Primary frequency control reserves are adequate, if, following a sudden largest loss of generation[1], the primary frequency control actions provided by these reserves successfully arrest and stabilize frequency decline prior to the dropping of firm customer loads through under-frequency load shedding. The most important aspect of frequency behavior following the sudden loss of generation is the point at which frequency is arrested or the frequency nadir. If frequency nadir is greater than (i.e., frequency is arrested above) the highest set point for under-frequency load shedding, then the primary frequency control reserves that were in place at the time generation was lost were adequate. If, however, frequency decline is not arrested and frequency crosses below the highest set point, firm customer loads will be dropped through the actions of under-frequency load shedding. This means the primary frequency control reserves that were in place were inadequate [LBNL report, 2010].

Frequency response is the traditional metric used to describe how an interconnection has performed in stabilizing frequency after the loss of generation. Frequency response is measured by relating the size of the generation lost to the resulting net change in system frequency once frequency has been stabilized (at Point B), see textbox below for NERC ALR1-12 metric.

One reason the traditional definition of frequency response is based on settling frequency (Point B) is that until recently power system monitoring technologies could not reliably measure frequency nadir (Point C). Frequency nadir could only be studied with simulation tools. Advances in power system monitoring technologies have now made it possible to measure frequency nadir in the field [LBNL report, 2010].

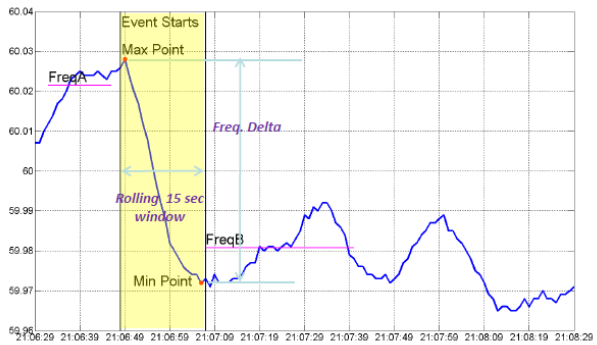
ALR1-12: This metric is used to track and monitor Interconnection's frequency response. It is defined as a sum of the change in demand plus the change in generation, divided by the change in frequency expressed in MW/0.1 Hz. The metric measures the average Frequency Response where frequency drops more than Interconnection's defined threshold (Table 9 below). High resolution frequency measurements (F-net and...) are used to produce frequency time series with 1-second resolution, which is used in ALR1-12 analysis.

While the calculations may show trends from year to year no attempts 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 basis for future root-cause analysis. (http://www.nerc.com/pa/RAPA/ri/Pages/InterconnectionFrequencyResponse.aspx)

Figure below shows the criteria for calculating average values A and B. The event starts at time t ±0. Value A is the average from t -16 to t -2 and Value B is the average from t +20 to t +52. The difference of value A and B is the change in frequency used for calculating Frequency Response. These lengths of time used to calculate these values accounts for the variability in System Control and Data Acquisition (SCADA) scan rates that vary from two to six seconds in the multiple-Balancing Authority interconnections.

Commented [MJ1]: Bob mentioned another high resolution data source that's used here?

[1] 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[NERC BAL-003-1]

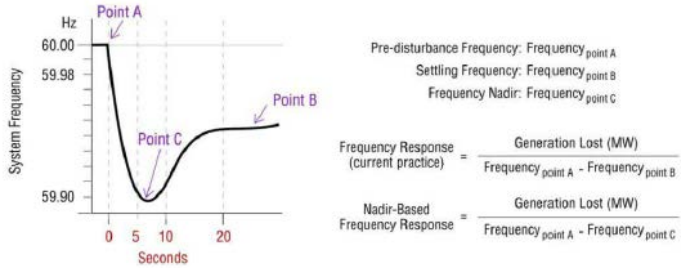


Value A (average t -16 to t - 2) & **Value B** (average t +20 to t + 52)

Table 9: Frequency Event Triggers			
Interconnection	ΔFrequency (mHz)	MW Loss Threshold	Rolling Windows (seconds)
Eastern	36	800	15
Western	70	700	15
ERCOT	90	450	15
Québec	140	450	15

We propose Measure 4 to enhance the traditional frequency response metric and focus on **all** aspects of frequency response that are important for reliability immediately following a loss-of-generation event which are:

1. **<u>A to C measure</u>** is calculated **nadir-based frequency response** in MW/0.1 Hz (unit loss divided by A to C frequency deviation) trended year to year versus system conditions (e.g. net load or system inertia or committed synch MW) .

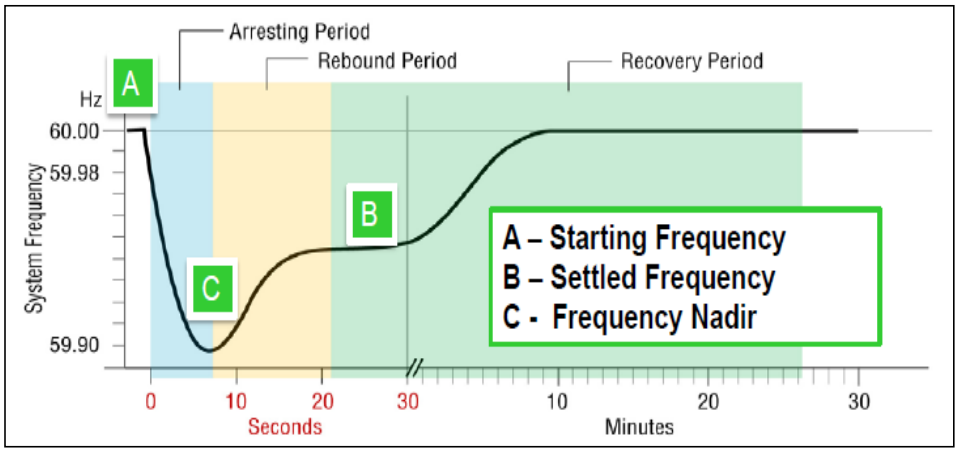


This measure captures the impacts of inertial response, load response (load damping) and partially governor response (governor response is deployed immediately after frequency falls

outside of a pre-set dead band, however, depending on generator technology, full governor response is deployed in about 12-16 seconds). Trending this measure year to year will capture effect of changes in generation mix and load characteristics and help to identify needs for fast power injection from e.g. battery storage, or load resources with under-frequency relays to provide fast frequency control and assist in arresting system frequency after large generation loss.

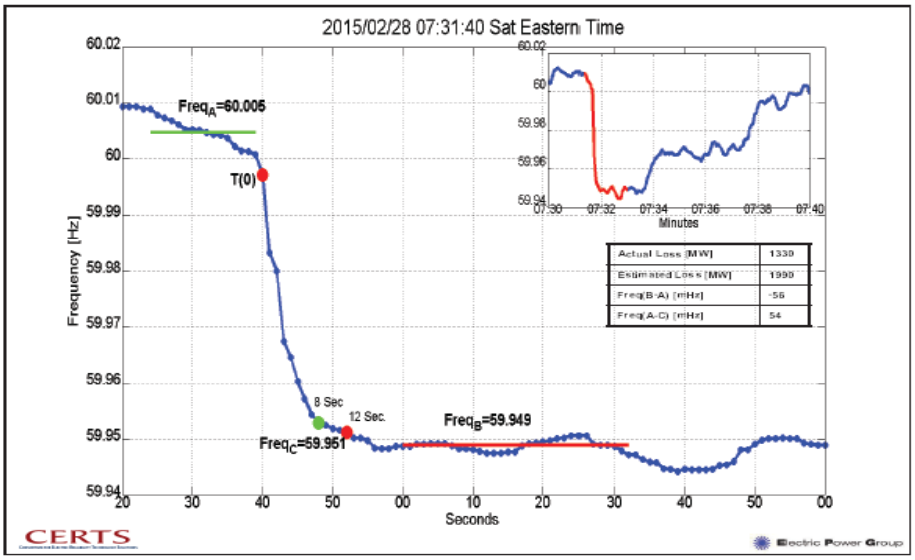
Commented [MJ2]: I know this is the time frame for ERCOT but not sure about other interconnects

2. **A to B measure** captures the speed and effectiveness of primary frequency response. Here ALR1-12 in MW/0.1 Hz could be trended year to year versus system conditions. ALR1-12 metric is already being used. However trending it vs time does not provide information on how at similar system conditions the response is changing year to year. So this would be an improvement that the group could recommend.
3. **B to C measure** this could be ratio on its own or in form of ratio between 1 and 2 above. This measure should also be trended year to year versus system conditions since B to C would be related to system inertia and speed of governor response of committed generators.
4. **C to C' measure** in Hz trended year to year versus system conditions. In Eastern Interconnect difference between Point C and Point C' (59-78 seconds after an event due to governor response withdrawal[2]). While ALR1-12 data does not contain C', original frequency data with 1-second resolution (captures 300 seconds of an event) can be used. In Eastern Interconnect, trending the difference between Point C and Point C' for similar size events will capture if generators are working with vendors to adjust plants DCS controllers and avoid governor response withdrawals[3].



[2] Point C' is observed in Eastern Interconnect after large generator trip. Few seconds after initial governor response from generating units, their active power set point control takes over bringing generation units back to their original operating point, which results in withdrawal of governor response and further frequency decrease as a result. Point C' may be lower than initial frequency nadir (Point C).

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



It should be pointed out that currently, there is no problem with frequency nadir in any of the 4 interconnections. We recommend this measure for the interconnects to be able to see the changes year to year and if there is a concern more detailed analysis will be needed to understand the reason behind declining trends.

ERCOT Example.

Below are two plots for ERCOT based on 2010-2014 event data. First plot shows frequency nadir for the whole year of events (the largest events were excluded since these being single event majorly affect the trend lines). From this figure the 2010-2011 nadirs are lower for the same event size the nadir is improving since, even though there is more wind generation installed each year (see Figure 3 below) and system inertia is getting lower during high wind low load conditions. The reason behind frequency nadir improvement are as follows:

- During transition from zonal to nodal extensive governor testing was done at all plants
- Since March 2012 wind generators are required to provide governor like response. This response is faster than governor response from conventional generators. Governor-like response from wind generators is available at overfrequency any time a generator is in operation and at underfrequency when a wind generator is curtailed. Until completion of CREZ transmission project (at the end of 2013) wind generation in West Texas was oftentimes curtailed and therefore capable of governor line response at underfrequency events.

- In January 2014 BAL-001-TRE standard was approved 1/16/2014 with effective date 4/1/2014 and implementation plan for 30 month, however during the development of the standard many generators tested their governors with more narrow governor deadband settings as prescribed by the standard and then did not change the settings back.

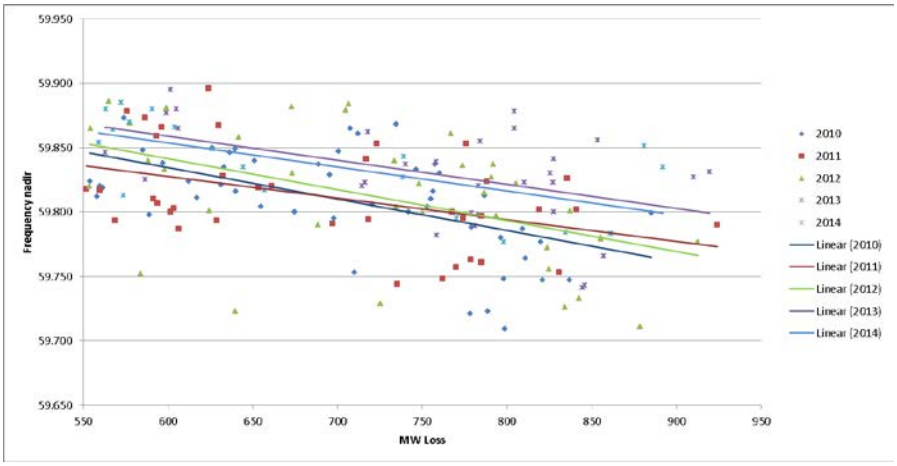


Figure 1: Frequency nadir (point C) in ERCOT 2010-2014.

The second plot shows **nadir-based frequency response** as a function of system net load (load minus wind).

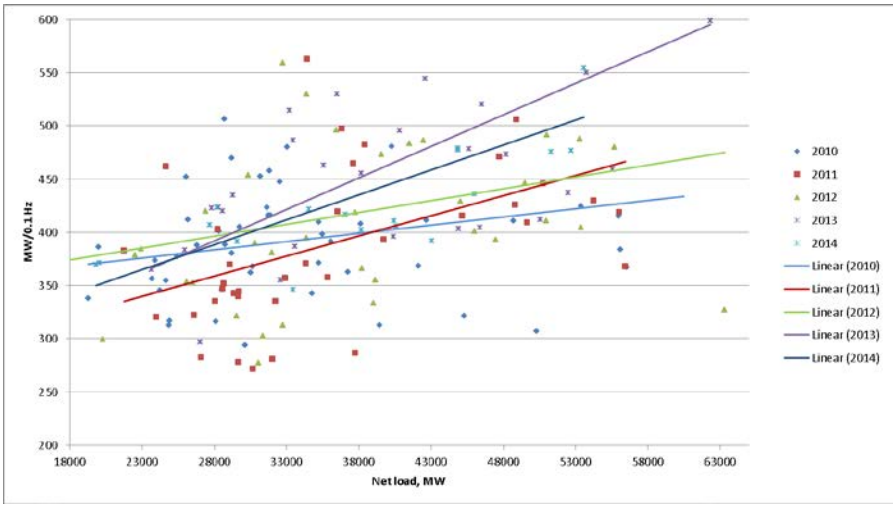


Figure 2: Frequency nadir expressed as MW/0.1 Hz in ERCOT 2010-2014.

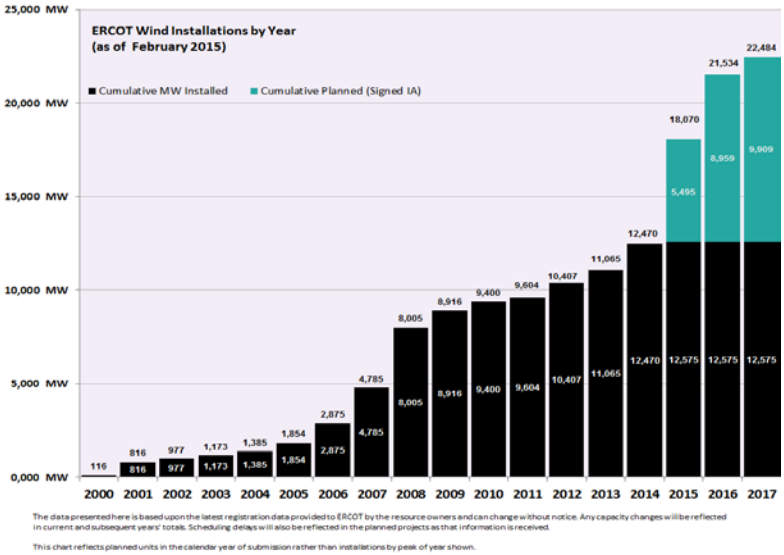


Figure 3: ERCOT Wind Generation Installations by year (as of February 2015)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

California ISO
Shaping a Renewed Future

ERSTF
Loads and Resources Balance

Clyde Loutan, Senior Advisor – Renewable Energy Integration, CAISO

MISO Eagan Office, Minnesota

May 11 & 12

RELIABILITY | ACCOUNTABILITY

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Measure 6 – Net Demand Ramping Variability

- Measure 6 outlines a methodology to evaluate the Net Demand upward and downward Ramping Variability
- 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 may elect to evaluate variability at different timeframes depending on its existing generation mix and/or scheduling timeline.
- Ultimately, the BA needs to have adequate resources available to meet the demand variability (i.e., the necessary ramping capability)

Recommendations

- Measure 6 should be measured at a BA level to ensure the BA has adequate ramping capability to address variability and uncertainty of VERs.
- Based on the experience within CAISO, BA's expecting an influx of grid connected Solar PV or distributed rooftop Solar PV can track net demand variability on an annual basis
- BAs should begin trending CPS1 excursions below 100% on shortened timeframes such as hourly or daily to identify any correlation between significant intra-hour or multi-hour ramps and CPS1.
- BAs should also begin tracking the frequency and duration of Balancing Authority ACE Limit (BAAL) exceedances and identify any correlation between these exceedances and insufficient ramping capability
- BAs should review their net inadvertent interchange to determine if ramping deficiencies within a BA results in inadvertent flows to neighboring entities
- Develop day-ahead and real-time forecasting tools to better predict VER spikes.

Observations

With high penetration levels of VERS there is a :

- Greater risk of over-generation during periods of low demand
- Need to mitigate steep intra-hour net demand ramps as well as mitigating multi-hour net-demand ramps
- Decrease in frequency response capability as more conventional resources are displaced.
- Need for more flexible resources with ramping capability with the capability to stop and start multiple times per day.
- Greater difficulty in accurately forecasting operating needs on the system.
- Potential for rapid change in the intra-hour ramp direction.

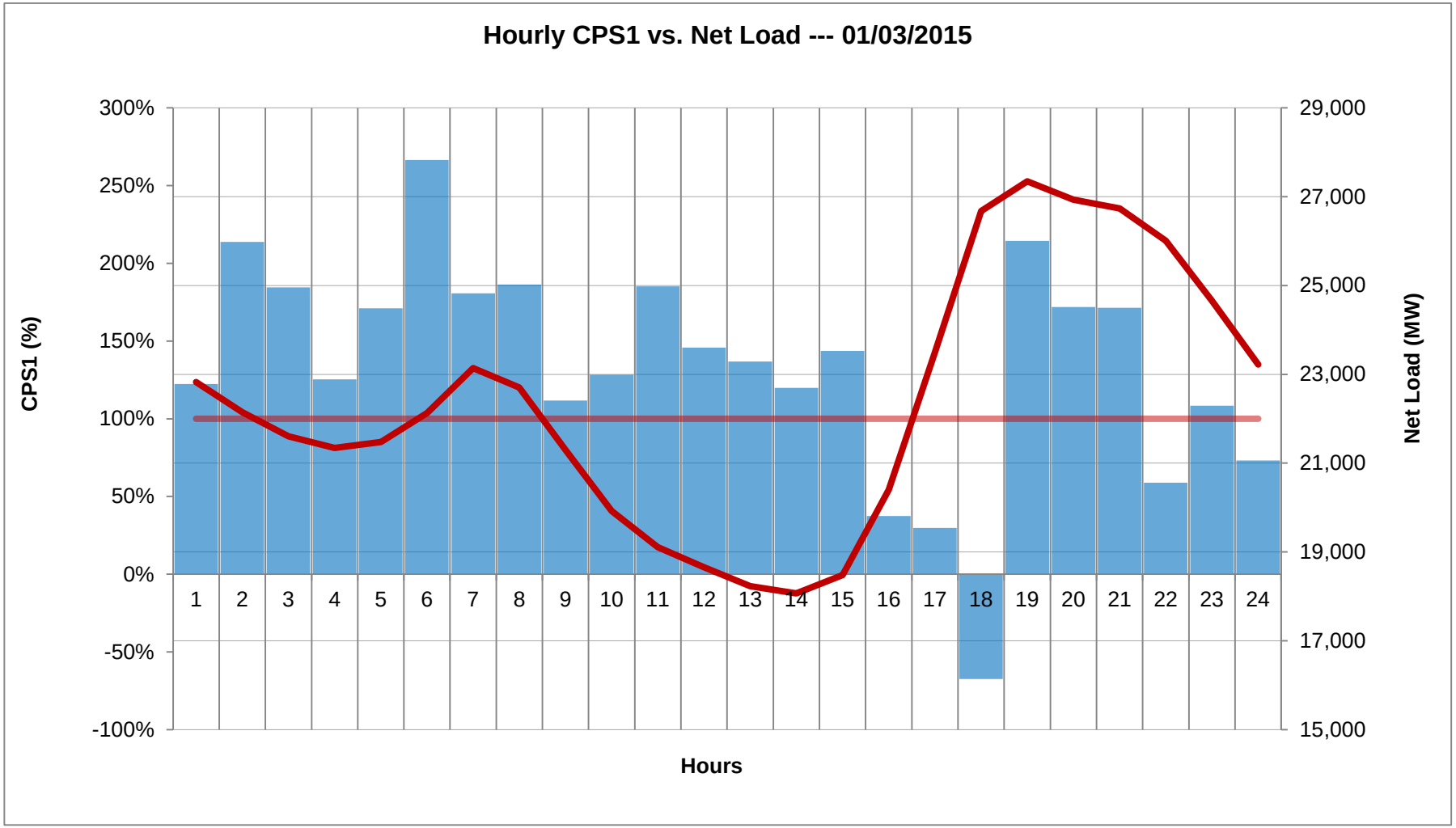
Summary of survey results

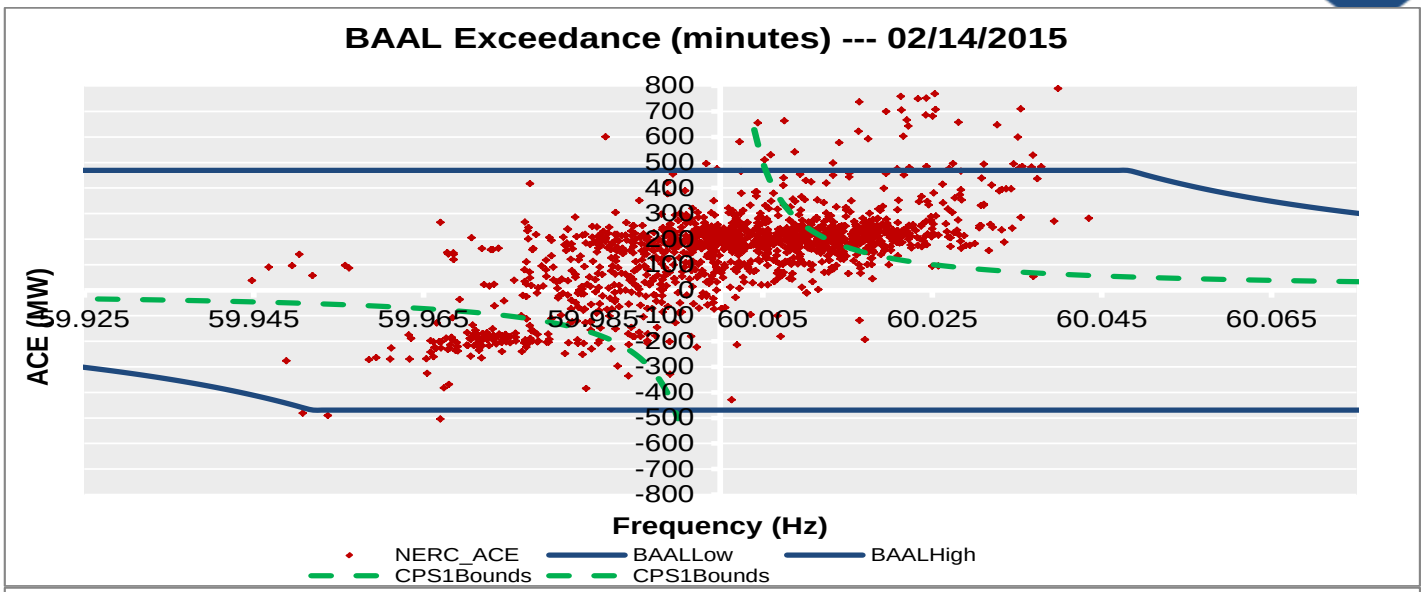
BA/ISO	Installed Capacity of Non-synchronous generation (NSG), 2014	Installed Capacity of NSG 2017	Flexible Capacity increasing?
CAISO	12,471	17,176	Yes
ERCOT	11,066	21,130	No
ISO NE	3,155*	5,591*	No
IESO	4,075*	5,607*	No
MISO	13,726	18,526	No
BC Hydro	487.2	667	No
Southern BA	454	2,324	No
Duke: DEF	0	0	No
Duke: DEC	136	232	No
Duke: DEP	320	712	No

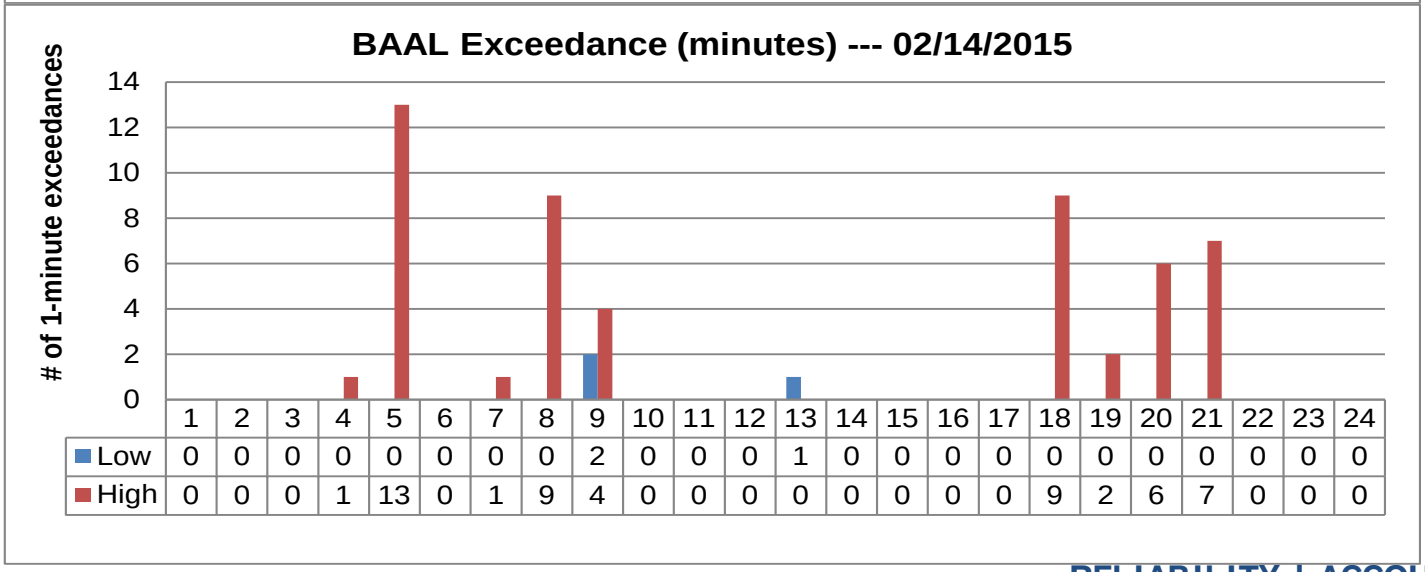
CAISO expected build-0ut between 2015 through 2018

Resource Type	Existing MW (2014)	2015 MW	2016 MW	2017 MW	2018 MW
ISO Solar PV	4,482	5,785	6,874	8,007	8,078
ISO Solar Thermal	1,214	1,214	1,200	1,130	1,095
ISO Wind	4,992	4,541	4,462	4,319	4,213
Incremental distributed PV		569	1,331	1,743	2,181
Total Variable Energy Resource Capacity in the 2014 Flexible Capacity Needs Assessment	10,687	12,110	13,867	15,198	15,567
Non ISO VER Resources firmed by external BAA	1,784	2,200	2,168	1,978	1,978
Total internal and external VERs	12,471	14,310	16,035	17,176	17,545
Incremental New Additions in Each Year		1,839	1,726	1,141	369

Hourly CPS1 vs. net load ramps

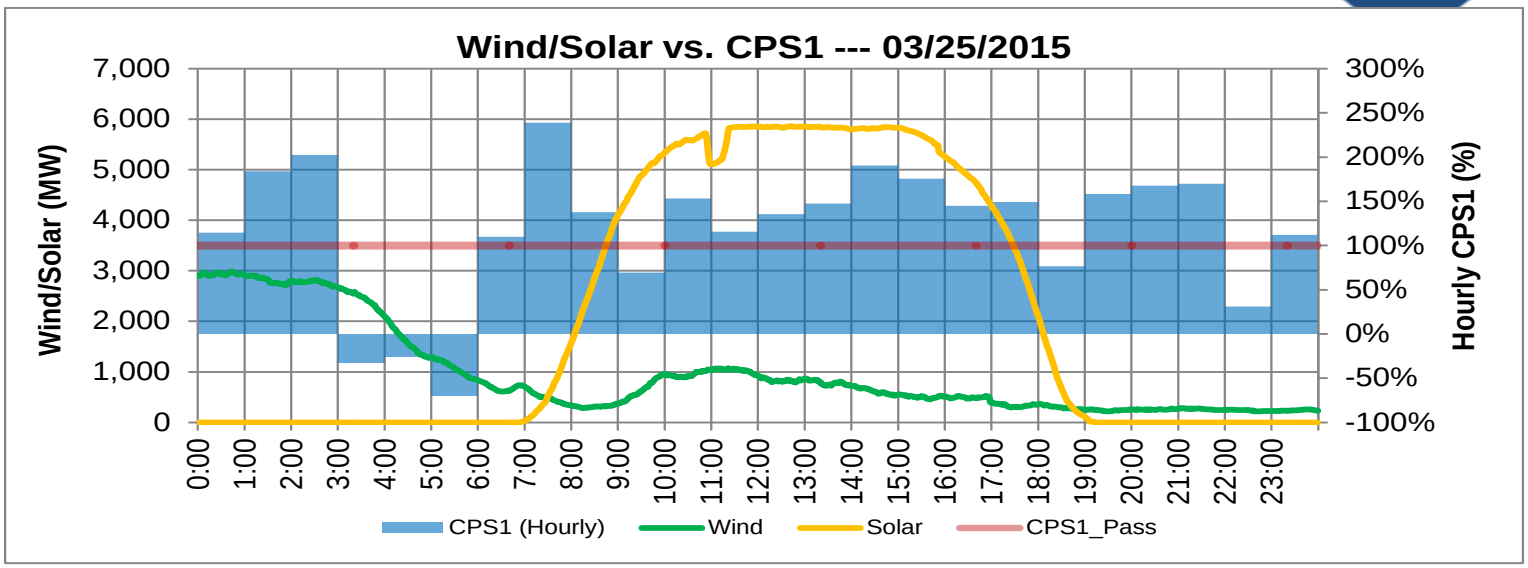


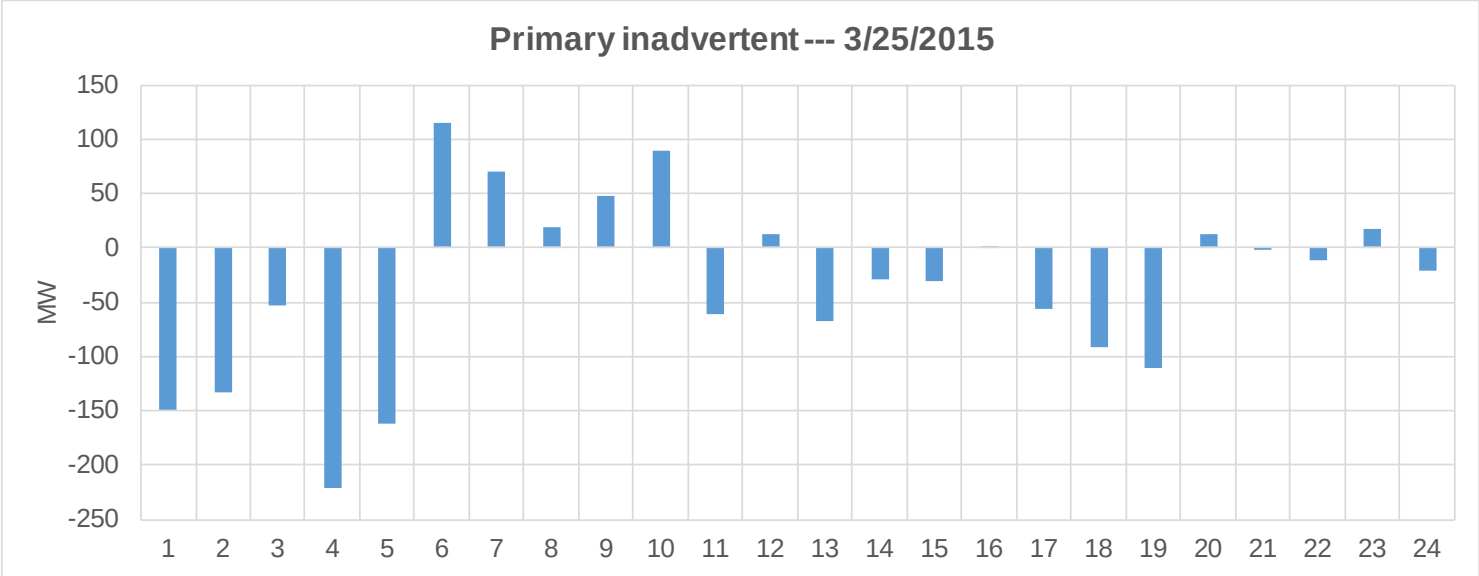


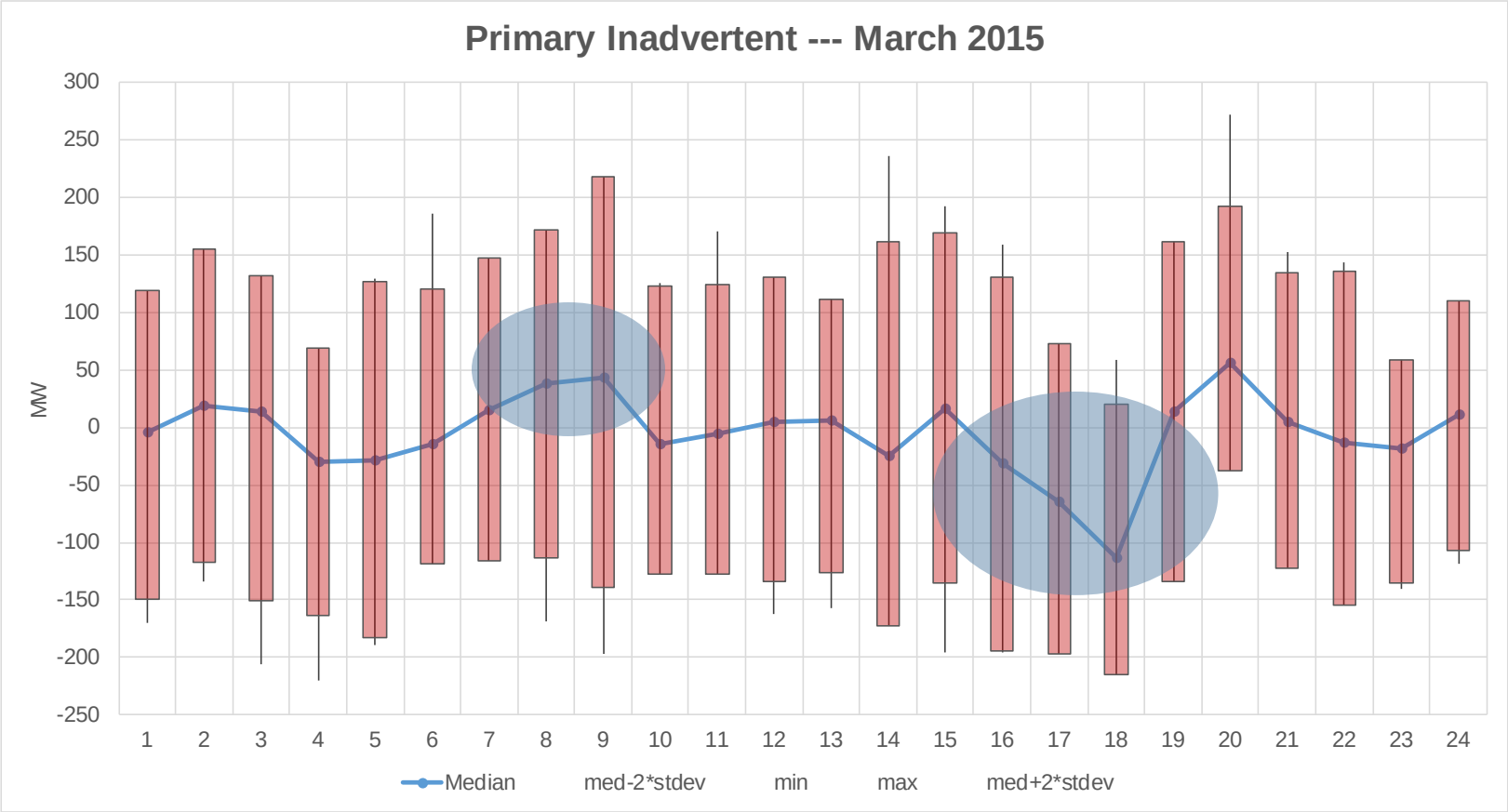


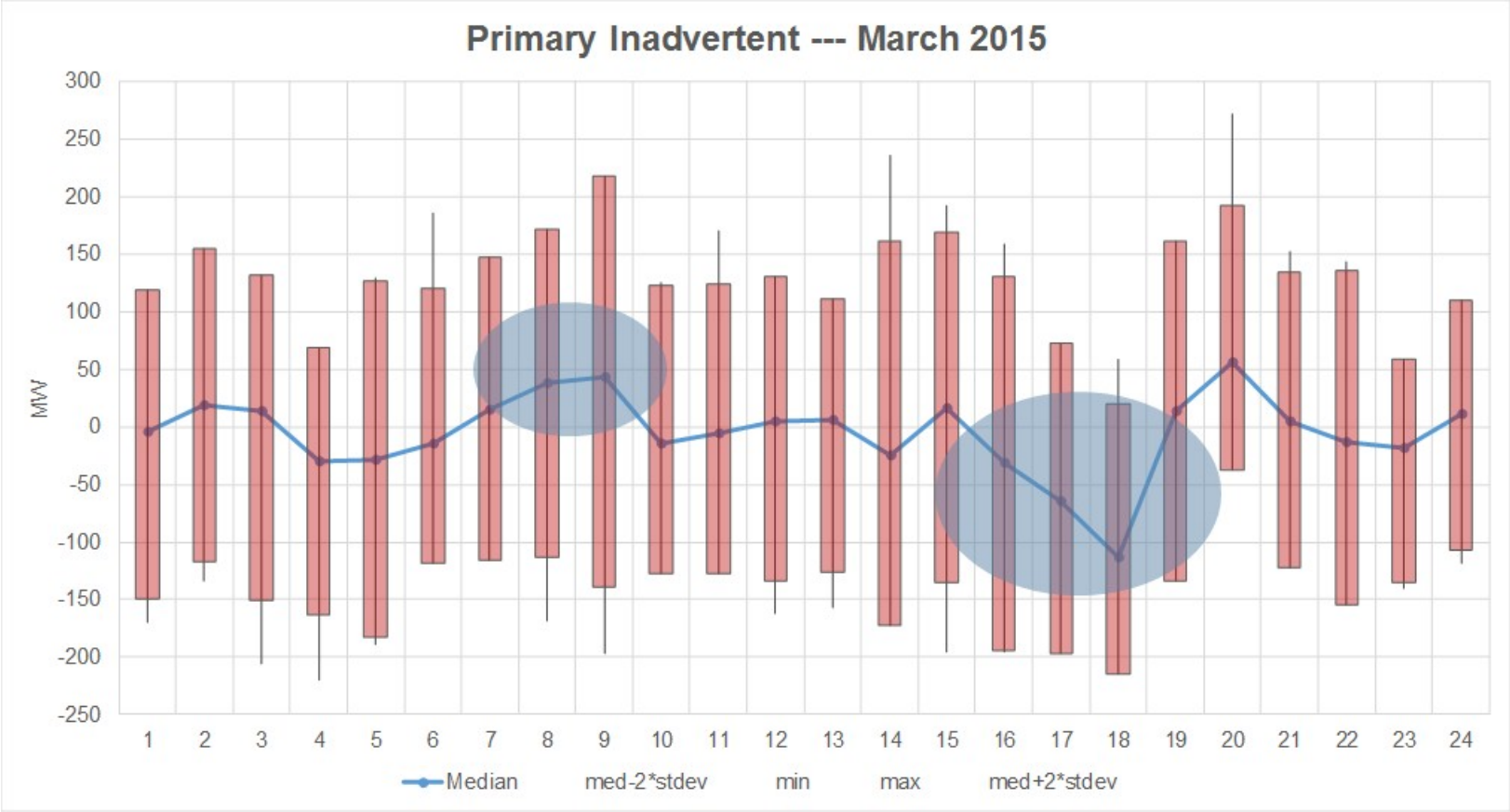
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Low	0	0	0	0	0	0	0	0	2	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0
High	0	0	0	1	13	0	1	9	4	0	0	0	0	0	0	0	0	9	2	6	7	0	0	0

Wind / Solar ramps vs. Primary Inadvertent

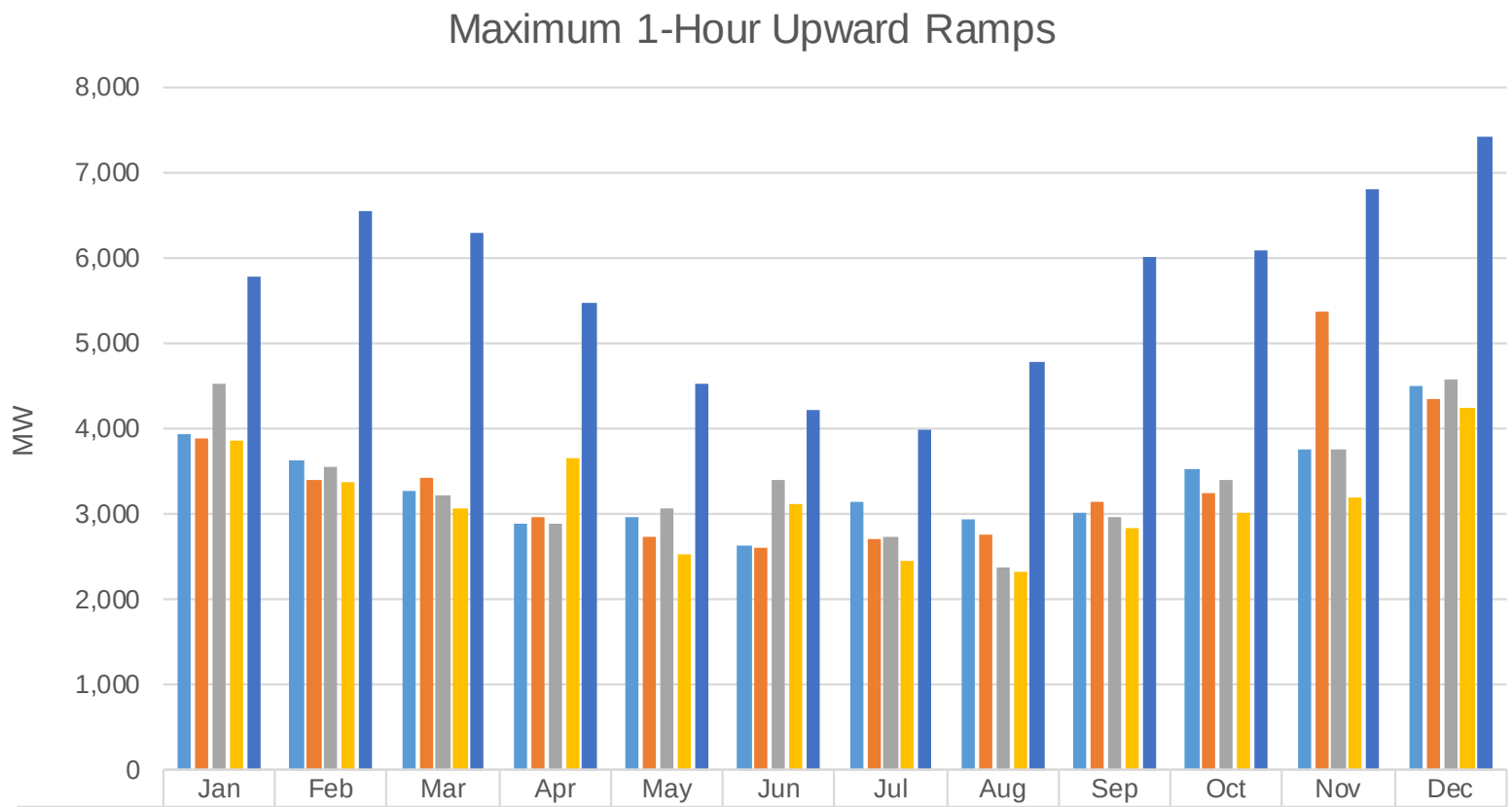





Primary Inadvertent --- March 2015
MW
300
250
200
150
100
50
0
-50
-100
-150
-200
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Median
med-2*stdev
min
max
med+2*stdev

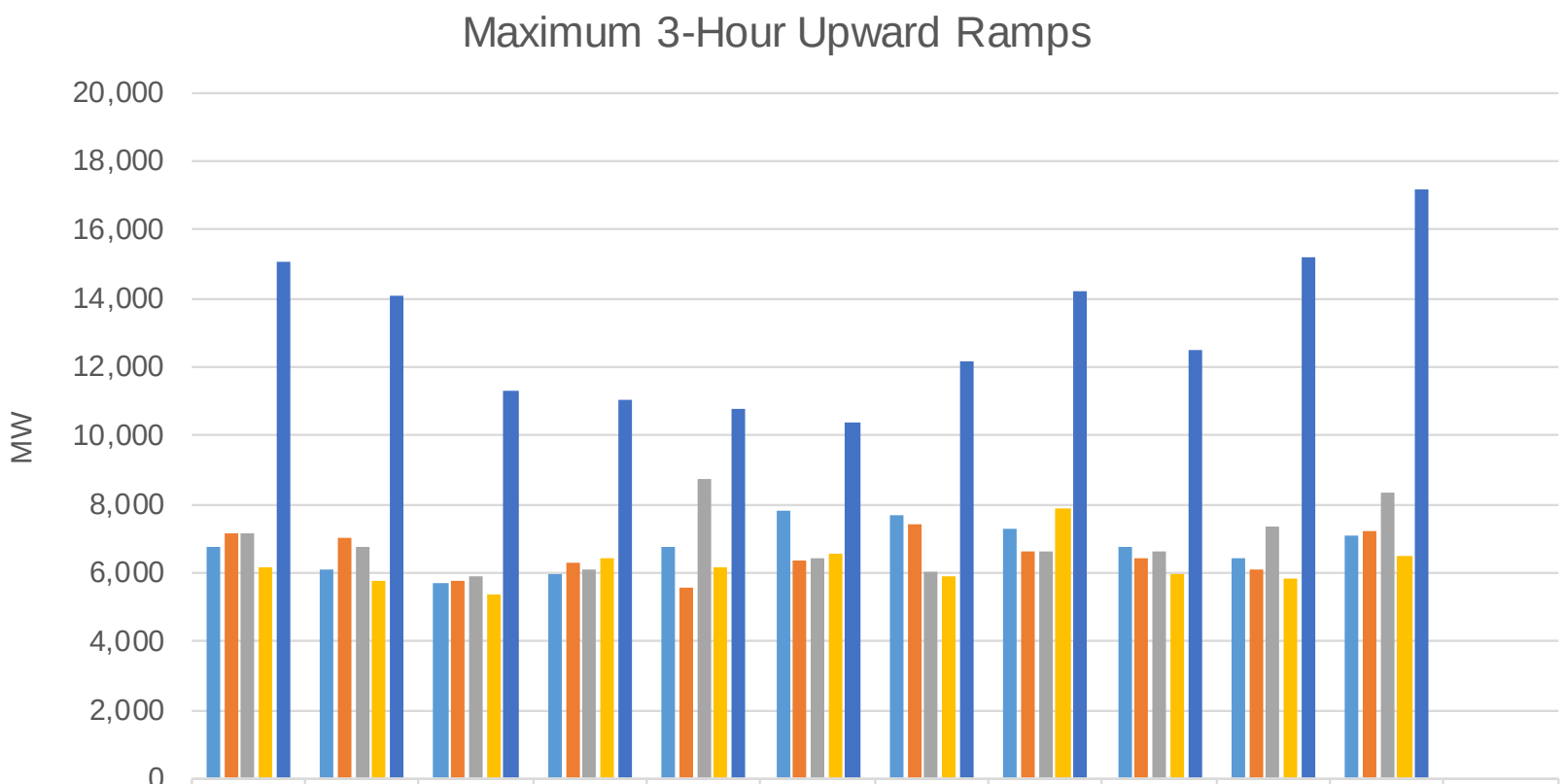

Primary Inadvertent --- March 2015
MW
300
250
200
150
100
50
0
-50
-100
-150
-200
-250
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Median
med-2*stdev
min
max
med+2*stdev

CAISO: 1-Hour Upward Ramping Needs



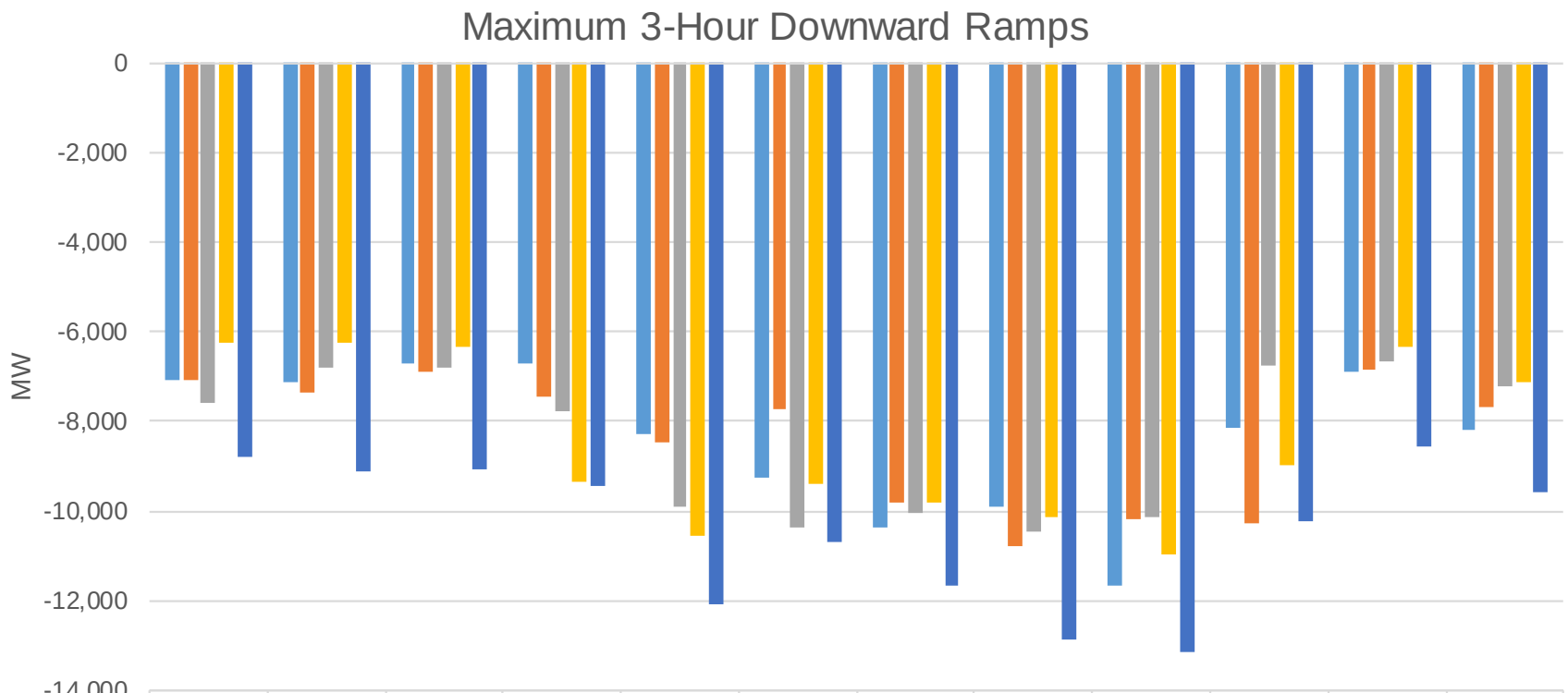
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011_1h	3,935	3,630	3,271	2,897	2,951	2,637	3,137	2,933	3,004	3,514	3,746	4,506
2012_1hr	3,875	3,394	3,428	2,959	2,736	2,606	2,695	2,766	3,143	3,240	5,358	4,352
2013_1hr	4,524	3,557	3,224	2,893	3,072	3,401	2,723	2,380	2,964	3,406	3,759	4,567
2014_1hr	3,862	3,374	3,064	3,653	2,527	3,128	2,446	2,320	2,848	3,012	3,192	4,235
2018_1hr	5,790	6,545	6,298	5,459	4,515	4,220	3,976	4,774	5,999	6,084	6,794	7,420

CAISO: 3-Hour Upward Ramping Needs



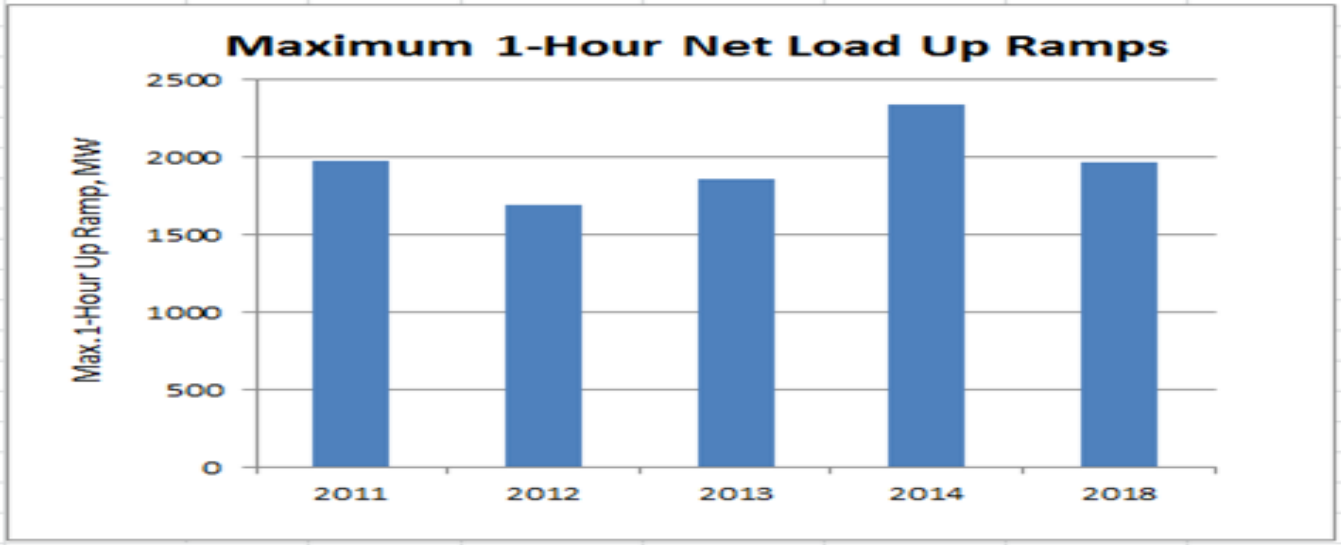
	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011_3hr	6,766	6,067	5,688	5,942	6,732	7,822	7,702	7,251	6,767	6,433	7,098
2012_3hr	7,173	7,028	5,774	6,278	5,543	6,367	7,410	6,591	6,422	6,062	7,211
2013_3hr	7,171	6,736	5,881	6,096	8,745	6,426	6,024	6,591	6,609	7,355	8,343
2014_3hr	6,170	5,755	5,363	6,394	6,177	6,559	5,879	7,862	5,952	5,844	6,494
2018_3hr	15,048	14,100	11,332	11,022	10,769	10,390	12,143	14,174	12,509	15,190	17,179

CAISO: 3-Hour Downward Ramping Needs

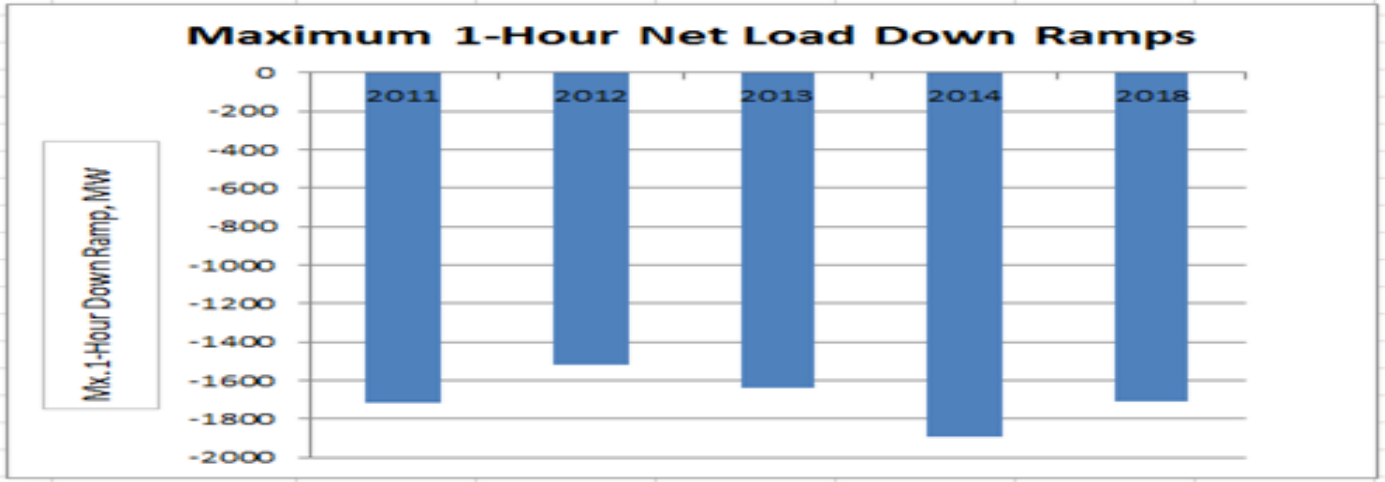


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011_3hr	-7,091	-7,118	-6,711	-6,690	-8,276	-9,248	-10,362	-9,919	-11,684	-8,162	-6,900	-8,202
2012_3hr	-7,083	-7,363	-6,900	-7,472	-8,472	-7,734	-9,804	-10,775	-10,195	-10,256	-6,865	-7,680
2013_3hr	-7,600	-6,794	-6,806	-7,769	-9,908	-10,357	-10,023	-10,438	-10,136	-6,765	-6,643	-7,227
2014_3hr	-6,258	-6,263	-6,350	-9,330	-10,538	-9,395	-9,813	-10,128	-10,981	-8,996	-6,346	-7,113
2018_3hr	-8,815	-9,106	-9,086	-9,418	-12,068	-10,684	-11,676	-12,871	-13,143	-10,223	-8,541	-9,572

BC Hydro 1-Hour Ramps

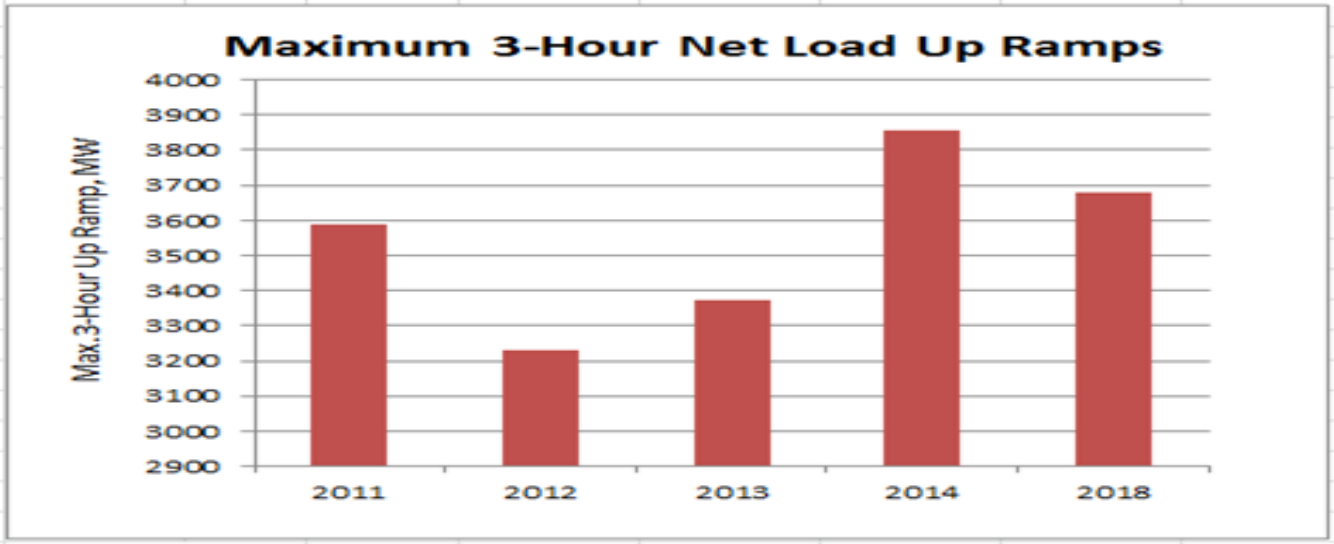


Max 1_Hr_Up	1981	1697	1862	2344	1966

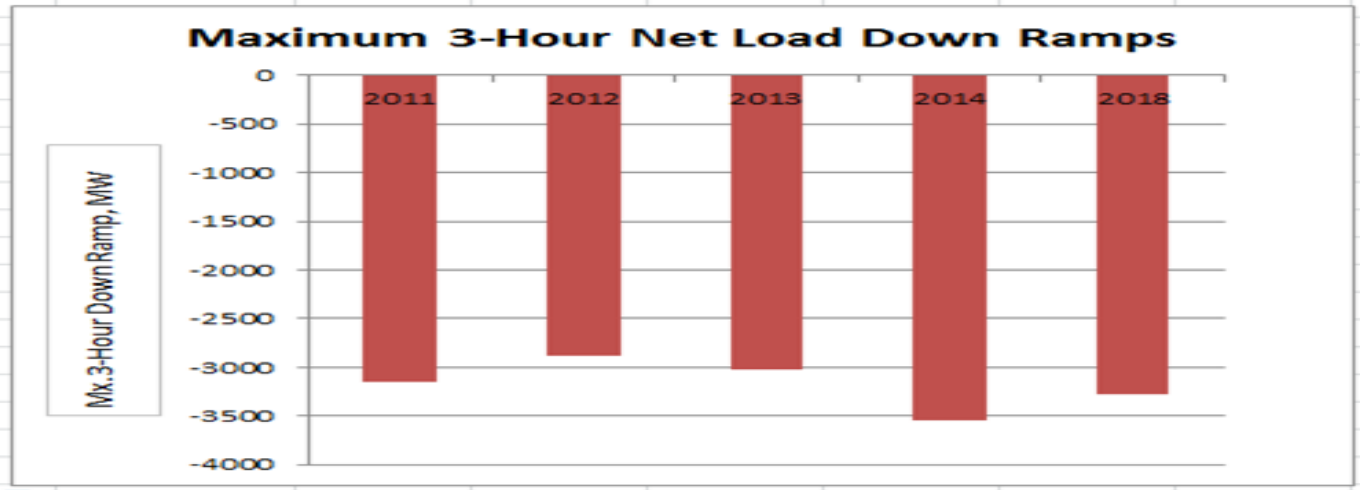


Max 1_Hr_Dn	-1719	-1520	-1638	-1894	-1711

BC Hydro 3-Hour Ramps

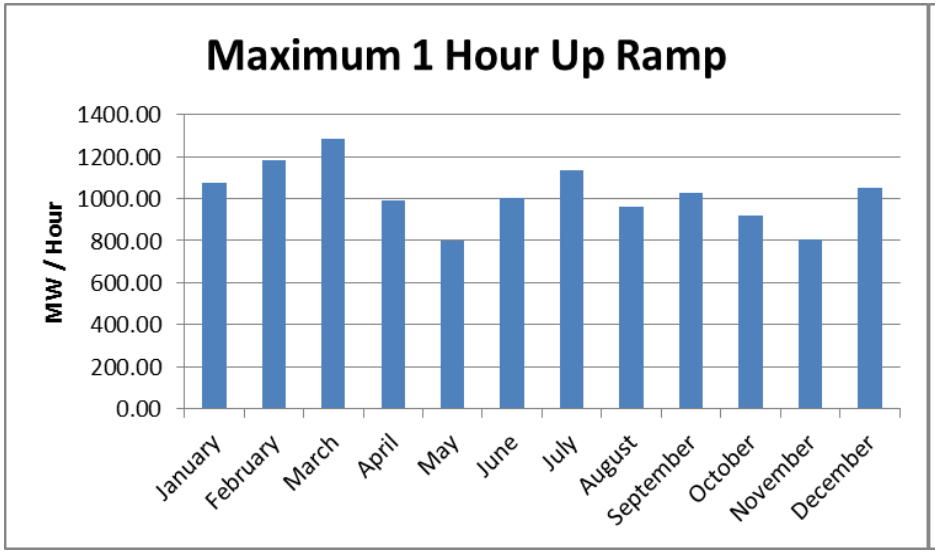


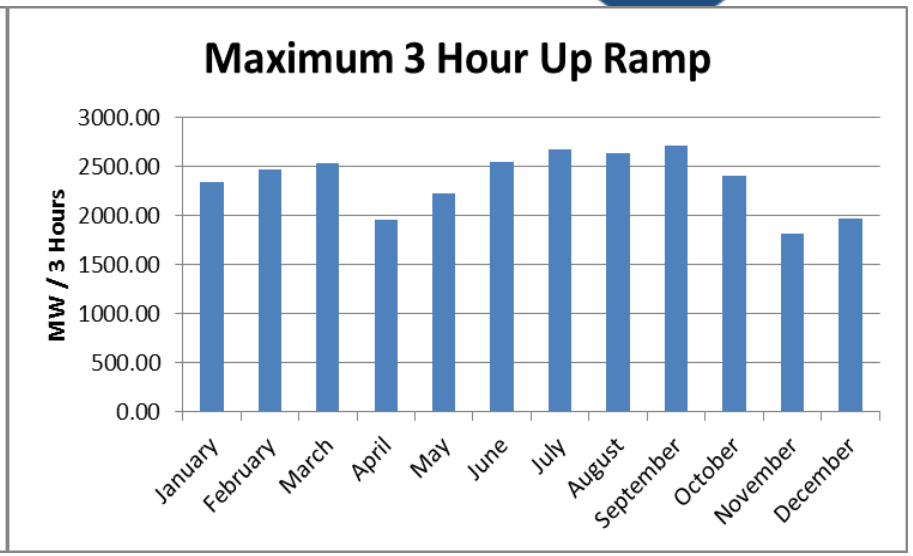
Max 3_Hr_Up	3589	3230	3372	3856	3680

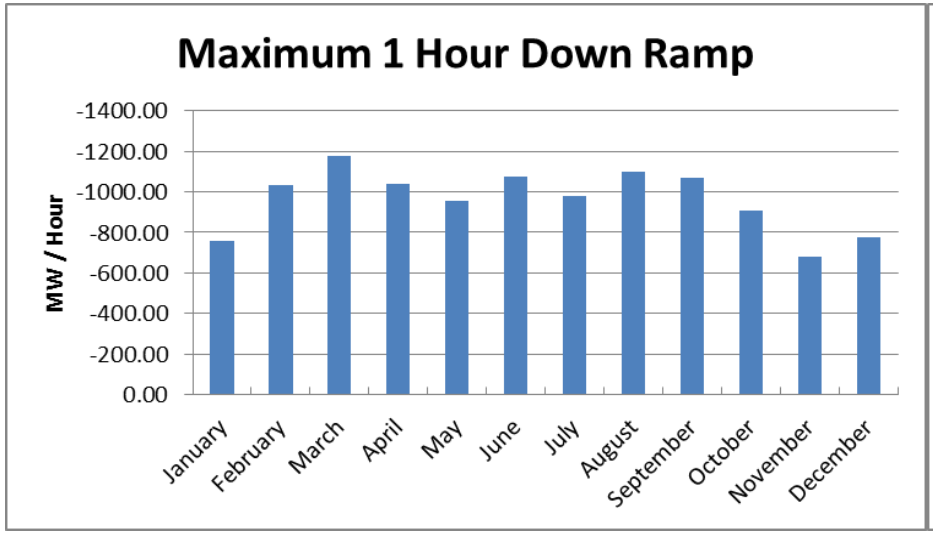


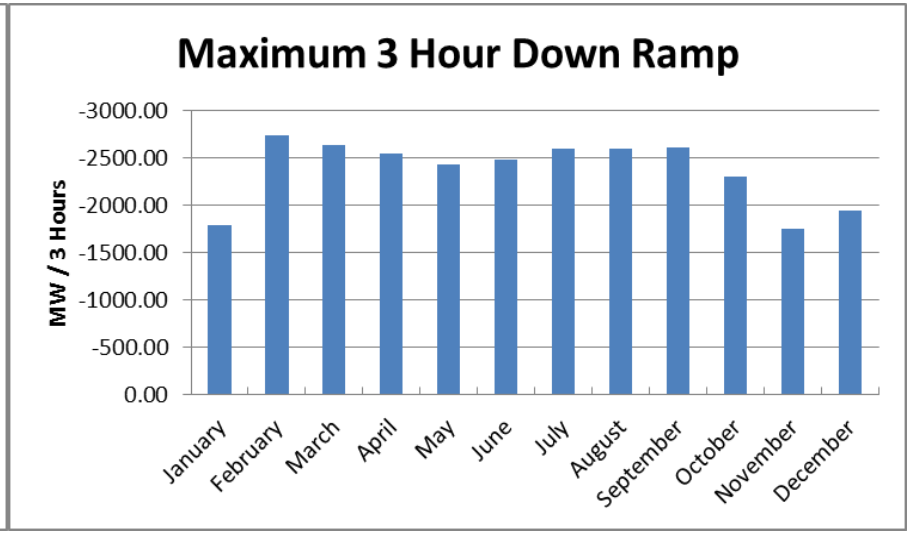
Max 3_Hr_Dn	-3152	-2885	-3025	-3547	-3282

Duke Energy Florida (DEF)

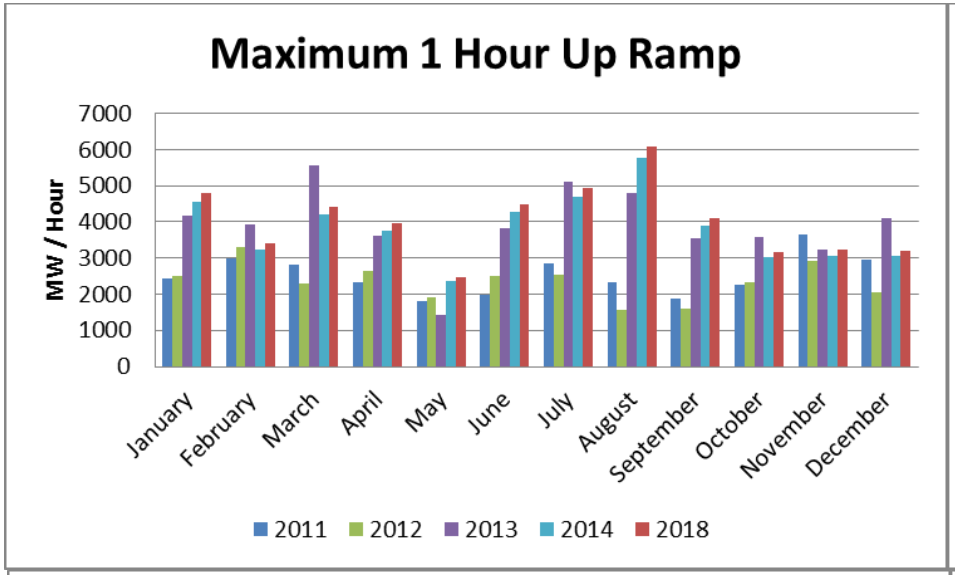


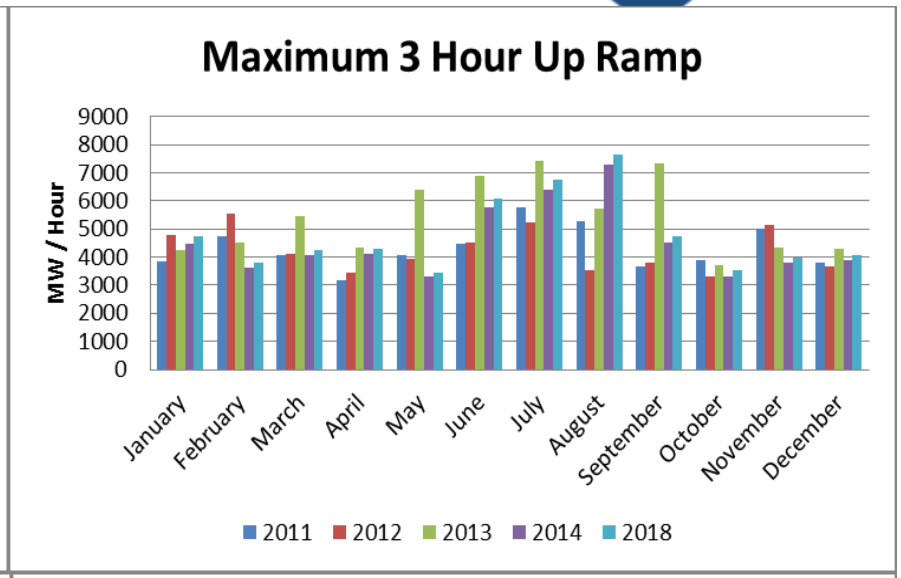


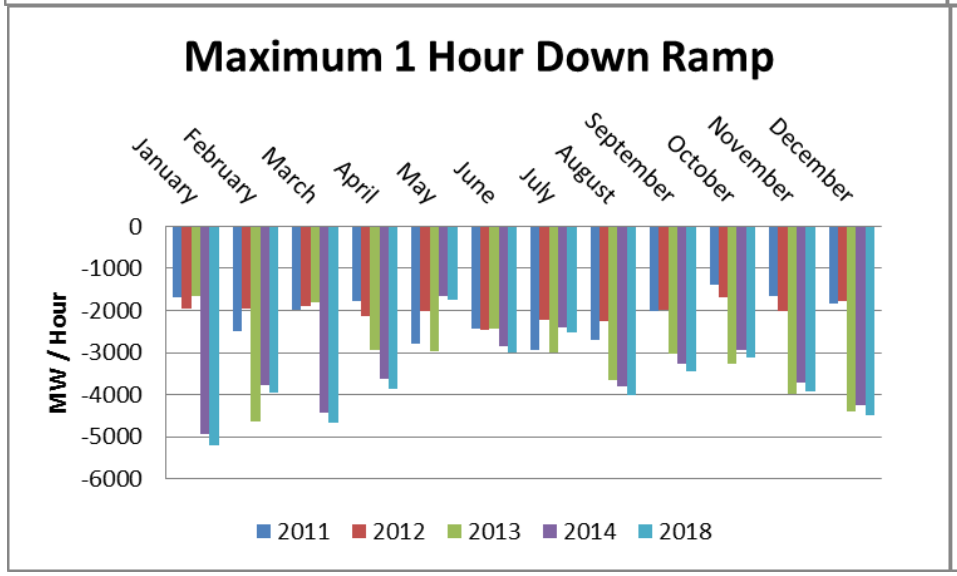


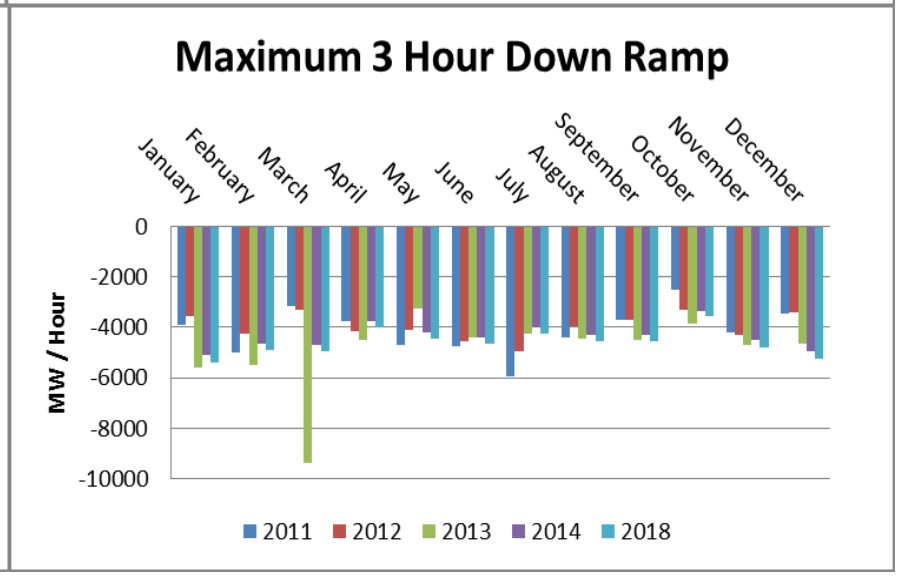


Duke Energy Carolinas (DEC)

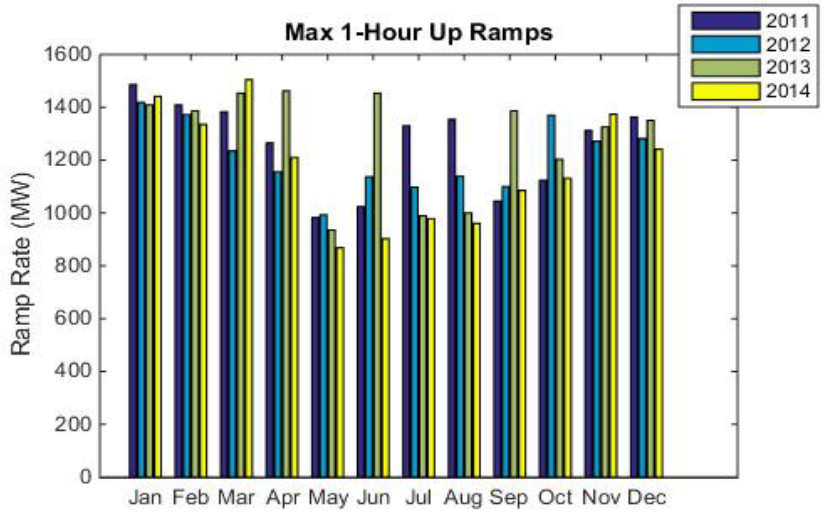


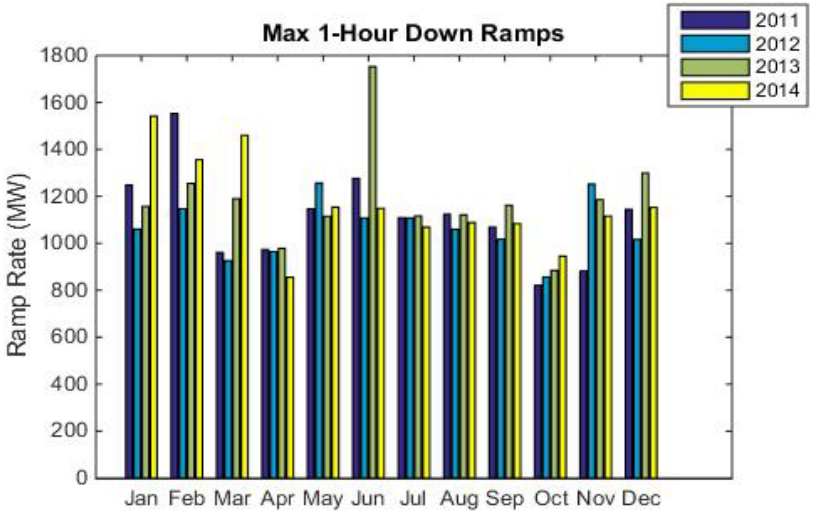


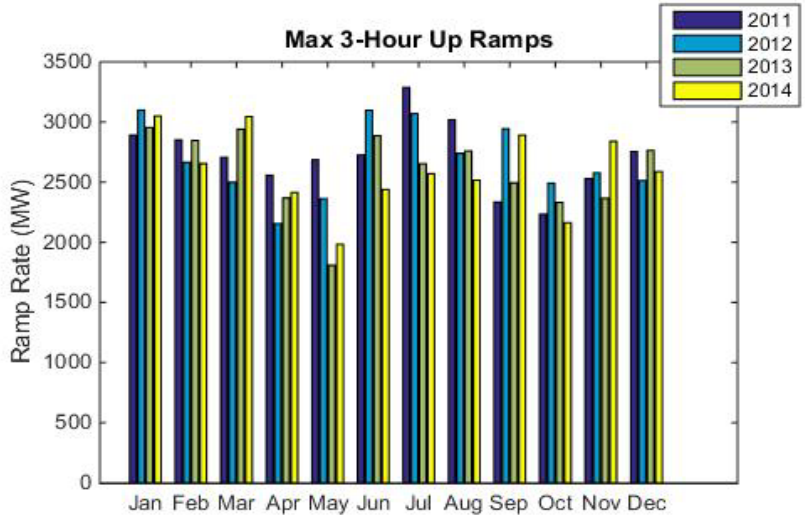


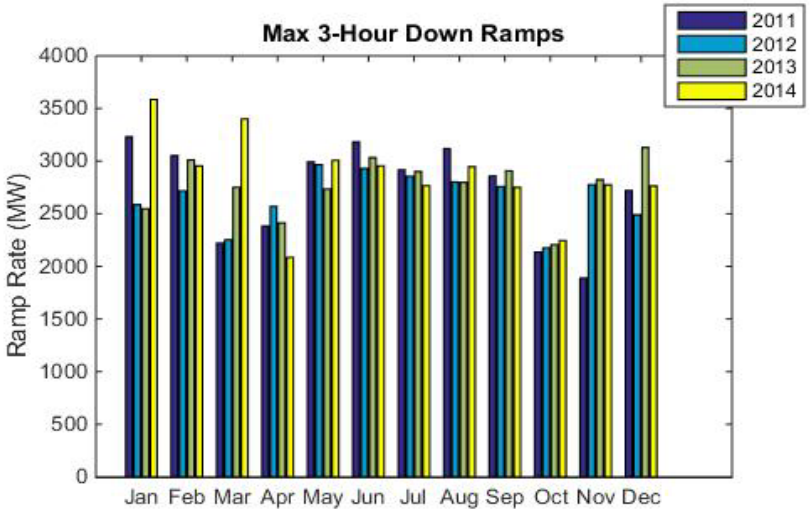


Duke Energy Progress (DEP)









Southern Company

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	6166	-6325	11714	-10096
2012	5560	-4376	10385	-9614
2013	4192	-4521	9034	-9072
2014	4423	-3868	9911	-9236
2015	4423	-3868	9911	-9236
2016	4423	-3868	9911	-9236
2017	4423	-3868	9911	-9236

Year	Wind Capacity, MW	PV, MW
2011	0	0
2012	0	0
2013	202	46
2014	404	50
2015	404	1182
2016	654	1182
2017	654	1670

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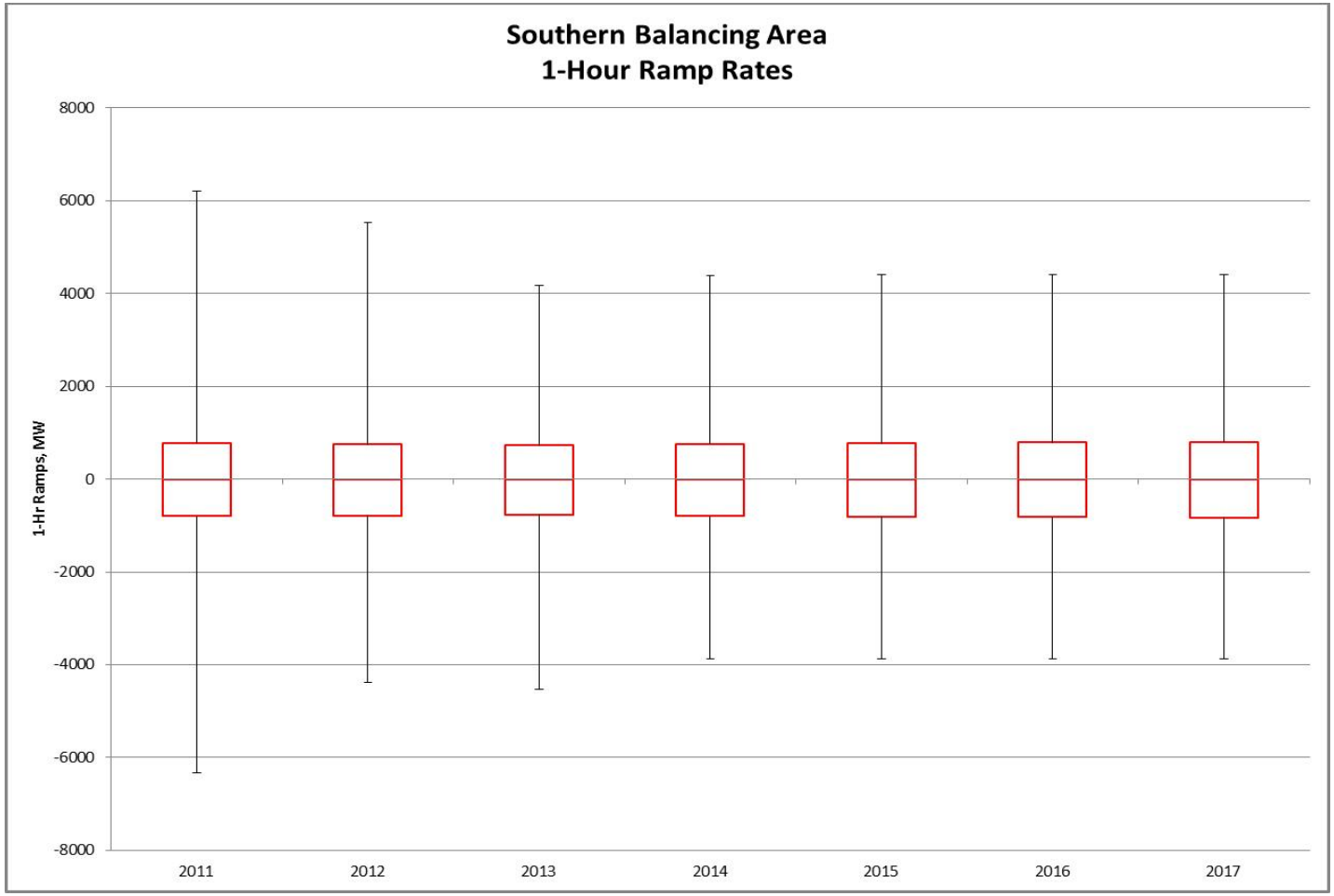

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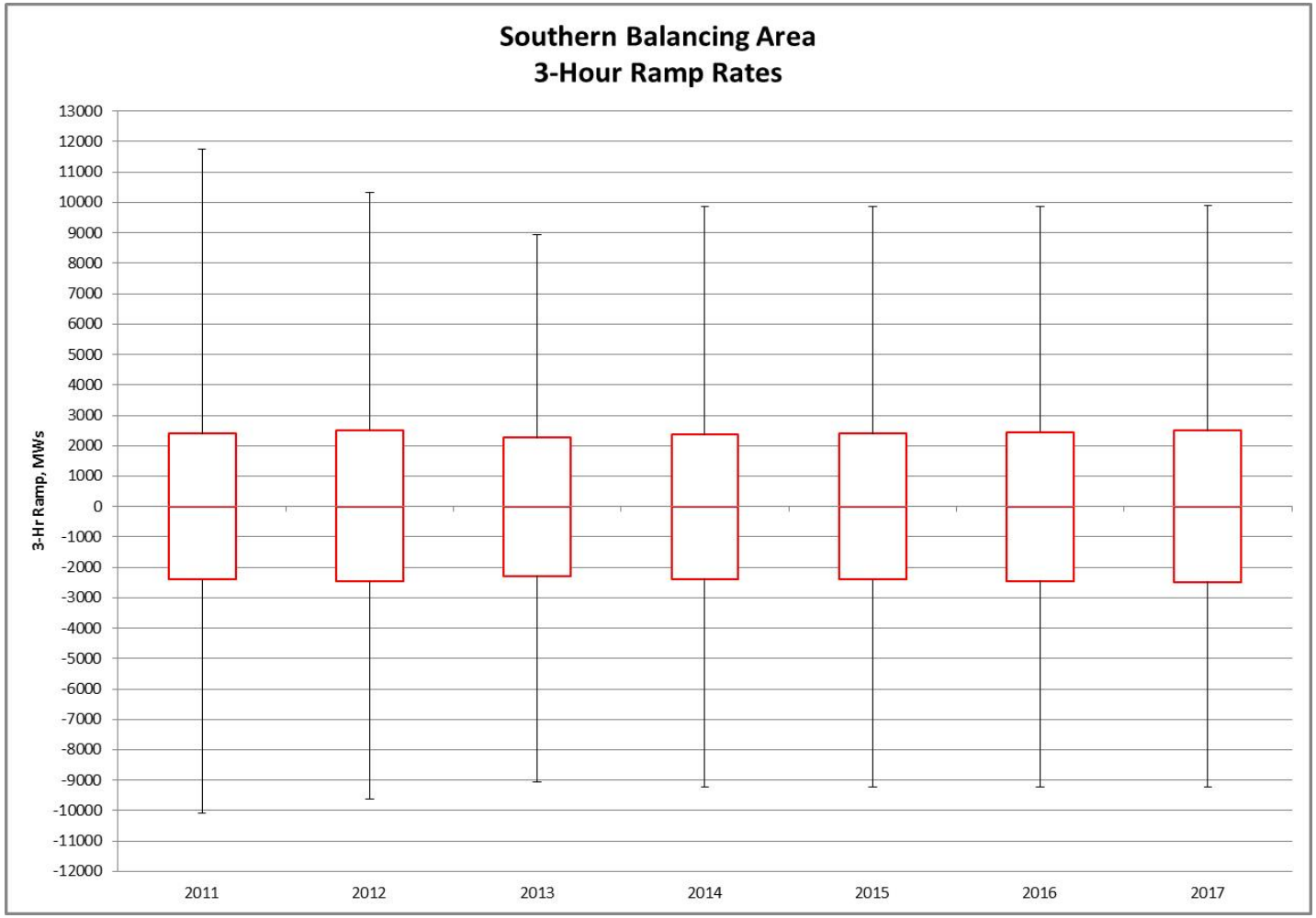
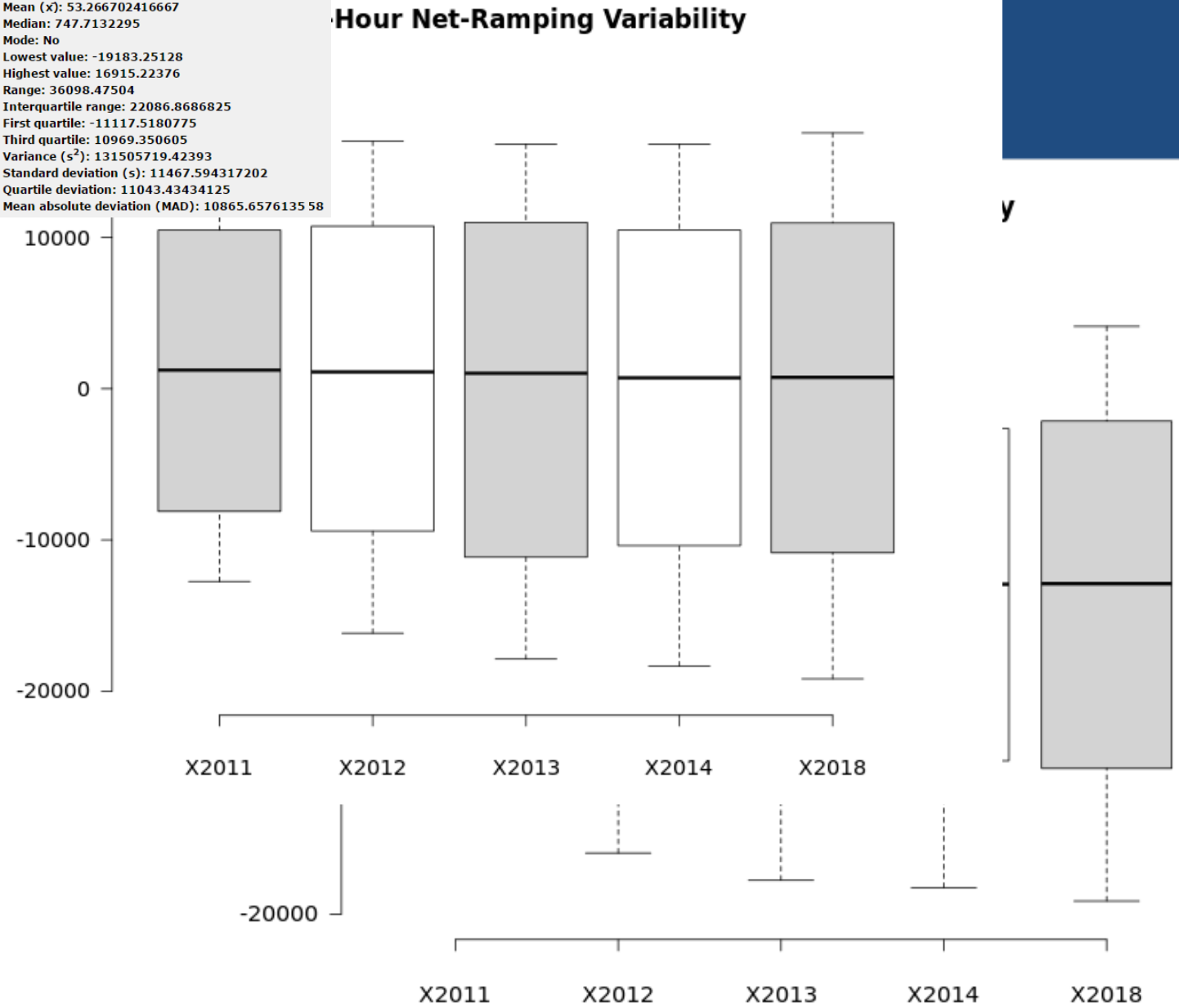
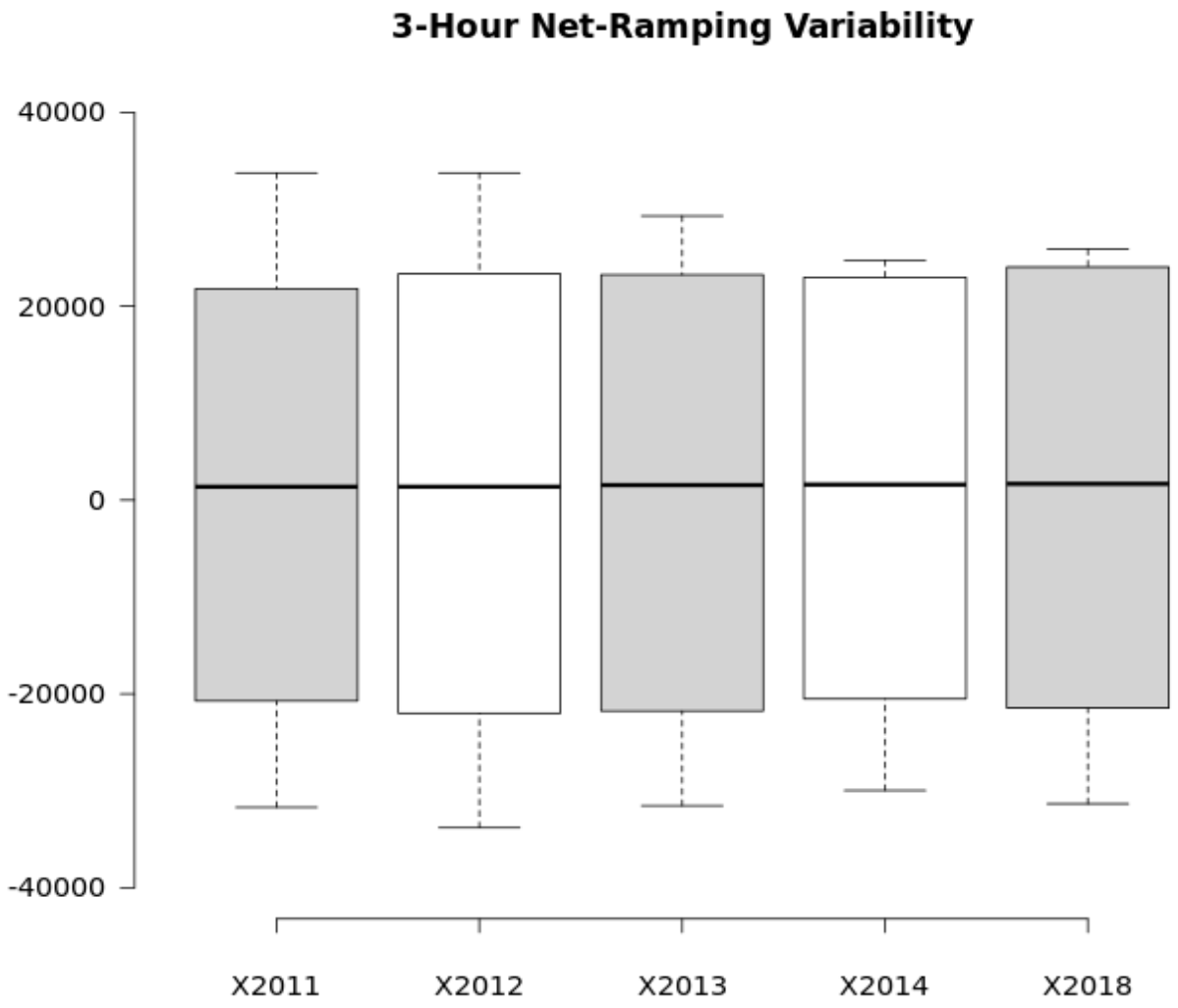


Todd Lucas

Mean (x): 53.266702416667
Median: 747.7132295
Mode: No
Lowest value: -19183.25128
Highest value: 16915.22376
Range: 36098.47504
Interquartile range: 22086.8686825
First quartile: -11117.5180775
Third quartile: 10969.350605
Variance (s^2): 131505719.42393
Standard deviation (s): 11467.594317202
Quartile deviation: 11043.43434125
Mean absolute deviation (MAD): 10865.6576135 58



PJM



Ken Schuyler

Questions and Answers

Reactive Power and Voltage Control Recommendation - NERC should consider revisions to FAC-001 expanding R.2.1.3 or as an Appendix, stating that interconnection standards for reactive power must cover specifications for **minimum static and dynamic reactive power requirements** at full power and at partial power, and how terminal voltage should affect the power factor or reactive range requirement.Recommendation: NERC should promote greater uniformity and clarity of reactive power requirements contained in connection standards that Transmission Operators have issued pursuant to FAC-001. NERC, FERC and other applicable regional standards should be reconciled	**ERSTF**	FAC-001-1--Guidelines and Technical Basis section: While the SDT has made the standard less prescriptive, the Guidelines and Technical Basis suggests that TOs consider including "data required to properly study the interconnection" in their Facility interconnection requirements, which should capture any specific requirements for data from variable generation plants. Providing reactive power is an essential reliability service. Conventional generation provides a dynamic source of reactive power. The NERC ERSTF should explore the minimum levels of dynamic and static reactive power requirements for new forms of variable generation.	Does ERSTF agree? - No. The ERSTF does not agree. We have a couple measures that could support the proposed recommendation, however does not propose changing the FAC standards.
Reactive Power and Voltage Control Recommendation: NERC should consider revisions to **VAR-001** standards to include the term "plant-level volt/var controller" (in addition to "AVR"), which is more appropriate for variable generation	**Standards Review and/or Standards Authorization Request**	VAR-001-4 R4 and R5 specifically call out "AVR" in the language. "AVR" is a term specific to conventional generation technology using synchronous machines with closed-loop voltage control executed by an exciter at each generator. "AVR" does not refer to the plant-level closed-loop voltage control provided by wind and solar plants. Wind and solar plants have the capability to regulate voltage and follow voltage schedules per the VAR-001 standards using a "plant-level volt/var controller". If "AVR" alone is used in the	OK
Reactive Power and Voltage Control Recommendation: NERC should consider initiating a Standards Authorization Request (SAR) to establish minimum reactive power capability standards for interconnection of all generators, and provide clear definitions of acceptable control performance. ERC should consider initiating a Standards Authorization Request (SAR) to establish	**Standard Authorization Request**	NERC may initiate a SAR in order to determine industry need.	Tend to disagree, one size doesn't fit all at a NERC level. Also shouldn't it be a GO requirment

Reactive Power and Voltage Control Recommendation: Applicability: Generator interconnection requirement for reactive power should be clearly established for all generator technologies. NERC should consider giving transmission planners some discretion to establish variance based on the characteristics of their transmission system and the size of the generator.	**ERSTF?**	The majority of recommendations fall into the category "Planning Approaches – Technical Guidelines". The IVGTF T1.3 to review the above list to determine which recommendation warrants a Standard Review/SAR. Will NERC commission a separate TF to develop a technical guidance document or will this be given to the ERSTF?	ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee
Reactive Power and Voltage Control:Specification of Reactive Range: The reactive range requirement should be defined over the full output range, and it should be applicable at the point of connection	**ERSTF?**		ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee
Reactive Power and Voltage: Impact of System Voltage on Reactive Power Capability: It should be recognized that system voltage level affects a generating plant's ability to deliver reactive power to the grid and the power system's requirement for reactive support.	**ERSTF?**		ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee
Reactive Power and Voltage Control: Specification of Dynamic Reactive Capability: The standard should clearly define what is meant by "Dynamic" Reactive Capability by specifying the portion of the reactive power capability that is expected to be dynamic. A prospective standard should specify the minimum performance characteristic of the response in terms of response time, granularity (maximum step size), and repeatability (close-open-close cycling capability).	**ERSTF?**		ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee
Recommendation: Definition of Control Performance –Expected volt/var control performance should be specified, including minimum control response time for voltage control, power factor control and reactive power control. An interim period for the application of precisely defined control capabilities should be considered.	**ERSTF?**		ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee
Reactive Power and Voltage Control: Effect of Generator Synchronization on System Voltage: Synchronization of generators to the grid should not cause excessive dynamic or steady-state voltage change at the point of connection. A 2 percent limit may be considered as a baseline.	**ERSTF?**		ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee
Reactive Power and Voltage Control: Special Considerations: NERC should investigate whether transmission operators can, under some conditions, allow variable generating plants to operate normally or temporarily at an active power level where dynamic reactive capability is limited or zero.	**ERSTF?**		ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee

Reactive Power and Voltage Control: Technical Alternatives for Meeting Reactive Power Capability -The reactive power requirements should be applicable at the point of interconnection.	**ERSTF?**		ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee
Reactive Power and Voltage Control: Commissioning Tests – Commissioning tests, which are part of the interconnection process, often include a test to demonstrate plant compliance with reactive power capability requirements.	**ERSTF?**		ERSTF will end up getting this, do they agree? No - The ERSTF recommends that this go back to Standards Committee
Performance During and After Disturbances Recommendations: 1. The scope of PRC-024-1 should be broadened to cover smaller plant sizes. The current proposal of 75 MVA will miss many variable generator facilities that could impact the Bulk Electric System. It is suggested that the scope be broadened to cover all projects under a Large Generator Interconnection Agreement. 2. Or extend the scope to any project greater than 10 MW in order to provide coverage for plants not included under IEEE 1547 Recommended that industry decide the appropriate threshold (10 vs. 20 MW or MVA) as Regional differences may be justified. Applicability should depend on total plant rating and should not be based on individual unit size. Bulk Electric System (BES) definition describes facilities that are included in, and excluded from, the BES. If it is determined that a facility (or aggregation of units) impacts BES reliability, that facility will be accounted for through the BES inclusion process. Response: As of July 1, 2014, the effective Bulk Electric System definition includes the following "Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.	**Definition – Revisions or Addition by NERC or ERSTF**	**Response 1**: The modified BES definition does not address the substantial reliability risk posed to the BES by growing penetrations of wind and particularly solar facilities connected at voltages below 100kV. The performance of these facilities during and after disturbances are relevant now in some systems or will become relevant once a significant penetration point is reached in other systems to bulk system dynamic performance and fault recovery. The T1-3 team believes "No Action" should be modified to "Definition – Revisions or Addition by NERC" or "ERSTF" **Response 2**: I would recommend that the ERSTF track the growth of variable generation that fall outside the NERC BES definition.	Who determines reid through spec, NERC, IEEE, ect? Can you develop a one size fits all? Will ERSTF do this? No. The ERSTF does not agree. We have language in the report that could support the proposed recommendation, however does not address the needs for standards revisions

Disturbance Ride Through Recommendations PRC-024 Recommendations: PRC-024 should clearly define performance requirements for unbalanced and balanced faults. The specification of voltage magnitude should define what voltage metric is applicable.	**ERSTF**	**Response 1:** The T1-5 team agrees this recommendation has been addressed in the existing version of PRC-024-1 (subject to full enforcement). REIGH/Everyone, do you agree? "No Action" transition category is appropriate. **Response 2:** The purpose of PRC-024-1 or PRC-024-2 is to define under what voltage and frequency conditions the generator remains connected. The standard provides zones of voltage and frequency that define no trip and trip areas. The standard says nothing on how the generator should be behaving or performing in the no trip zone. For example,	Will ERSTF do this? No. The ERSTF does not agree. We have language in the report that could support the proposed recommendation, however does not address the needs for standards revisions
Recommendation: Voltage disturbance performance requirements, particularly high-voltage ride-through, should use the severity-cumulative duration form of specification to avoid unnecessary	**Standards Review**	The response is not clear which recommendations they are referring to. The first recommendation is pointed toward PRC-024 and recommends a different type of high voltage ride curve. Therefore, PRC-024 needs a Standards Review. The other two	tend to agree but can you have a one size fits all standard?
Recommendation: Suggested that ride-through plots be provided that specify both high- and low-voltage ride-through requirements. It is recommended that the zero voltage ride-through should be equal to the three-phase fault clearing time on the network. The zero voltage ride-through is up to 9 cycles but may be less depending on the clearing time. This should be made explicit in any	**Planning Approaches and Technical**		
Disturbance Ride Through Recommendation: It is not suggested that a NERC-wide requirement be mandated for riding through a rate of frequency change. If a standard is desired by individual operators, a rate-of-change ride-through requirement of 2.5 Hz/s appears adequate. (This rate of frequency change is stipulated in the current draft of PRC-024). There may be some Regional differences where at least 4.0 Hz/s is required.	**Planning Approaches and Technical Guidelines**	The above response is not appropriate. The rate of change of frequency should be discussed in a technical guidance document.	Not sure if all planners are on board, good consideration but that's about it.

PRC-024, should indicate the maximum level of transmission contingency (e.g., N-1-1) for which a plant should be required to ride through. Response: It appears this recommendation is already addressed by PRC-024-1 (subject to future enforcement), which includes requirement R.2. which states: "Each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the Generator Owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study." PRC-024-1 Attachment 2 states: "Voltage Ride-Through Curve Clarifications, Curve Details: 1. The per unit voltage base for these curves is the	**No Action**	The T1-3 team agrees this recommendation has been addressed in the existing version of PRC-024-1 (subject to full enforcement). The scope of PRC-024 has been modified from a generator performance requirement (which was the case when this IVGTF recommendation was written) to a protective relaying requirement. "No Action" transition category is appropriate. I agree – ride through is specified based on voltage and frequency in PRC-024. The TPL-001-4 standard covers contingency levels for BES generation.	ok
Disturbance Ride Through Recommendation: Disturbance performance requirements, such as PRC-024, should clearly define any requirement for repeated disturbances.	**Standard Review**	Response 1: Repeat disturbances reoccurring within a short time (such as reclosings, non-bolted or arcing faults) are not covered in the existing version of PRC-024. The ambiguity in the standard causes confusion as to how multiple successive disturbances are treated (either as a single event or as multiple separate events). This confusion and/or a poor interpretation may result in non-compliance of the regulation while that result was not intended by the SDT. REIGH/Everyone, do you agree?	ok

Disturbance Ride Through Recommendation: PRC-024 should define the performance required during and after disturbances and should make clear and unambiguous statements as to what remaining "connected" entails. It is not recommended that active power be required during a voltage disturbance unless there is a reliability concern. The sourcing of reactive power during a severe fault should instead be given priority over real power delivery, and the magnitude of reactive power should be consistent with pre-fault reactive power capability. The capability to supply reactive current during a fault varies with technology and product offerings, and so a market to incentivize, but not require, the increased sourcing of reactive current during a voltage dip is recommended.	**ERSTF**	**Response 1:** The modification of the scope of PRC-024 from a performance to a relaying standard after this recommendation was given has caused the language to be clarified regarding what it means to remain "connected". This was accomplished by the statement "Each Generator Owner that has generator voltage protective relaying activated to trip its applicable generating unit(s) shall set its protective relaying such that the generator voltage protective relaying does not trip the applicable generating unit(s) ..." The T1-3	Does ERSTF want to do this? No. The ERSTF does not agree. We have language in the report that could support the proposed recommendation, however does not address the needs for standards revisions
Power Recovery after Blackout Recommendation: Recovery after Blackout: It is reasonable to clarify the restart expectations of a generator facility following a disturbance. In some cases, the Transmission Operator provides a signal to the facility that prohibits automatic restarting after a severe grid event. FAC-001 could be modified to include a facility connection requirement to	**Planning Approaches and Technical**	Recommend to provide some technical guidance for industry – agree that additional standards are not required.	ok
Recommendation to Require Capability to Limit Rate of Increase of Power Output: Variable generation plants should be required to have the capability to limit the rate of power increase. This type of up ramp rate control capability has been required in some other systems. This function should include the ability to be enabled and disabled by instruction from Transmission Operator, Balancing Authority, or Reliability Coordinator Recommendation: Plants must be able to accept commands to enable pre-selected ramp rate limits. Plants should be designed with recognition that ramp rate limits should not be required under all operating conditions. It should not be required that variable generation plants limit power decreases due to declines in wind speed or solar irradiation (i.e., down ramp rate limits). However, limits on decrease in power output due to other reasons, including curtailment commands, shut-down sequences, and responses to market conditions can be reasonably required.	**ERSTF**	Ok – Should say something like ERSTF will determine minimum ramp rates required for essential reliability.	ERSTF will end up getting this, do they agree? No. Consider this item for SAMS group.

Recommendation on Encourage or Mandate Reduction of Active Power in Response to High Frequencies: Variable generation plants should be encouraged to provide over-frequency droop response of similar character to that of other synchronous machine governors.	**ERSTF**	Should say something like ERSTF will determine recommended over-frequency control required for essential reliability.	ERSTF will end up getting this, do they agree? No - No action needed from ERSTF. 2012 Frequency Response initiative called for Freqeuncy Response Guideline and will be written by RISA (RAPA)
Consider Requiring the Capability to Provide Increase of active Power for Low Frequencies: Variable generation plants should not be required to provide governor-like frequency response for low frequency under normal operating conditions. This is consistent with any conventional power plant operating at full throttle output (i.e., valves wide open). However, encouraging VGs to have the capability to provide this response, and then establish rules and possibly compensation for when such controls would be enabled, could be considered. This presumably would be a rare occurrence, as the economic penalty associated with enabling these controls is high.	**ERSTF**	Should say something like ERSTF will determine recommended under-frequency control required for essential reliability.	ERSTF will end up getting this, do they agree? No - No action needed from ERSTF. 2012 Frequency Response initiative called for Freqeuncy Response Guideline and will be written by RISA (RAPA)
Recommendation on Consider Requiring Inertial Response in Near Future: With the exception of Hydro-Québec, inertia response characteristics have not been specified in grid codes or interconnection requirements for wind plants. Furthermore, language describing this functionality in technology-neutral terms and subject to the physical reality of variable generation facilities is not presently available. Requiring this function in the future as the technology matures and as grid operators and reliability organizations learn more about the need for inertial response characteristics from wind plants should be evaluated further. However, incremental costs should be carefully weighed against alternatives on both the supply and demand side for providing this important reliability service.	**ERSTF**	Should say something like ERSTF will determine recommended inertial response required for essential reliability.	ERSTF will end up getting this, do they agree? Measure 4 of the ERSTF report will address some of these concerns.
Recommendation on Harmonics and Subsynchronous Interaction: There is no need for NERC to develop interconnection criteria related to SSR/SSI or harmonics at this time. However, it would be prudent for transmission owners and grid operators to: 1) Consider design study reports that assess the harmonic performance of all wind and solar plants, and 2) Until better	**Planning Approaches and Technical**	No Updated Response	OK

Standards for Manufactured Equipment Recommendation: Current solar PV inverters designed to comply with IEEE 1547 are required to provide anti-islanding capability and disconnection requirements that are not compatible with the fault ride through requirements recommended here. Although individual inverters may have capacities on the order of 500kW, utility scale PV plants may have hundreds of these units and hence have a plant capacity of upwards of 100 MW. Furthermore, the inverters are listed to UL-1741, which is based on the requirements of IEEE 1547. This report recommends that new standards are proposed for utility scale PV plants in order to drive the industry toward the adoption of new inverter specifications, testing, and certification.	**ERSTF**	Not sure if above response is correct or supported. At minimum, ERSTF should track the growth and make recommendations to take action at an appropriate time.	ERSTF will end up getting this, do they agree? ERSTF members will participate in IEEE 1547 team discussions to provide input for the BPS system impact. NERC's MOU with IEEE will handle the process further.
Models for Facility Interconnection Studies Accurate models are required for all generator facilities that are connected to or are planning to connect to the Bulk Electric System (100 kV and higher) regardless of size. Ongoing model revalidation is currently covered by: • MOD-024-1: Verification of Generator Gross and Net Real Power Capability • MOD-025-1: Verification of Generator Gross and Net Reactive Power Capability • MOD-026-1: Verification of Models and Data for Generator Excitation System Functions • MOD-027-1: Verification of Models and Data for Turbine/Governor and Load Control. The ongoing detailed model validation may evolve to cover generator units or generator facilities 75 MVA or larger. This breakpoint covers at least 80 percent of the currently installed generation in North America and matches the NERC Statement of Compliance Registry Criteria, which is approved by FERC.	**No Action**	"No Action" transition category is appropriate.	OK

Summary of Facility Connection Model Grid Code Requirements: Several key features could be recommended for adoption by Transmission Owners • Preliminary model data may be used for the initial feasibility study of a variable generator interconnection project. • The best model available shall be used for the final System Impact Study or Facilities Study. These models can be user-written and require nondisclosure agreements. • The detailed dynamic model must be accurate over the frequency range of 0.1 to 5 Hz. Time constants in the model should not be less than 5 ms. • The detailed dynamics model must have been validated against a physical or type test • Verification of detailed model performance should be confirmed during commissioning to the	**Planning Approaches and Technical Guidelines**	There is minimal support to make FAC-001 prescriptive. The above recommendations can be documented in a technical guidance document for industry.	Planning model vs. as built? Already covered in MOD-032 and MOD-033? SAMS can support the recommendation.
Communications between Variable Generation Plants and Grid Operators Recommendation: The Task 1-3 project team recommends that the basic requirements for communications and control between grid operators and variable generation plants be based on existing policy for conventional generators. • Variable generation plants should send a minimum set of monitoring data to the grid operation via the grid's SCADA network. • Variable generation plants should receive and execute command signals (power limit, voltage schedule, ramp rate limit, etc.) sent from the grid operator via the SCADA network. • Variable generation plants should have trained on-call plant operators that can receive calls from the grid operator 24/7 and immediately execute verbal commands. The plant operators would not need to be located at the plant provided they have secure remote control capability for the plant.	**Planning Approaches and Technical Guidelines**	There is minimal support to make FAC-001 prescriptive. The above recommendations can be documented in a technical guidance document for industry.	Guideline or standard, i.e, can we have a standards that tells a VG to have trained operator on 24/7? OC issue not planning.

Active Power Control Capabilities Recommendations: • Require Curtailment Capability, but Avoid Requirements for Excessively Fast Response: Variable generation can respond rapidly to instructions to reduce power output. In many cases response is faster than conventional thermal or hydro generation. However, there have been cases where proposed grid codes have made excessive requirements for speed of step response to a curtailment order. This is technically challenging and should be avoided. A change (Δ) 10 percent (%)/s for rate of response to a step command to reduce power output is reasonable. This rate of response to step instructions should not be confused with deliberate imposition of ramp rate limits, as discussed next. Active power considerations are not driving reliability requirements at this time. Some conventional generation can reach or even exceed these rates. Most cannot. The project team is not aware of any NERC standards that specify rate of response to re-dispatch commands (of which curtailment is a subset) in this time frame. Typically, plants must respond to economic re-dispatch within minutes. Mechanisms such as markets or other incentives to encourage rapid rate of response from all generating resources should be considered. • Require Capability to Limit Rate of Increase of Power Output.	**ERSTF**	Should say something like ERSTF will determine minimum ramp rates required for essential reliability.	ERSTF will end up getting this, do they agree? No, But the ERSTF discussed and considered this recommendation; however decided it's priudent to pass to Operating Reliability Subcommittee (ORS)
Recommendation to NERC Standard FAC-001-0 Modification: Generator facilities smaller than the 75 MVA threshold—especially variable generation facilities—may experience rapid changes in control performance over their lifetimes due to equipment upgrades and replacements. These changes should be captured in updated models. However, substantial modifications on facilities less than 75 MVA may not be captured by the FAC-001 standard or MOD standards. However, substantial modifications on facilities less than 75 MVA may not be captured by the FAC-001 standard or MOD standards. It is recommended to modify FAC-001-0 to: "R2: The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items: R2.1.1 Procedures for coordinated joint studies of new or substantially modified facilities and their impacts on the interconnected transmission systems."	**ERSTF**	I expect small non-BES generation is being ignored or netted out with load. The ERSTF should track growth of variable generation and determine impacts on reliability	ERSTF will end up getting this, do they agree? No - This will go to Standards Committee or Functional Model Working Group

Recommendation to NERC Standard FAC-001-0 Modification: The following statement be added to the FAC-001-0 standard as an appendix for clarifying R3.1.17: "Preliminary or approximate power flow and dynamic models may be adequate for the preliminary assessment of interconnection impacts, or to represent existing and proposed projects that are not in the immediate electrical vicinity of the facility being studied. However, detailed dynamic (and possibly transient) models for the specific equipment may be needed for the System Impact Study and Facilities Study to represent the facility and other equipment in the electrical vicinity. Generic non-proprietary publicly available models are more appropriate for the NERC model building process covered by existing MOD standards, although validated generic models with specifically tuned parameters may be adequate for interconnection studies. The models for interconnection studies must be acceptable to the Transmission Owner in terms of simulation platform, usability, documentation and performance."	**ERSTF**	This recommendation is too prescriptive and therefore No Action transition is appropriate? It shouldn't be in FAC-001 but should be in a Technical Guidance document	OK , should be covered under individual interconnection requirement. No - This will go to Standards Committee or Functional Model Working Group