schedule Joint Operating Resources(JOU) :

- Shared ownerships;
- Each shared plant owner must register its share as a separate unit;
- Offers for these JOUs are treated independently;
- MISO settles independently with each owner.

Generator – Pseudo Tie Resource

Pseudo-Tie Overview:

- All pseudo-tie units inside MISO must be registered and claimed by AO's;
- Pseudo-tie units are unavailable to participates in the Day-Ahead and Real-Time Markets;
- Pseudo-tie units needs a Financial Schedule to capture the Real-Time Congestion and Loss.

Generator – Pseudo Tie Resource

Pseudo-Tie Settlements

- State Estimator is used until Market Participant updates the Financial Schedule with actual meter data;
- Pseudo-tie units are transferred out of MISO and are responsible for Congestion, Loss and Admin charges in MISO.

Generator – Load Reduction Resource

Demand Reduction Resource (DRR) is a Load resource that is capable of supplying an amount of energy through physical Load interruption. Each DRR will have its own CPNode.

MISO

Generator – Load Reduction Resource

Demand Reduction Resource – Type I

- Capable of supplying a specific amount of Energy through physical Load interruption;
- A special DRR-Type I CPNode is created;
- Is an “On/Off” resource: provides 0 MW or Target Demand Reduction Amount
- Capable of providing Spinning or Supplemental Reserves
  – Not Capable of Providing Regulation Reserves

Generator – Load Reduction Resource

DRR– Type I Settlements

- DA and RT RSG MWP (Shut-Down, Hourly Curtailment and Energy Offers)
- RT_PV_MWP - DA MAP
- RT_DIST1

Generator – Load Reduction Resource

DRR – Type II

- Capable of supplying energy to the market through behind-the-meter generation or controllable load
- Can be committed and dispatched similar to generation resources
  - Capable of providing Regulation, Spinning, or Supplemental Reserves

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Generator – Load Reduction Resource

DRR – Type II Settlements

- DA_ASSET_EN
- DA and RT RSG MWP (Start-Up, No-Load, Energy and Operating Reserve Offers)
- RT_PV_MWP - RT ORGSP and DAMAP
- RT_RSG_DIST1 R
- RT_ASM_EXE_DFE_DEP
- RT_ASM_NXE or RT_ASM_EXE

Generator – Load Reduction Resource

Emergency Demand Response (EDR)

- EDR participants are able to make an offer to provide behind-the-meter generation(BTMG) or reduce load (DR) during defined system emergency conditions.
- EDR offers ($ and availability) can change daily.
- While the EDR offer is in-force, emergency response is required.
- Called upon during a NERC EEA2 event

Generator – Load Reduction Resource

EDR – Settlement

- Emergency Energy only
- Payment is *greater of:*
- LMP × Energy or
- Production Costs (Shut-Down costs + Curtailment offer × Energy)

Generator – Load Reduction Resource

EDR – Settlement

- Penalized if response<95% targeted amount
- If response<95%, EDR is not eligible for make-whole payment
- Shortfall defined as

  Targeted Amount × 95% - Actual Reduction
- Penalty = LMP_{RT} × shortfall

Questions ?

Exhibit No. IPL-13

PJM Manual 11: Energy & Ancillary Services Market Operations
Section 3: Overview of the PJM Regulation Market

pjm

Working to Perfect the Flow of Energy

PJM Manual 11:

Energy & Ancillary Services Market Operations

Revision: 84

Effective Date: August 25, 2016

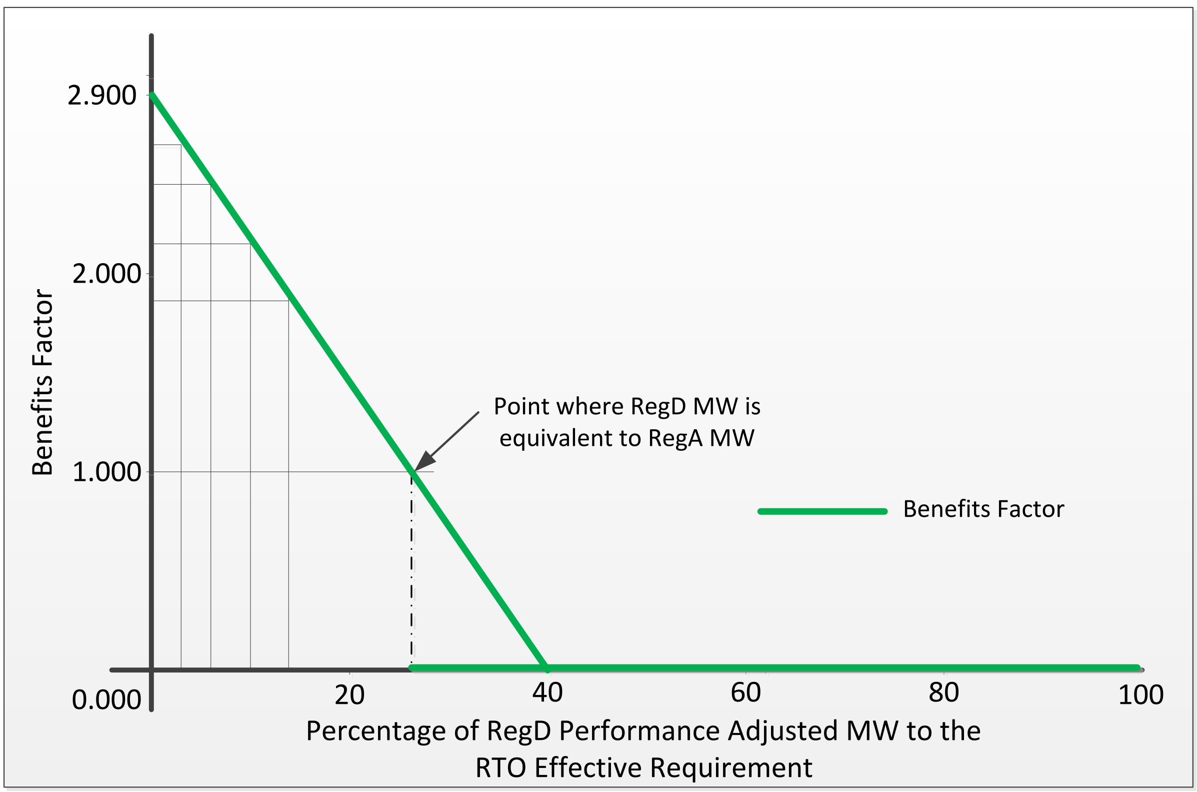
Prepared by

Forward Market Operations

Benefits Factor Function

Regulating resources can follow either a RegA (traditional) or RegD (dynamic) signal based on their resources' limitation and business practices. The regulating resources cleared in any hour can be any set of or mix of both traditional and dynamic resources. There is an operational relationship between the regulating resource mix and how the regulation requirement is satisfied. This relationship is included in the market clearing process as the Benefits Factor Function because the relationship is depicted as a curve.

The benefits factor translates a fast moving resource's MWs into traditional MWs or Effective MWs. These Effective MWs reflect the rate of substitution between resources following the different regulation signals. For market clearing, each dynamic resource will be assigned a decreasing and unique benefits factor. The benefits factor of the offered resource or resource specific benefits factor is the marginal point on the benefits factor function that aligns with the last MW, adjusted by historical performance, that specific resource will add to the dynamic resource stack.



The benefits factor ranges from 2.9 to 0 where a benefits factor of 1 is equivalent to a traditional resource. PJM will review the benefits factor as operational conditions warrant to re-evaluate the relationship when needed. These operational conditions could include, among other factors, changes to the regulation signal tuning parameters, changes in the set of resources providing regulation service, and changes to the regulation requirement.

PJM determines the benefits factor based on the expected impact that fast-following resources have on the NERC reliability criteria. Determination of expected response will be based a combination of off-line models, analysis of the regulation signals, and the historical operational data as it accumulates. Historical operational data will be given increasing weight to the benefits factor determination over time. Changes to the benefits factor function will be made periodically after review at the Operating Committee.

The net impact of the use of the benefits factor is to increase the likelihood of dynamic resources being selected in the clearing process, up to the point of diminishing returns. Beyond the point of diminishing returns (1 to 0), the benefits factor will decrease the likelihood of fast-following resources getting clearing.

During identified hours where more sustaining regulation (RegA) and less fast-following regulation (RegD) is warranted, RegD resources with a benefits factor less than 1 will not be considered in the regulation clearing because of its reduced benefits. A cap will be implemented at BF = 1 during these hours. Capped hours will be reviewed on a quarterly basis at the Operating Committee.

The benefits factor is calculated in ASO one hour ahead in real time for each qualified RegD resource participating in the Regulation Market. Also, the benefits factor is re-calculated for each RegD resource that is committed and providing regulation service in real-time for every 5 minute interval of the hour. The recalculation accounts for changes in the resource's adjusted total offer cost due to potential change in LMP at its bus which may affect its lost opportunity cost value. The benefits factor of RegA resources is always 1.

The benefits factor calculation steps include:

- Step 1: Calculation of the Performance Adjusted MW

$$Performance\ Adjusted\ MW = Capability\ (MW) * Historical\ Performance\ Score$$

- Step 2: Calculation of the Initial Adjusted Total Offer Cost

$$Initial\ Adjusted\ Total\ Offer\ Cost\ (\$) = \begin{pmatrix} Adjusted \\ Regulation \\ Capability \\ Cost \\ (\$) \end{pmatrix} + \begin{pmatrix} Adjusted \\ Lost \\ Opportunity \\ Cost \\ (\$) \end{pmatrix} + \begin{pmatrix} Adjusted \\ Performance \\ Cost \\ (\$) \end{pmatrix}$$

$$in\ this\ step, the\ resource\ benefits\ factor\ is\ assumed\ to\ be\ 1$$

RegD resources with initial adjusted total offer cost equal to zero will still be given priority in the ranking, but will instead be ordered using the resource specific historical performance score as a tie-breaker.

- Step 3: Calculation of the rolling performance adjusted MW based on the initial adjusted total cost in ascending rank order

- Step 4: Calculation of the resource specific benefits factor based on the defined benefits factor curve

Three Pivotal Supplier Test

PJM utilizes the Three Pivotal Supplier (TPS) Test in the regulation market to mitigate market power as detailed in section 3.2.2A.1 of the PJM Tariff. Each supplier, from 1 to n, is ranked from the largest to the smallest offered MW of eligible regulation supply adjusted by the resource-specific benefits factor and the resource specific performance score in each hour. Suppliers are then tested in order, starting with the three largest suppliers. In each iteration of the test, the two largest suppliers adjusted by the benefits factors of the offered resources and the resource specific performance scores are combined with a third supplier adjusted by the benefits factor of the offered resource and the resource specific performance score, and the resulting combined supply is subtracted from total effective supply adjusted by the benefits factors of all offered resource and their resource specific performance scores. The resulting net amount of eligible supply is divided by the regulation requirement for the hour adjusted by the resource-specific benefits factors and the resource specific performance scores (D). Where j defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with j=3). Equation 0-1 shows the formula for the residual supply index for three pivotal suppliers (RSI3):

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D}.$$

Where j=3, if RSI3j is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a supplier j result in RSI3j greater than 1.0. When the result of this process is that RSI3j is greater than 1.0, the remaining suppliers pass the test. Any resource owner that fails the TPS Test will be offer-capped.

- Regulating resources are offer-capped at the lesser of their cost-based or market-based regulation offer price.
- An offer-capped resource will only be offer-capped for a single hour at a time as the TPS Test is rerun for each hour of the day.
- Resource merit order price ($/MWh) = Resource regulation offer + estimated resource opportunity cost per MWh of capability adjusted by the resource-specific benefits factor and the resource specific performance score.

ATTACHMENT B

FORM OF NOTICE

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Indianapolis Power & Light Company	)	
Complainant,	)	
v.	)	**Docket No. EL17-___-000**
Midcontinent Independent System Operator, Inc.	)	
Respondent.	)	

NOTICE OF COMPLAINT
(October __, 2016)

Take notice that on October 21, 2016, Indianapolis Power & Light Company ("IPL") filed a formal complaint against the Midcontinent Independent System Operator, Inc. ("MISO") pursuant to Section 206 the Federal Power Act, 16 U.S.C. § 824e (2015) and 18 C.F.R. § 385.206 (2016), requesting that the Commission find that the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff is unjust and unreasonable, unduly discriminatory and preferential because it does not provide a means for IPL's Advancion® Energy Storage Array, a.k.a. the Harding Street Station Battery Energy Storage System ("HSS BESS") to be compensated for services it provides to the MISO system, including Primary Frequency Response.

IPL certifies that copies of the complaint were served on the contacts for MISO as listed on the Commission's list of Corporate Officials. Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answers and all interventions or protests must be filed on or before the comment date. The Respondent's answers, motions to intervene, and protests must be served on the Complainant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive e-mail notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please e-mail FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 p.m. Eastern Daylight Time on (insert date).

Kimberly D. Bose,
Secretary

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