NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2015 Winter Review

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RELIABILITY | ACCOUNTABILITY




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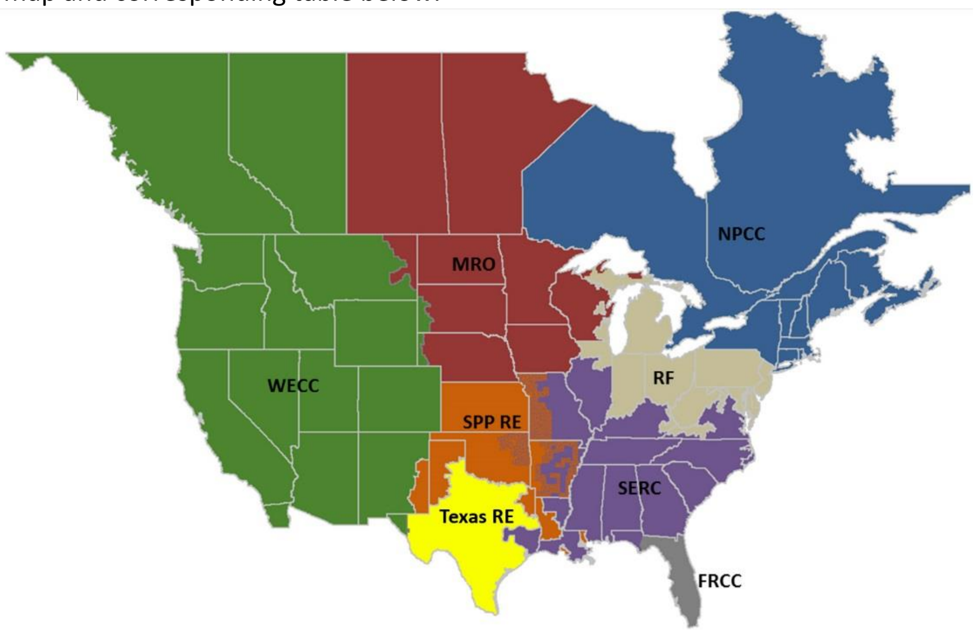
Preface

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

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



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

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

Executive Summary

This report serves as an analysis and comparison of the BPS performance in the winter quarter of 2015 versus previously recorded years, most notably the 2014 polar vortex. It briefly reviews conditions and results from the *2014 Polar Vortex Review*, then shows similar conditions and results from 2015 when extreme winter conditions became comparable.

The winter of 2015 marked the second consecutive year in which extreme cold weather conditions affected North America, primarily the eastern and Midwest portions of the grid. In the first quarter of 2015, North America experienced two notable cold snaps, one from roughly January 5 to January 8, and the other from February 16 to February 20. These cold snaps created conditions similar to those experienced in the January 2014 polar vortex. Several Reliability Coordinator (RC) areas of the BPS experienced near-peak loads on several of these days. These similar conditions create a good benchmark for a comparison to extremes experienced in 2014.

Overall BPS performance during the 2015 cold weather events showed improvements over the winter of 2014. In part, the improvements reflected actions taken by stakeholders as a result of analysis, lessons learned, and implementation of recommendations from what was experienced in 2014 and years prior. While few generation outage rates remained above historical norms in 2015, the ERO continues to emphasize the need for thorough and sustained winter preparation to improve generation performance and close coordination and communication between Generator and System Operators, particularly during peak winter demand periods. In some areas, such as in the Texas regional footprint, the outages above the selected norms showed no correlation between winter preparation and the outages (i.e., they were not related to cold weather conditions).

Temperatures and Peaks

The winter of 2015 was marked by cold temperatures similar to the winter of 2014, with the coldest temperatures experienced during February 2015 throughout the Eastern Interconnection. Numerous cities hit their daily low-temperature records during February 2015. Due to the low temperatures and associated high electricity demand for heating needs, PJM set a new wintertime peak demand record of 143,086 megawatts the morning of February 20, 2015 (hour ending 0800). The new peak record surpassed the previous all-time winter peak of 142,863 MW set January 7, 2014. Although the new record winter peak was set during this time frame, no emergency demand response or any other capacity emergency actions were required. Many other areas also set all-time record winter peaks in 2015.

Generator Performance

Generator performance in January and February of 2015 showed improvement over 2014 with improved overall forced outage rates. PJM reached a new all-time winter peak the morning of February 20, 2015, despite experiencing a regional forced outage rate of 13.4 percent, representing 24,805 MW of generation forced out of service. Although the 2015 winter peak forced outage rates represent an improvement over the 22 percent forced outage rate during the January 7, 2014 peak, the 2015 rates were still above the recently experienced historical winter peak outage rate of between 7 and 10 percent. Similar findings occurred across the Eastern Interconnection. The performance improvements of winter 2015 over 2014 are attributed to steps generation owners and transmission operators initiated after the winter of 2014.

Using data gathered through the Generator Availability Data System (GADS), it was possible to generate equivalent forced outage rates (EFORs) across the first three months of 2015, or the winter quarter. These values are normalized across different fuel types and then used to illustrate the amount of time a generating unit is unavailable relative to its expected availability. When comparing and contrasting system performance from the *2014 Polar Vortex Review* to similar stressful environmental conditions in 2015 as shown in Table A-3, the EFORs provide insight into operational challenges to the reliability and resiliency of the Bulk Electric System during the winter time period.

Introduction

2014 Polar Vortex

In January 2014, the United States and Canada experienced a polar vortex, causing temperatures nationwide that were far below normal. These cold temperatures led to record-setting load demands from the North American BPS. The United States national average temperature of 17.9°F on January 6, 2014, was the lowest since the January of 1997. In the time since 1997, a significant amount of the generating fleet has become fueled by natural gas. Since the BPS had not experienced such low temperatures following this fuel shift, a large number of issues were discovered. Due to these challenges, there was a noticeable disruption in power availability in portions of eastern North America.

Background

The first quarter of 2015 brought about more record-breaking cold temperatures across eastern North America. In both January and February, extreme cold snaps were experienced, creating conditions comparable to the 2014. Table 1 and Figures 1 and 2 illustrate the unexpected differences from temperatures normally experienced during these periods.

During January, the average contiguous U.S. temperature was 33.0°F, 2.9°F above the 20th century average. This ranked as the 24th warmest January in the 1895-2015 record and marked the warmest January since 2012. The February contiguous U.S. temperature was 33.1°F, 0.7°F below the 20th century average and ranking near the median value in the 121-year period of record. The average February maximum (daytime) temperature for the contiguous U.S. was 44.6°F, 0.2°F below average, while the average minimum (nighttime) temperature was 21.7°F, 1.2°F below average.[1]

Table 1: Average vs. Observed Temperatures (Fahrenheit)

	Minneapolis, MN	Chicago, IL	St. Louis, MO	Dallas, TX	Columbus, OH	Indianapolis, IN	Columbia, SC	Washington DC	New York, NY
Avg. High/Low Jan	24/8	31/18	41/23	57/37	36/22	36/20	56/36	43/29	38/27
Observed 5-Jan-15	12/-7	10/-1	26/13	48/26	27/12	14/4	57/37	52/29	49/21
Observed 6-Jan-15	1/-11	12/5	10/-1	62/30	21/12	19/9	60/32	32/24	22/19
Observed 7-Jan-15	8/-5	8/-4	17/5	43/24	13/2	12/-6	48/26	30/14	23/9
Observed 8-Jan-15	-1/-9	20/-7	8/2	39/17	20/-6	20/-7	32/16	26/12	21/8
Avg. High/Low Feb	29/13	35/21	46/27	61/41	41/25	40/24	61/38	47/31	42/29
Observed 16-Feb-15	20/8	19/8	21/8	63/32	10/0	16/6	42/27	20/10	21/3
Observed 17-Feb-15	10/2	22/11	32/7	55/29	19/-4	26/1	39/26	31/17	27/14
Observed 18-Feb-15	2/-9	11/26	26/9	60/31	18/4	17/0	49/25	34/13	33/19
Observed 19-Feb-15	9/-11	7/-5	18/5	61/33	8/-2	9/-5	33/22	21/11	27/8
Observed 20-Feb-15	25/5	20/-1	28/12	70/45	14/-8	18/-6	37/28	22/5	19/2

[1] Weather data and summaries were retrieved from the National Oceanic and Atmospheric Administration at www.noaa.gov.

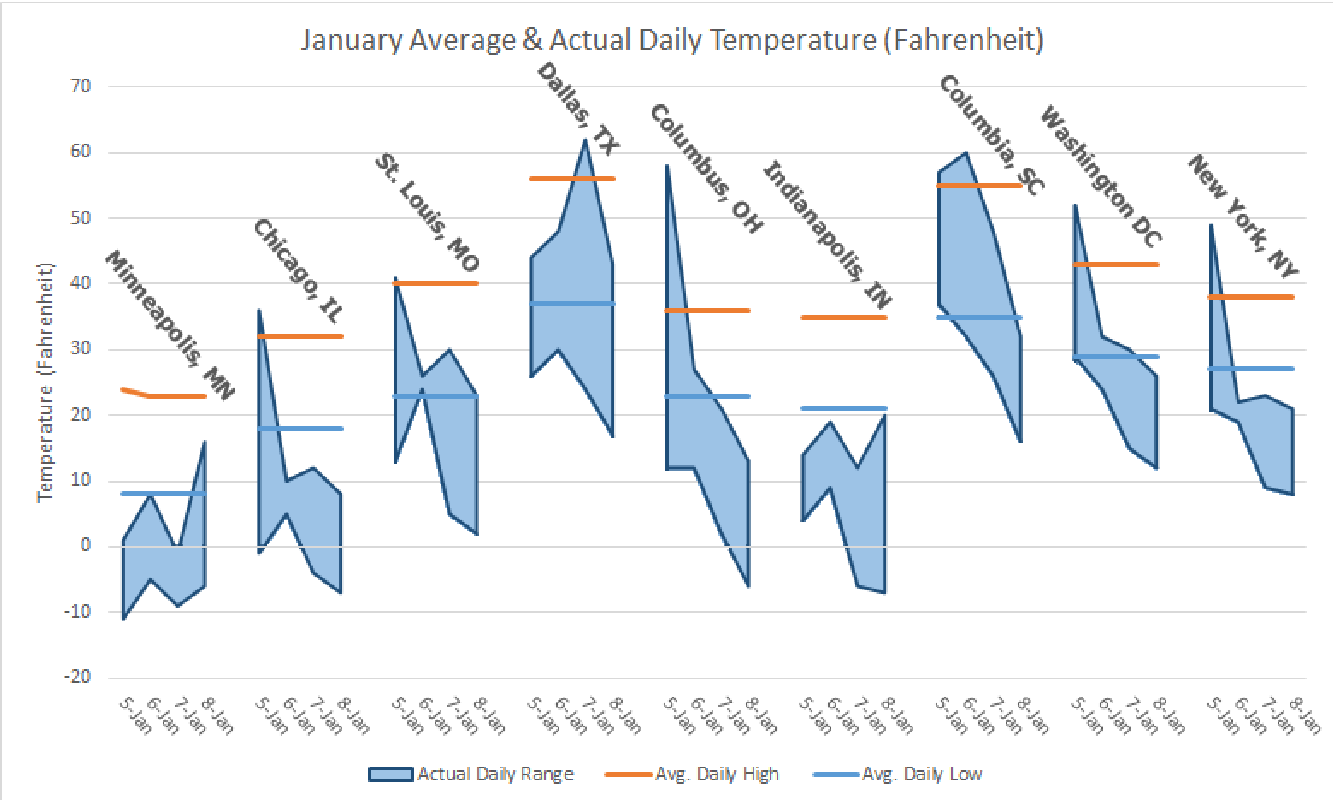


Figure 1: average vs. observed temperatures in January

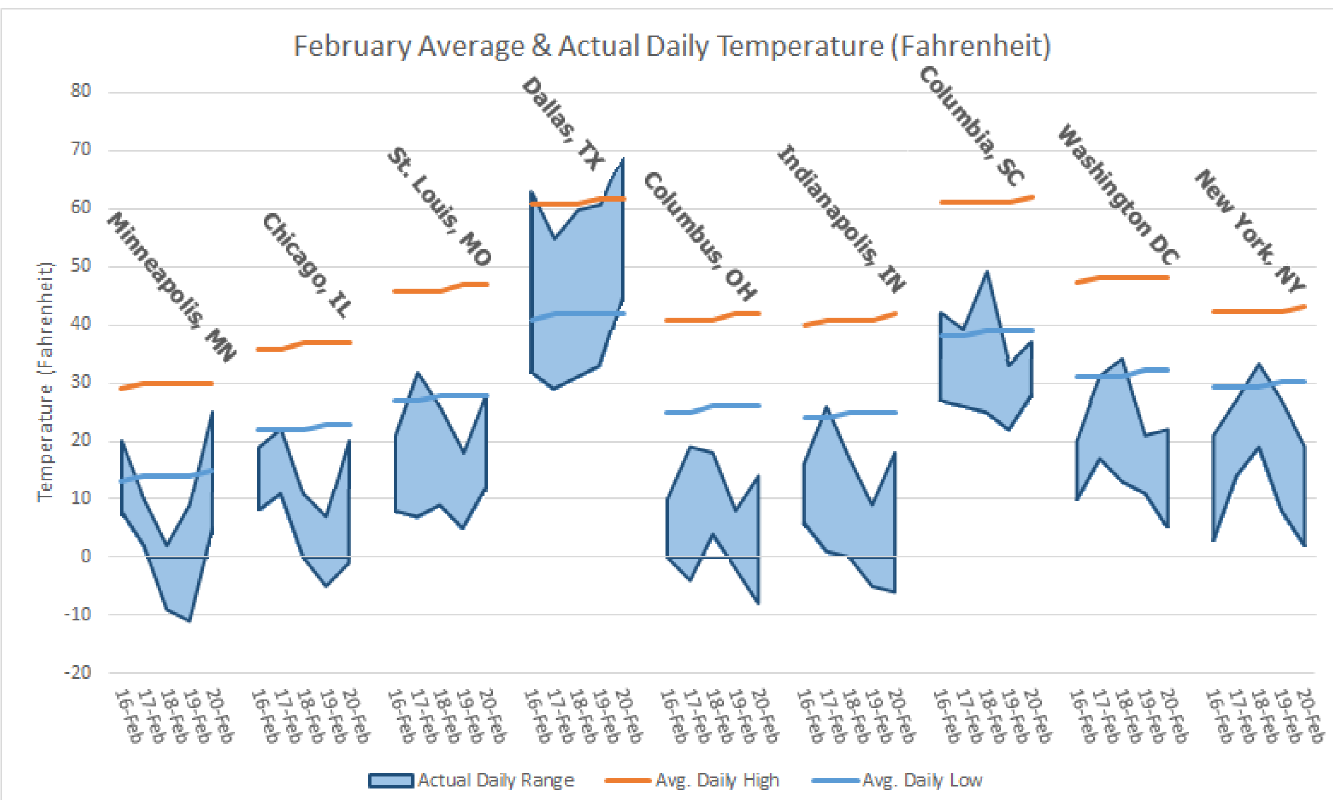


Figure 2: average vs. observed temperatures in February

Section 1 – Method of Analysis

GADS Data Review and Validation

NERC introduced GADS in 1982. GADS data is used to calculate unit availability statistics and to support bulk power trend analysis by providing information on forced outages, maintenance outages, planned outages, and derates.[2] The NERC Board of Trustees (Board) approved mandatory reporting of data to GADS for conventional generating units on August 4, 2011. Renewable generation (e.g., wind and solar) are not part of the mandatory data submittal requirements. The MW size of the conventional units was phased in, with units having a nameplate rating of 50 MW and larger starting January 1, 2012, and those with a nameplate rating of 20 MW and larger starting January 1, 2013. GADS data is collected from all Generator Owners on the NERC Compliance Registry under the NERC Rules of Procedure Section 1600, Request for Data or Information. Generating units less than 20 MW are encouraged to report unit information on a voluntary basis.

NERC collects the equipment information by class of outage and calculates statistics, such as EFOR, by using IEEE Standard 762 definitions, thereby ensuring a high level of confidence that the statistics are calculated in a uniform process using an industry-approved method. Analysis of GADS data provides trend information on forced, maintenance, and planned outages and deratings.

NERC also collects information on fuels burned and fuel-switching activities (e.g., coal to gas, oil to gas, and biofuels to other fuels) that can present challenges during extreme conditions. Since GADS was a voluntary database prior to 2012, analysis of data prior to 2012 provides partial information. Additionally, since units less than 50 MW but greater than 20 MW were not reported to NERC until 2013, analysis of 2012 data may be biased toward larger units. With these factors in mind, NERC examined GADS data to compare the winter 2015 EFOR to the 2014 polar vortex as well as previous years. The complete summary of the data analysis is provided in Appendix A.

GADS also collects additional generation information on a voluntary basis. Examples of this information include reasons for derates, verbal descriptions of outages, and explanatory cause codes. This information is extremely useful in analyzing individual events but provides limited value when calculating trends of performance characteristics.

NERC staff extracted GADS generator outage data for the winter 2015 period and compared it to past periods of GADS data and winter-event-related information from event analysis reports, demand readings, and weather data to develop the following analysis. GADS does not allow direct correlation between outages and equipment problems due to weather, but it provides a point of reference for overall operational availability.

[2] Derating refers to when a generating unit experiences a limit to its power level below maximum capacity.

Section 2 – Correlating Factors

Weather Conditions

Extreme cold snaps occurred during the months of January and February in 2015, setting record lows for cities across eastern North America. These low temperatures often came very close to the temperatures experienced in 2014, with many falling below and almost all being within 10°F of those experienced the previous year. This allows for a near-direct comparison of several factors that contributed to the previous year's challenges. The most prominent of these factors being the storage and transportation of fuels, especially natural gas, updated weatherization programs during severe weather, and awareness of fuel status for all generators.

Peak Power Loads

In times of extreme cold, the demand for electricity generally increases due to various reasons. The cold snaps experienced during early 2015 were no exception, causing higher than normal peak loads across most Regions. In several cases, new peak loads were set on the system within two days of the cold snaps. New, recent[3] peak records were set by both FRCC (42,947MW) and SPP RE (36,995MW) on February 20 and January 8 respectively. The most notable peak was set by PJM (143,086MW) in the RF and SERC Regions, setting a new all-time peak for the second year in a row during the winter. All other listed Regions experienced less extreme conditions with loads within 10 percent of their peaks, most within five percent. Table 2 provides peak loads from the 2014 as well as during the two cold snaps in 2015. Values in dark blue represent peaks set during the 2015 winter season.

[3] The all-time FRCC winter peak load was 52,368 MWs, which occurred on 1/11/2010.

Table 2: Peak Loads during Polar Vortex and 2015 Cold Snaps

	MISO	PJM	NYISO	ISO-NE	South-eastern RC	TVA	VACS RC	SPP	ERCOT	FRCC
2014 Polar Vortex Peaks (% of Polar Vortex Peak)	112,298 100%	142,863* 100%	25,738* 100%	21,453 100%	48,279* 100%	44,285* 100%	50,659* 100%	36,602* 100%	57,277* 100%	35,638 100%
1/5/2015	97,767 87.1%	119,791 83.9%	23,003 89.4%	19,172 90.0%	32,670 67.67%	33,491 75.63%	32,223 63.61%	34,492 94.2%	52,230 91.1%	28,082 78.8%
1/6/2015	103,215 91.9%	122,822 86.0%	23,632 91.8%	20,001 93.9%	37,101 76.85%	33,342 75.29%	36,504 72.06%	32,743 89.5%	48,039 83.9%	28,236 79.2%
1/7/2015	112,095 99.8%	135,649 95.0%	24,648 95.8%	20,394 95.8%	40,115 83.09%	42,272 95.45%	39,919 78.80%	36,152 98.8%	51,343 89.6%	27,488 77.1%
1/8/2015	113,525 101.1%	136,185 95.3%	24,327 94.5%	20,567 96.6%	47,502 98.39%	43,646 98.56%	44,921 88.67%	36,995 101.1%	56,750 99.1%	30,701 86.1%
2/16/2015	102,145 91.0%	134,142 93.9%	23,754 92.3%	20,095 94.3%	32,442 67.20%	35,099 79.26%	38,798 76.59%	31,752 86.7%	47,284 82.6%	25,724 72.2%
2/17/2015	103,845 92.5%	126,217 88.3%	23,397 90.9%	19,541 91.7%	36,615 75.84%	35,961 81.20%	33,612 66.35%	32,193 88.0%	49,040 85.6%	27,691 77.7%
2/18/2015	105,293 93.8%	127,087 89.0%	22,839 88.7%	18,811 88.3%	40,679 84.26%	38,541 87.03%	37,611 74.24%	33,145 91.0%	48,233 84.2%	28,889 81.1%
2/19/2015	108,191 96.3%	140,344 98.2%	24,024 93.3%	19,675 92.4%	43,817 90.76%	43,263 97.69%	44,195 87.24%	33,488 91.5%	44,579 77.8%	35,704 100.2%
2/20/2015	104,135 92.7%	143,086 100.1%	23,245 90.3%	19,574 91.9%	43,941 91.01%	41,090 92.79%	47,340 93.45%	31,456 85.9%	35,821 62.5%	42,947 120.5%
All-Time Winter Peak	113,525 101.1%	143,086 100.1%	25,738* 100%	22,818 107.1% 1/15/2004	48,279* 100%	44,285* 100%	50,659* 100%	36,995 101.1%	57,277* 100%	52,368 146.7% 1/11/2010
Peak Set in 2015	* Set during 2014 Polar Vortex									

Section 3 – System Performance

Polar Vortex Performance

During the 2014 polar vortex, a large number of issues within the BPS occurred due to temperatures near or below the lowest expected temperatures for prolonged periods of time. Although extensive training, preparation, and proper use of emergency procedures and tools severely curtailed the possible outcome, the performance was one that could be improved upon. Over half of the forced outages stemmed from natural gas generators, with MRO and SERC both experiencing unprecedented outages. This was due largely to transportation as natural gas is not conventionally stored on the power generation site. For more detail, the interdependencies of natural gas availability and power generation is discussed at length in the *2014 Polar Vortex Review*.[4] During the 2015 cold weather spikes noted above, the BPS did not experience the difficulties of the prior year. Improved preparations from 2014's lessons learned contributed to these results.

2015 Winter Season Performance

Through the analysis of peak loads and GADS data, it is possible to examine the system's performance overall as well as on a regional scale from a generation perspective. These factors can then be compared to the same data in previous years to see if the system is performing in a consistent, somewhat predictable manner and whether the implemented changes are beneficial or extraneous.

Following the polar vortex in 2014, several recommendations were proposed by the ERO Enterprise as well as the industry in an attempt to improve performance overall with a focus on natural gas. Based on the data that was analyzed (see Table A3), the implementation of these proposals led to a noticeable increase in the natural gas reliability in several Regions and the overall ability to handle high loads in below-average winter conditions. A comparison of peak load values shows that the system experienced near-peak loads in several instances throughout the season. By pairing this data with the data provided by GADS, it is possible to analyze the system's performance comparatively.

Through the use of GADS data, EFOR calculations were performed. These calculations show how often a unit was unavailable when it was intended to operate. For this calculation, it should be noted that if a unit would be unable to start while in reserve shutdown, the unit is considered to be experiencing a U1 outage, causing a negative effect on the end result. Based on these values and in conjunction with peak load values, it is possible to analyze the system's performance. Due to the sample size of only four years, values rising above 125 percent of previous years' calculated maximum outage rate are considered to be noteworthy. GADS does not directly correlate these outages to equipment or fuel problems due to extreme weather conditions, but it provides a point of reference for overall operational availability.

The EFOR for most Regions' coal-fired units was within previously experienced values, with MRO (January, 109 percent), RF (March, 111.4 percent), SERC (January, 113.2 percent), and Texas RE (February, 107.6 percent) somewhat above past averages, but falling within a 125 percent range. However, Texas RE experienced a high of 20.58 percent in March, 129.2 percent of the previous high of 15.93 percent, but winter conditions no longer prevailed in the Region. Breakdowns by Region are shown in Figures A1, A2, and A3.

All Regions experienced natural gas EFOR values lower than previously experienced highs, with most experiencing values higher to those in 2014. On the other hand, the EFOR for SERC's units during all three months of the winter period were nearly half the previously existing low. Figures A4, A5, and A6 provide comparisons.

[4] Full report is located here: Polar Vortex Review.

An analysis of nuclear unit EFORs did not reveal any notable extremes and supports the excellent availability of the nuclear fleet during winter conditions. This was observed in cases of extreme weather in both 2014 and 2015.

Figures A7, A8, and A9 show most hydro and pumped storage within the previously experienced ranges, with NPCC (February, 113.8 percent) and Texas RE (January 103.4 percent, February 103.4 percent, and March 121.6 percent) being somewhat above the past outage levels but still within 125 percent of the past four years. (Hydro capacity is minor within ERCOT and is derated due to drought.) RF experienced values beyond the cited range all three months (January 180.7 percent, February 302.2 percent, and March 712.9 percent). When compared to high values for other Regions; however, only March remains truly prominent. This was due to several of TRE's largest generators losing their transmission outlet due to a bus outage at the connecting substation.

GADS, at present, does not include availability figures for wind resources, which represent a growing portion of the fleet across North America. Anecdotal input from the Regions does not indicate major issues with forecasts of wind output, but there were some impacts to wind production due to blade icing or low temperatures. Accounting for wind availability, and eventually solar generation availability as well, is a priority for enhancing future GADS data, given the planned growth in these type of resources.

Section 4 – Conclusion

Overall system performance during the 2015 cold weather events showed improvements over the winter of 2014 in areas addressed. In part, the improvements reflected actions taken by stakeholders as a result of analysis, lessons learned, and implementation of recommendations from the 2014 experience. While there were only limited generation outage rates remaining above historical norms in 2015, the ERO continues to emphasize the need for sustained thorough winter preparation. It remains evident that this high preparation level is improving generation performance and reinforces the continuing need for close coordination and communication between generator and system operators, particularly during peak winter demand periods.

Generator performance in January and February 2015 showed improvement, with overall forced outage rates better than in January 2014. The performance improvements during the winter 2015 are attributed to steps generation owners and transmission operators initiated after the previous winter.

Observations and Recommendations

The importance of preparation for extreme weather events could be readily observed from the improved unit performance. The following observations and recommendations are based on the analysis of this performance:

- Whenever possible, many generators would start on gas then switch to oil instead of attempting to start on oil.
- Owners started units earlier than expected, due to anticipated colder temperatures, helping to mitigate the risk of taking more time to start.
- Keeping stations in service overnight with a reduced output level was beneficial to ensuring the unit would stay warm and on-line when needed for the peak.
- More thorough testing of the plant and, if applicable, on the alternate fuel proved effective in proactively identify issues.
- Proactive staffing of typically unmanned stations enabled more rapid response.
- In the PJM footprint, many generation units participated in prewinter operational testing. Units that participated in the prewinter operational testing had a lower rate of forced outages compared to those that did not test.[5]
- PJM established a gas-electric coordination team to establish closer coordination with natural gas pipelines and assist PJM dispatch in factoring gas availability data into its cold weather planning and scheduling with generators. PJM dispatch also benefited from improved reporting on gas status by generators.
- Generation facilities across all Regions have indicated that they have reviewed recommendations, implemented recommendations, or both from the *February 2011 Southwest Cold Weather Event Lessons Learned* as well as the *Generator Winter Weather Readiness* guideline.
- Proactive communication and coordination between the RCs and within the RC areas themselves helped ensure appropriate situational awareness was maintained and rapid response was facilitated as needed. At the highest peak periods, PJM issued alerts and warnings, which are designed to increase awareness and readiness for weather conditions. The cold weather alert was the most-frequently issued emergency procedure during January and February. PJM issues a cold weather alert in advance of an actual operating day when forecasted temperatures are 10°F or lower so market participants can prepare for the extreme weather conditions.

[5] 2015 Winter Report. PJM Interconnection, May 13, 2015.

- Once PJM issued a cold weather alert, it reviewed scheduled outages and contacted transmission and generation owners to defer maintenance on an as-needed basis. During the winter of 2015, some transmission owners were able to defer transmission system maintenance once PJM issued the cold weather alert.
- Some ISO/RTOs conducted detailed seasonal fuel assurance surveys to include gas transportation arrangements, starting oil inventories, and oil replacement capabilities.
- Consider implementing a program to periodically review the winter preparedness of generation facility sites. These programs produced tangible benefits in Texas RE by improving generator winter preparation and by the sharing of good industry practices and can be implemented within an individual company, an ISO/RTO, an appropriate Regional Entity, or any combination of these groups.
- Industry should review internal processes to ensure they are ready to take proactive actions to secure the waivers (market, environmental, fuel, etc.) from the appropriate entities.

Appendix A - EFOR

Overview of GADS

GADS was developed by utility designers, operating engineers, and system planners to meet the information needs of the electric utility industry. For this purpose, specific objectives for the GADS program were established: compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment. GADS is not a substitute for the detailed, often unique, data systems typically found at power plants, or for maintenance data programs that record detailed equipment failures and repair techniques. The objectives of the GADS program can be met through the collective effort of participating GADS members, the cooperation in reporting to GADS, and the sharing of information with the industry.

Based on research by the IEEE 762 committee, the boundary between the generator companies and transmission companies is as follows: “A generating unit includes all equipment up to (in preferred order): (1) the high-voltage terminals of the generator step-up (GSU) transformer and the station service transformers; (2) the GSU transformer (load) side of the generator-voltage circuit breakers; or (3) at such equipment boundary as may be reasonable considering the design and configuration of the generating unit.”

An event occurs any time a generating unit’s operating status or capability changes. Four general classifications of events are reported to GADS: outages, deratings, reserve shutdowns, and noncurtailing events. Reporting event data, in addition to performance and design data, provides all the information needed to evaluate generating unit availability. Events data are especially useful since they are often used to do operation and design analysis for specialized units and equipment.

Participation in the GADS program is mandatory for all conventional units 20 MW and larger (as of January 1, 2013). Reporting the level of detail requested in the *GADS Data Reporting Instructions* enables industry analysts to perform detailed, useful analyses.

All units, except hydro and pumped storage units without automatic data recording equipment, are required to report reserve shutdown events. All other events (forced, maintenance, and planned) must be reported.

EFOR Calculations

$$EFOR = \frac{\sum(FOH+EFDH-EFDHRS)}{\sum(FOH+SH+SyH+PH+EFDHRS)} * 100\%$$ [6]

$$EFDH = \frac{DH * SR}{NMC}$$

- EFOR – Sum of all hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours)
- Forced Outage Hours (FOH) – Sum of all hours during forced (unplanned) outages and startup failures
- Equivalent Forced Derated Hours (EFDH) – Sum of derated hours. Includes planned deratings during reserve shutdowns, once transformed into equivalent full outage hours by given equation
- Service Hours (SH) – Sum of all unit service hours
- Synchronous Hours (SyH) – Sum of all hours unit is in synchronous condensing mode[7]
- Pumping Hours (PH) – Sum of all hours the pumped storage unit is in pumping mode
- Equivalent Forced Derated Hours During Reserve Shutdown (EFDHRS) – Sum of EFDHs that occurred during reserve shutdown[8]
- Derating Hours (DH) – Number of hours specified derating is experienced
- Size of Reduction (SR) – Value of derating experienced
- Net Maximum Capacity (NMC) – Maximum capacity the unit can sustain, ignoring ambient conditions and deratings, minus capacity utilized for the unit's station service and/or auxiliary load

Weighted Versus Time-Based Methods for Pooled Statistics

Two methods are used to calculate pooled (grouping) unit statistics for generation:

1. Unweighted (time-based) methods for calculating pooled (grouping) unit statistics.
2. Weighted (capacity-based) methods for calculating pooling (grouping) unit statistics.

When calculating the performance of generating units, either a weighted or unweighted method is used. The unweighted method takes into account only time spent out, so if in a day a 50 MW generator is out for one hour and a 1,000 MW generator is out for one hour, they will have the same impact.

The weighted method takes into account the generating capacity of the unit. So, in the previous example, the 1000 MW generator would impact the resulting statistic 20 times more than the 50 MW generator, despite having the same outage time. Because of this, the unweighted method is commonly used for outages involving single generators or ones of similar size. Due to all generators rating 20 MW and above being included within GADS data, the weighted method is used in this study to accurately display the effects of each outage on the overall system.

[6]Varies from DRI in that; EFDHRS subtracted from numerator due to GADS error

[7] Synchronizing to the BPS frequency

[8] Uses same equation as EFDH for calculation, however is only accounted for during reserve shutdown

WEFOR Equation

This report uses the following equation to weight EFOR values, variables can be found on previous page.

$$\frac{\sum[(FOR + EFDH - EFDHRS) * NMC]}{\sum[(FOH + SH + Synchronous\ Hours + Pumping\ Hours + EFDHRS) * NMC]} * 100\%$$[9]

2014 Polar Vortex Equation Discrepancy

In the *2014 Polar Vortex Review* the following equation was used to weight EFOR values in an attempt to represent the overall system accurately.

$$\frac{\sum EFOR_x * NMC_x}{\sum NMC_y} * 100\%$$

- $EFOR_x$ – The EFOR value for an individual unit
- NMC_x – The NMC for an individual unit
- NMC_y – The sum of the NMCs of a particular group
- Group – refers to which units were calculated for (i.e. WECC Gas Turbine in January)

The equation used in the *2014 Polar Vortex Review* was believed to be an alternate method of calculation at the time, and was used under the assumption that the same results would be achieved. Since then, it has been discovered that while the resulting ratio of values was fairly similar, the actual values could vary an unacceptable amount. This inaccuracy is caused by multiplying the entire EFOR per unit by the NMC of said unit, then dividing the sum of the group by the group's summed NMC. This causes each unit to be improperly weighted as the denominator value is not correctly accounted for. A mathematical example is provided below for reference.

2014 WEFOR:

$$\frac{A_X * B_X + A_Y * B_Y}{B_X + B_Y} = \frac{A_{NX} * B_X}{A_{DX} * B_X + A_{DX} * B_Y} + \frac{A_{NY} * B_Y}{A_{DY} * B_X + A_{DY} * B_Y}$$

2015 WEFOR:

$$\frac{A_{NX} * B_X + A_{NY} * B_y}{A_{DX} * B_X + A_{DY} * B_Y} = \frac{A_{NX} * B_X}{A_{DX} * B_X + A_{DY} * B_Y} + \frac{A_{NY} * B_Y}{A_{DX} * B_X + A_{DY} * B_Y}$$

- A – EFOR
- A_N – EFOR numerator
- A_D – EFOR denominator
- B – NMC

It can be seen by comparing the two equations that, while very similar, the denominator of the 2014 equation is erroneous due to the EFOR denominator components.

[9] Varies from DRI in that; EFDHRS subtracted from numerator due to GADS error.

Analysis of EFOR by Fuel & Region

The following is an analysis of EFOR data for January, February, and March from 2009-2015, separated by fuel and Region. Coal and natural gas are included due to their large contribution to the issues experienced in 2014. Hydro is included as well due to the unprecedented seasonal high EFOR values. As in the *Polar Vortex Review*, FRCC and WECC are not discussed due to the absence of a major cold weather impact. It should be noted that for the calculation of a unit's EFOR, the unit is considered to be experiencing a U1 outage while in reserve shutdown if unable to switch into an active state. This condition leads to an increase in the EFOR numerator. This increase is a possible cause of several high EFOR values as reserve shutdown units that are available remain unaccounted for within the denominator. For this reason, it is advised to look at EFOR values in comparison to previous values for the same fuel type rather than comparing different fuel types.

For most considered methods of generation, calculated values remained within the expected range for all Regions, with most of the new high values being within 125 percent[10] of the pre-existing range. The areas that fell out of 125 percent of the previous range are; NPCC hydro in March, RF hydro in all three months, and Texas RE coal in March. The main contributing factor to NPCC experiencing a high hydro value is due to prolonged freezing near several of the larger generators. RF experienced a high value for all three months due to several of the Region's largest generators being bottlenecked due to a breaker issue and ice. The high coal value experienced by Texas RE in March appears to be due to various reasons unrelated to cold weather.

Coal

Displayed in figures A1, A2, and A3 are the monthly EFORs for January, February, and March, separated by year and Region.

The following Regions experienced coal EFOR values surpassing the previous highs, although most were not statistically significant and no direct correlation between cold weather preparation and performance was discovered:

- MRO experienced a seasonal high value of 8.98 percent in January, surpassing the previous high of 8.12 percent.
- RF experienced a seasonal high value of 14.10 percent in March, surpassing the previous high of 13.72 percent.
- SERC experienced a seasonal high value of 11.49 percent in January, surpassing the previous high of 10.15 percent.
- Texas RE experienced new seasonal high values of 16.43 and 20.58 percent in February and March respectively, both surpassing the previous high of 15.93 percent.
- NPCC experienced the highest EFOR values but did not surpass the high in 2012. No new seasonal lows were experienced.

[10] Acceptable range is applied due to sample size of only four years.

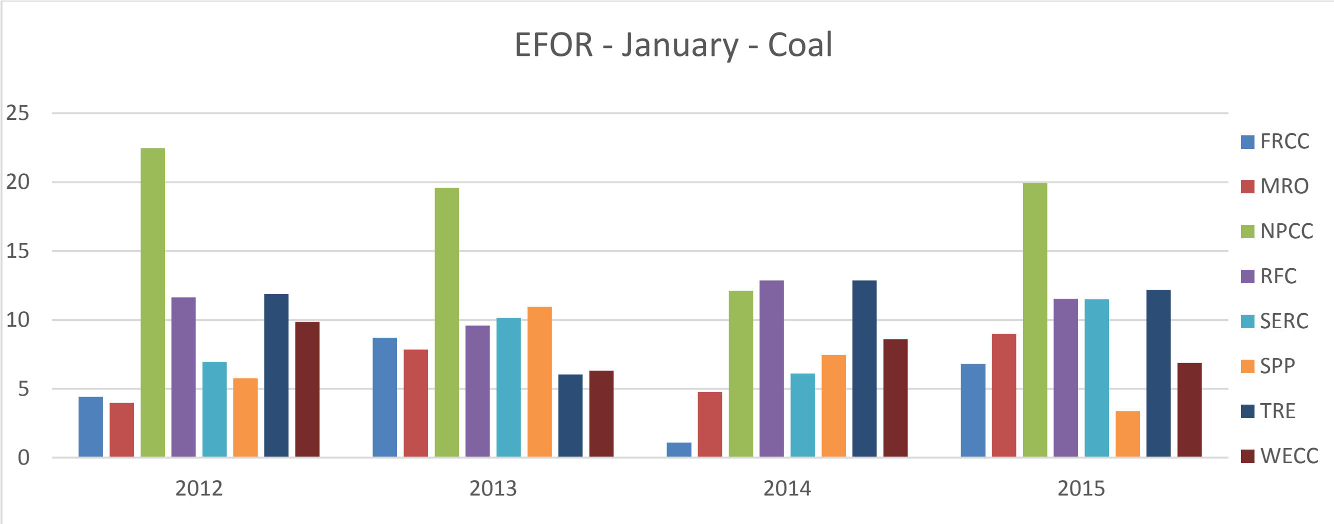


Figure A1: historical EFOR for coal units in January by year and Regional Entity

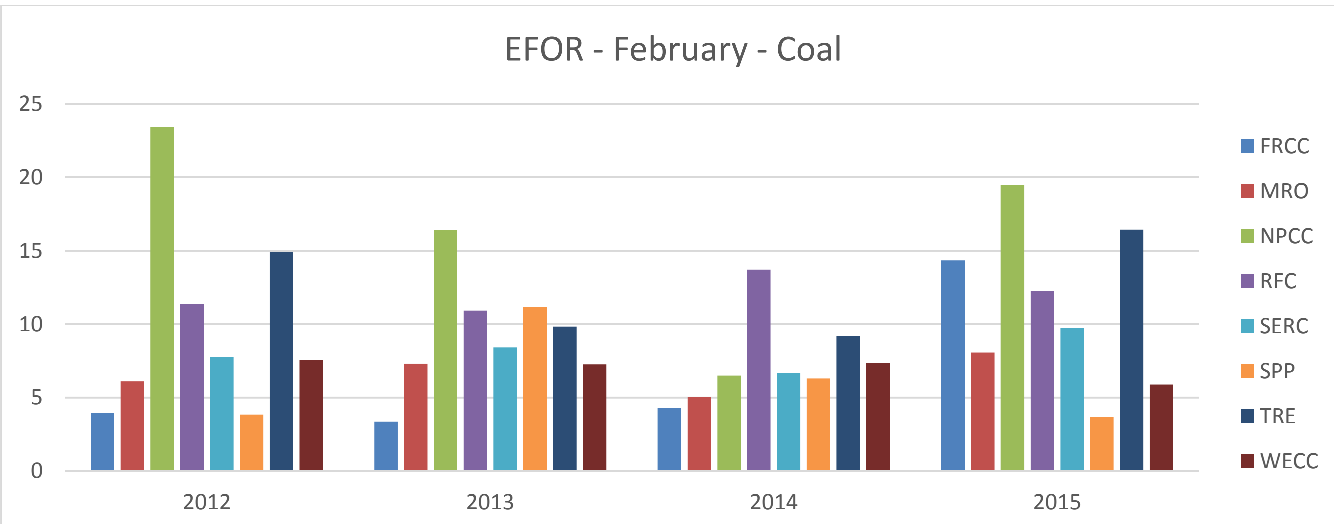


Figure A2: historical EFOR for coal units in February by year and Regional Entity

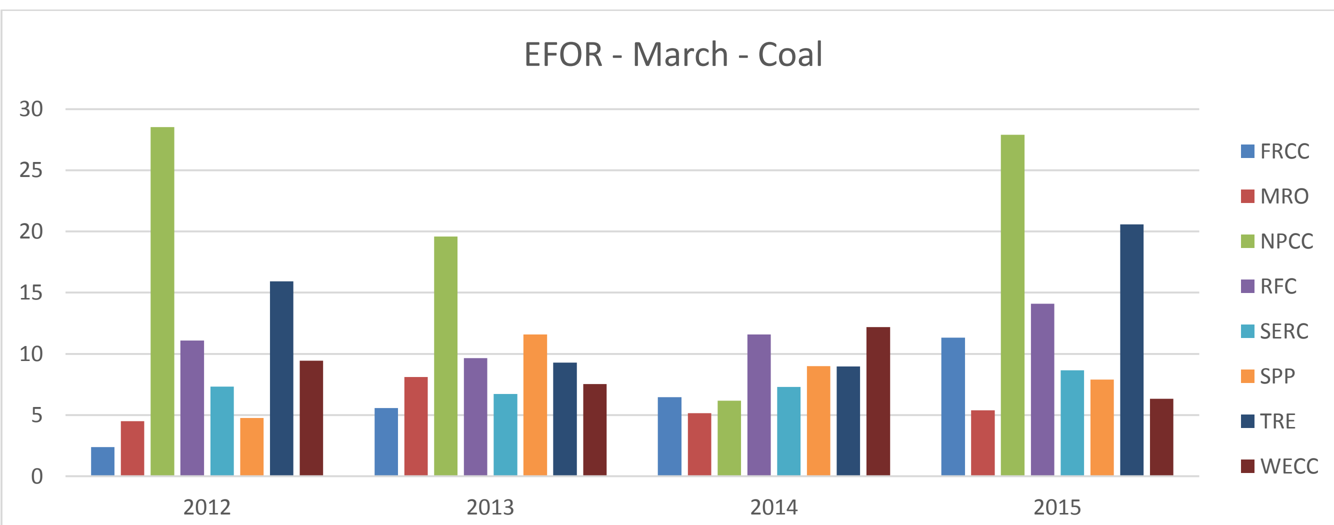


Figure A3: Historical EFOR for Coal Units in March by Year and Regional Entity

Natural Gas

Figures A4, A5, and A6 provide EFOR data for combustion turbine generators using natural gas during the months of January, February, and March, separated by year and Region.

All Regions experienced natural gas EFOR values below their previously existing highs except the following:

- SERC experienced new seasonal low values of 12.62, 11.84, and 12.95 percent in January, February, and March respectively, each at nearly half the previous low of 23.92 percent.

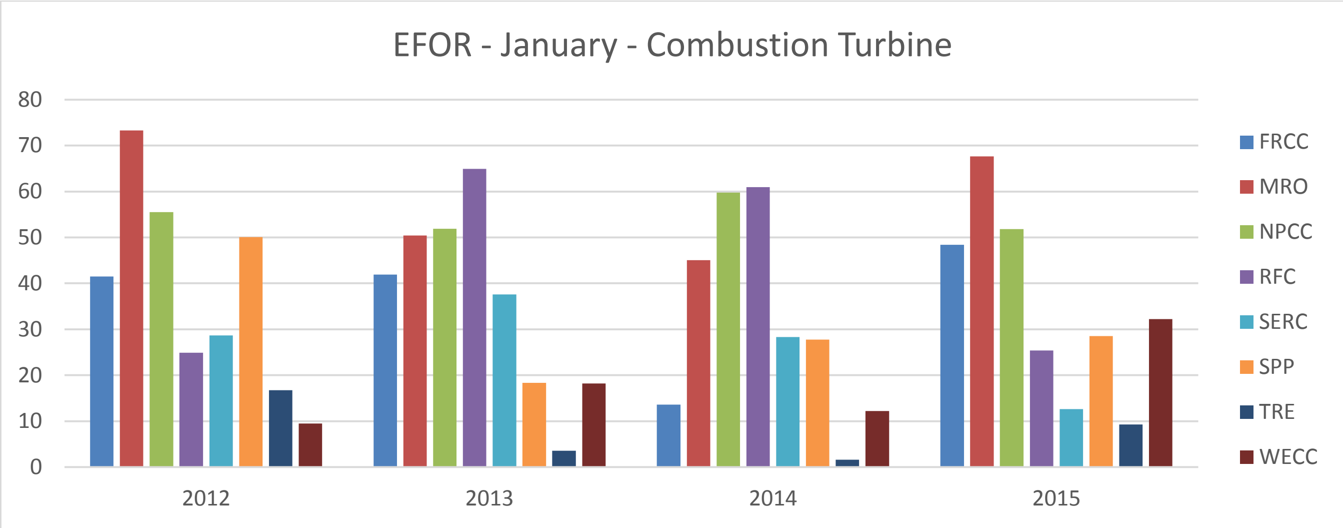


Figure A4: historical EFOR for natural gas units in January by year and Regional Entity

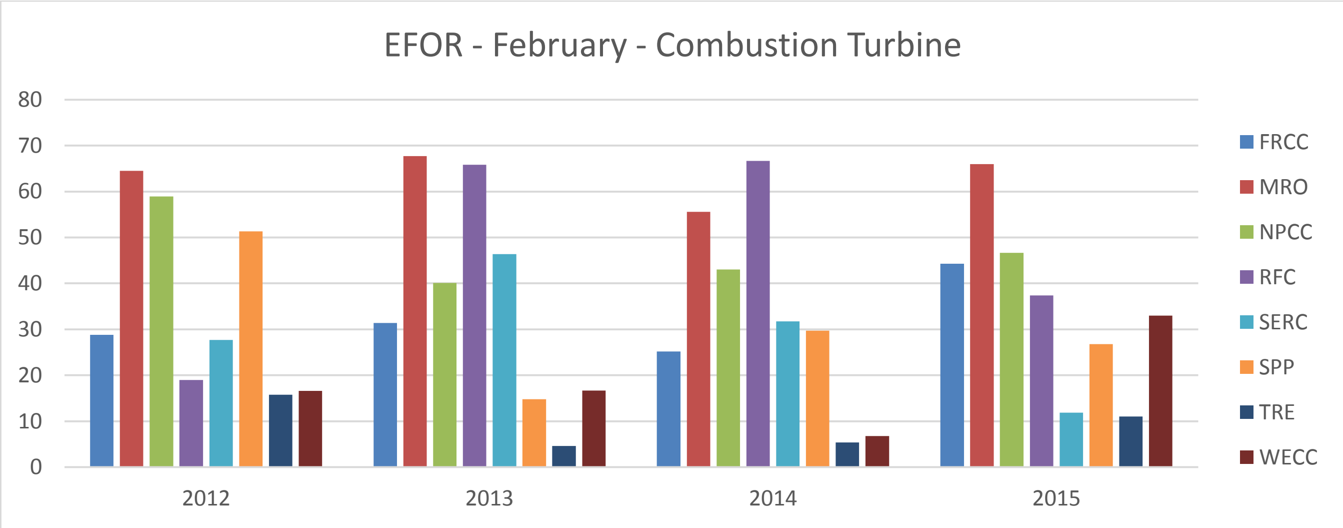


Figure A5: historical EFOR for natural gas units in February by year and Regional Entity

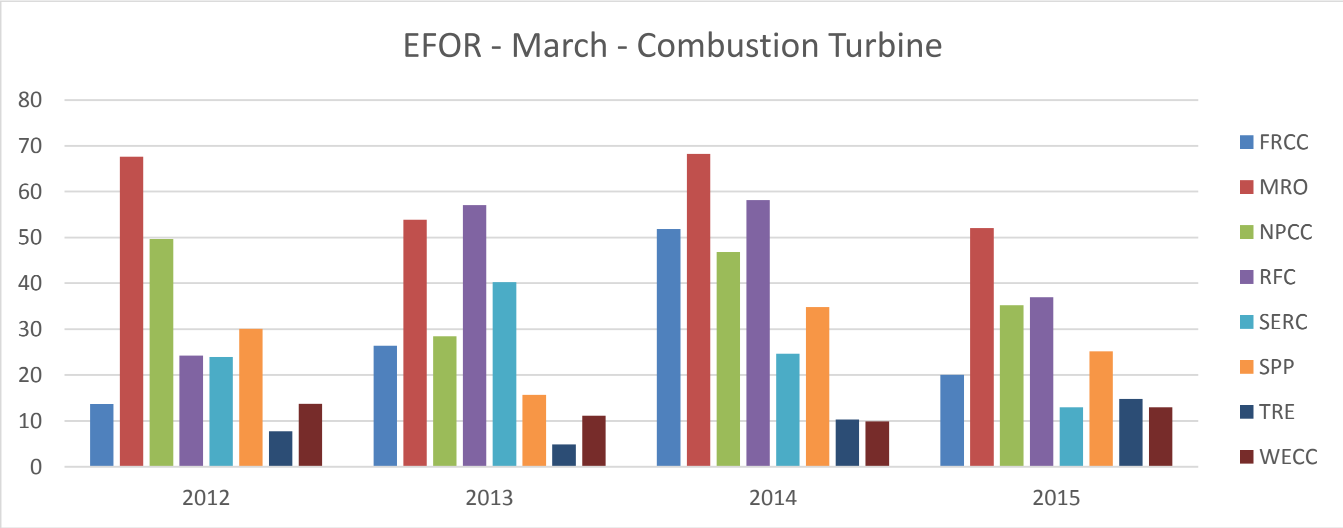


Figure A6: historical EFOR for natural gas units in March by year and Regional Entity

Hydro/Pumped Storage

Figures A7, A8, and A9 show the EFOR for hydro and pumped storage generating units in the months January, February, and March, separated by year and Region.

All Regions experienced hydro and pumped storage EFOR values below their previously existing highs excepting the following. NPCC experienced new seasonal high values of 14.37 and 16.97 percent in February and March respectively, both surpassing the previous high of 12.74 percent. RF experienced new seasonal high values of 9.37, 15.08, and 37.08 percent in January, February, and March respectively, all far surpassing the previous high of 5.44 percent. Texas RE experienced new seasonal high values of 19.42 percent in both January and February as well as 22.84 percent in March, all values surpassed the previous high of 18.79 percent.

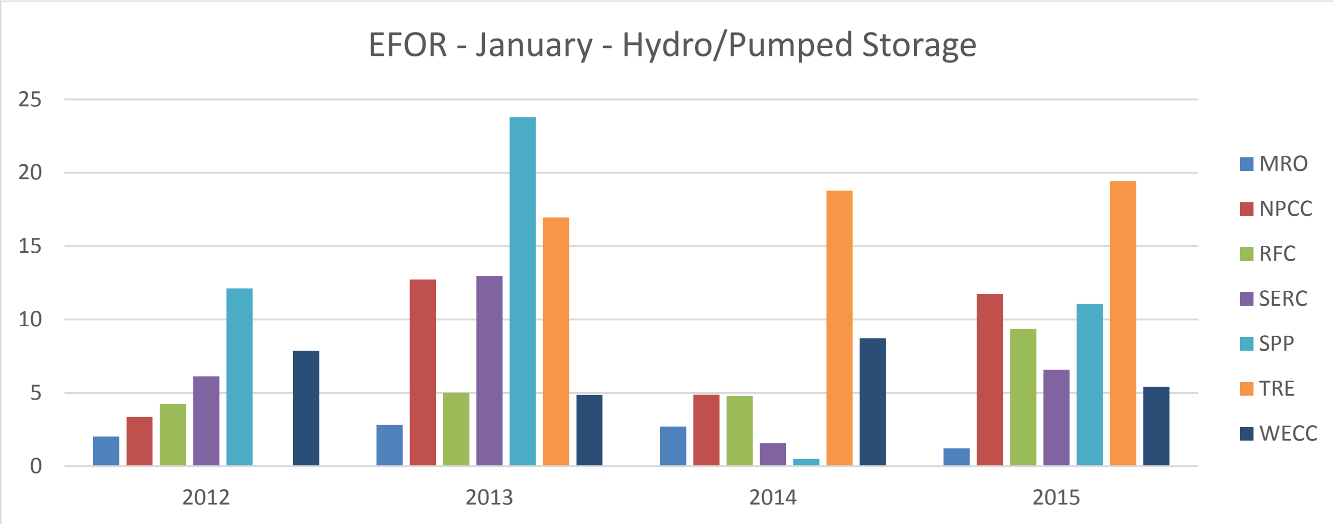


Figure A7: Historical EFOR for Hydro/Pumped Storage in January by Year and Regional Entity

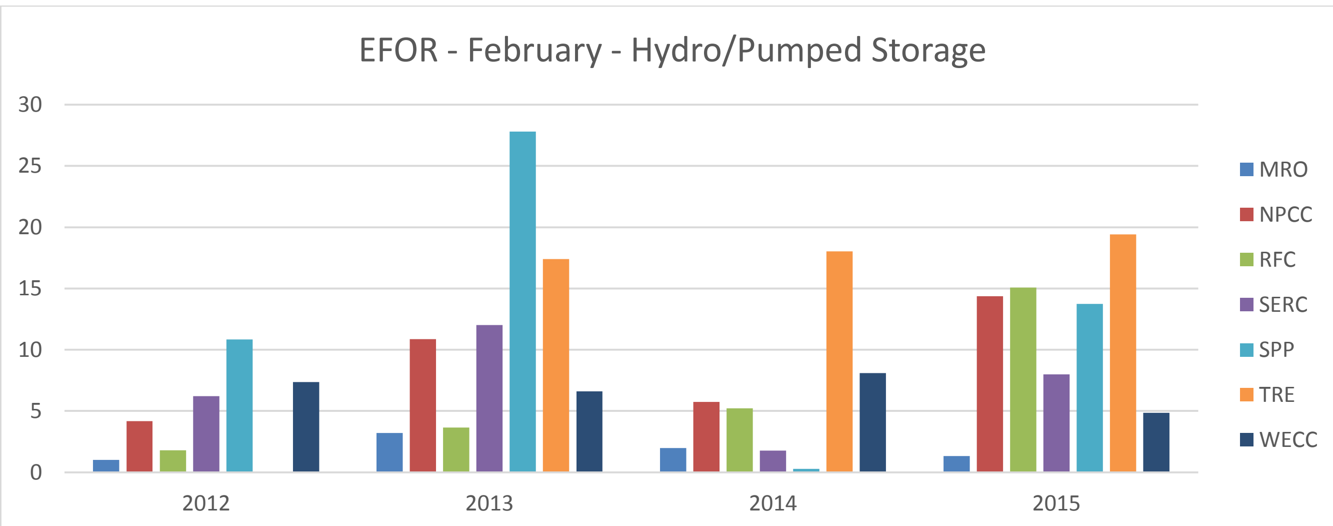


Figure A8: Historical EFOR for Hydro/Pumped Storage in February by Year and Regional Entity

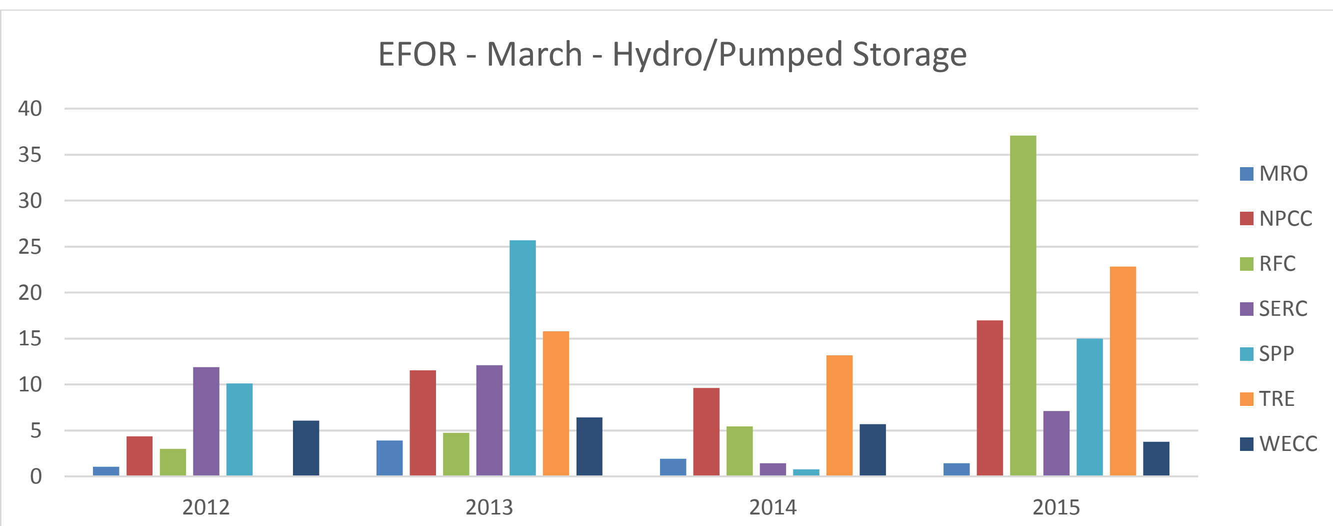


Figure A9: Historical EFOR for Hydro/Pumped Storage in March by Year and Regional Entity

Table A1 provides exact values for all EFORs in discussed Regions for coal, natural gas, hydro, and nuclear in 2014.

Table A1: 2014 EFOR Range by Regional Entity and Fuel Type

Region	Fuel	Previous Seasonal Low	Jan 2014 High	Feb 2014 High	Mar 2014 High	Previous Seasonal High
MRO						
	Coal	3.98%	4.76%	5.04%	5.15%	8.12%
	Natural Gas	50.42%	45.04%	55.59%	68.24%	73.29%
	Hydro	1.01%	2.71%	1.98%	1.92%	3.90%
	Nuclear	11.52%	10.10%	3.05%	3.25%	13.40%
NPCC						
	Coal	16.41%	12.12%	6.50%	6.18%	28.54%
	Natural Gas	28.43%	59.76%	43.04%	46.83%	58.95%
	Hydro	3.36%	4.89%	5.75%	9.63%	12.74%
	Nuclear	2.47%	1.09%	0.73%	4.51%	7.56%
RF						
	Coal	9.61%	12.86%	13.72%	11.58%	11.65%
	Natural Gas	19.01%	60.95%	66.68%	58.13%	65.83%
	Hydro	1.79%	4.77%	5.21%	5.44%	5.01%
	Nuclear	0.53%	3.33%	0.83%	0.93%	1.50%
SERC						
	Coal	6.73%	6.11%	6.68%	7.30%	10.15%
	Natural Gas	23.92%	28.34%	31.72%	24.70%	46.36%
	Hydro	6.13%	1.58%	1.76%	1.43%	12.97%
	Nuclear	0.51%	2.73%	0.02%	1.98%	4.13%
SPP						
	Coal	3.83%	7.46%	6.31%	7.00%	11.58%
	Natural Gas	14.78%	27.76%	29.71%	34.80%	51.34%
	Hydro	0.29%	0.50%	0.29%	0.75%	27.81%
TRE						
	Coal	6.05%	12.86%	9.19%	8.96%	15.93%
	Natural Gas	3.56%	1.65%	5.36%	10.35%	16.72%
	Hydro	0.00%	18.79%	18.02%	13.17%	18.79%
	Nuclear	22.72%	3.94%	0.08%	0.00%	17.41%
Seasonal Low	Seasonal High			SPP Nuclear excluded due to single unit, FRCC Hydro N/A		

Table A2 provides exact values for all EFORs in discussed Regions for coal, natural gas, hydro, and nuclear in 2015.

Table A2: 2015 EFOR Range by Regional Entity and Fuel Type						
Region	Fuel	Previous Seasonal Low	Jan 2015 High	Feb 2015 High	Mar 2015 High	Previous Seasonal High
MRO						
	Coal	3.98%	8,98%	8.06%	5.37%	8.12%
	Natural Gas	45.04%	67.64%	65.96%	52.00%	73.29%
	Hydro	1.01%	1.24%	1.33%	1.44%	3.90%
	Nuclear	3.05%	0.00%	0.00%	9.87%	13.40%
NPCC						
	Coal	6.18%	19.95%	19.46%	27,89%	28.54%
	Natural Gas	28.43%	51.82%	46.62%	35.19%	59.76%
	Hydro	3.36%	11.75%	14.37%	16.97%	12.74%
	Nuclear	0.73%	1.42%	7.56%	4.02%	7.56%
RF						
	Coal	9.61%	11.55%	12.26%	14.10%	13.72%
	Natural Gas	19.01%	25.42%	37.36%	36.98%	66.68%
	Hydro	1.79%	9.37%	15.08%	37.08%	5.44%
	Nuclear	0.53%	0.74%	1.41%	2.55%	3.33%
SERC						
	Coal	6.11%	11.49%	9.75%	8.65%	10.15%
	Natural Gas	23.92%	12.62%	11.84%	12.95%	46.36%
	Hydro	1.43%	6.57%	7.99%	7.10%	12.97%
	Nuclear	0.02%	0.50%	2.43%	1.48%	4.13%
SPP						
	Coal	3.83%	3.37%	3.68%	7.90%	11.58%
	Natural Gas	14.78%	28.54%	26.81%	25.20%	51.34%
	Hydro	0.29%	11.08%	13.73%	14.98%	27.81%
TRE						
	Coal	6.05%	12.20%	16.43%	20.58%	15.93%
	Natural Gas	1.65%	9.32%	11.03%	14.77%	16.72%
	Hydro	0.00%	19.42%	19.42%	22.84%	18.79%
	Nuclear	0.00%	0.00%	0.00%	0.03%	26.94%
Seasonal Low	Seasonal High	Seasonal High >125% Previous High		SPP Nuclear excluded due to single unit, FRCC Hydro N/A		

Table A3 provides a side by side comparison of high and low EFORs for 2014 vs 2015 by Region for coal, natural gas, hydro, and nuclear.

Table A3: 2014 vs 2015 EFOR Comparison

Region	Fuel	2014 Low	2015 Low	2014 High	2015 High
MRO					
	Coal	4.76%	5.37%	5.15%	8.06%
	Natural Gas	45.04%	52.00%	68.24%	67.64%
	Hydro	1.92%	1.24%	2.71%	1.44%
	Nuclear	3.05%	0.00%	10.10%	9.87%
NPCC					
	Coal	6.18%	19.46%	12.12%	19.95%
	Natural Gas	43.04%	35.19%	59.76%	51.82%
	Hydro	4.89%	11.75%	9.63%	16.97%
	Nuclear	0.73%	1.42%	4.51%	7.56%
RF					
	Coal	11.58%	11.55%	13.72%	14.10%
	Natural Gas	58.13%	25.42%	66.68%	37.36%
	Hydro	4.77%	9.37%	5.44%	37.08%
	Nuclear	0.83%	0.74%	3.33%	2.55%
SERC					
	Coal	6.11%	8.65%	7.30%	11.49%
	Natural Gas	24.70%	11.84%	31.72%	12.95%
	Hydro	1.43%	6.57%	1.76%	7.99%
	Nuclear	0.02%	0.50%	2.73%	2.43%
SPP					
	Coal	6.31%	3.37%	7.46%	7.90%
	Natural Gas	27.76%	25.20%	34.80%	28.54%
	Hydro	0.29%	11.08%	0.75%	14.98%
TRE					
	Coal	8.96%	12.20%	12.86%	20.58%
	Natural Gas	1.65%	9.32%	10.35%	14.77%
	Hydro	13.17%	19.42%	18.79%	22.84%
	Nuclear	0.00%	0.00%	3.94%	0.03%