



2011 State of the Interconnection

Western Electricity Coordinating Council

By

WECC Staff

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Preface

The Western Electricity Coordinating Council (WECC) is the Regional Entity responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection. In addition, WECC provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.

WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). WECC's service territory (yellow portion of the map below) extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.



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Introduction

The mission of the Western Electricity Coordinating Council (WECC) is to promote and foster a reliable and efficient Bulk Electric System. To help accomplish this mission, WECC's Reliability Policy Issues Committee (RPIC) established a vulnerabilities initiative to evaluate risks to system reliability within the Western Interconnection. WECC staff has provided RPIC with periodic updates for the ongoing analyses of data and trends for various system events, real-time performance measures, compliance violations, and planning observations. This report was developed and designed to provide those same topical updates, but at the annual-level scale and to a larger audience.

WECC developed the 2011 State of the Interconnection report to provide a high-level overview of the data collected for 2011 in the Western Interconnection. This report is intended to:

1. provide 2011 data at a high level;
2. provide associated historical data;
3. provide an analysis of the 2011 and other historical data as an indicator of the current state of the Western Interconnection;
4. provide observations that help connect the state of the Interconnection today to the future; and
5. provide recommendations, where possible, for addressing threats to reliability and gaps in the data and analysis process.

2011 State of the Interconnection

In 2011, outage rates in the Western Interconnection remained relatively unchanged throughout the year, with the exception of two major system events. On February 1-5, 2011, there was a weather-related event in the El Paso Electric service territory and on September 8, 2011, the Pacific Southwest encountered more than 30 outages. Despite these major events, the outage rates remained within the average range for the three-year period evaluated.

No apparent correlation was found with transmission outage rates and standards violation trends in 2011. However, while standards requirements violations were relatively stable, the number of standards requirement violations with severe or moderate impact on reliability for 2011 was significantly lower than in 2008, continuing a four-year downward trend.

The power supply for the Western Interconnection in 2011 met the need for actual demand, with a Reserve Margin of 28.2 percent for summer and 34.8 percent for winter. The summer-peak load for the Interconnection was 152,211 MW and for winter-peak it was 131,471 MW. It is important to note that some parts of the Western Interconnection are summer-peaking, while others are winter-peaking.

With the increasing focus on renewable generation resources in the West, this is most notable with the installation of 2,957.6 MW of wind generation capacity, or nearly half of the total installed capacity for 2011. Other installations included: 95 MW biomass, 835 MW coal, 1,929.8 MW gas, 129.5 MW geothermal, 3 MW hydro, and 208.8 solar for a total of 6,158 MW installed capacity. The total retirements included 491.5 MW of combined coal, gas, and hydro generation.

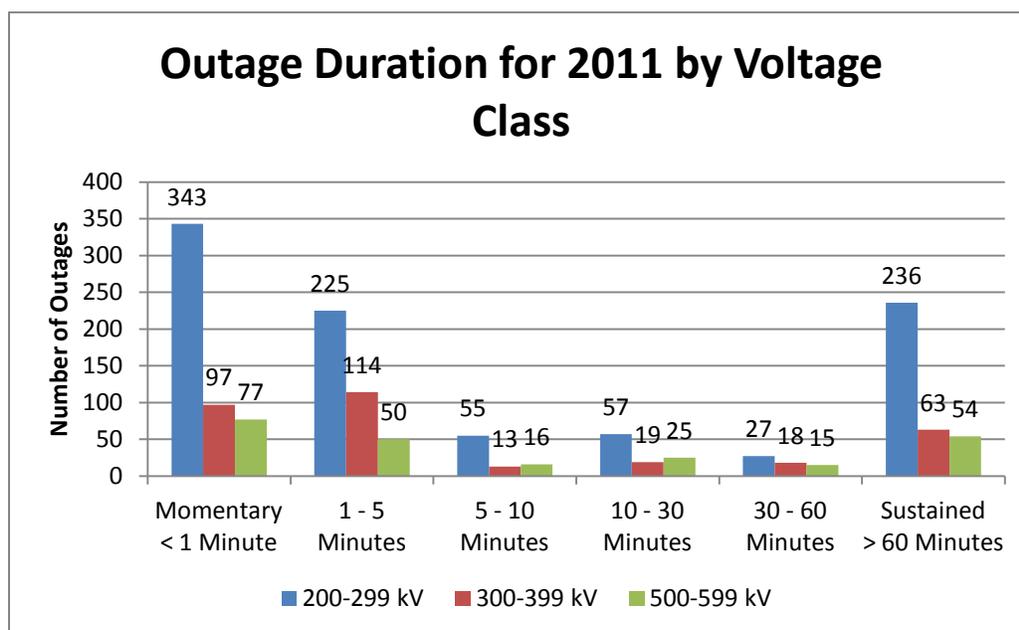
Outages

2011 Transmission Outages

WECC collects outage and transmission inventory data from 64 transmission organizations throughout the Western Interconnection for transmission elements operated at 200 kV and above. The outage data is separated into voltage classes, outage duration (momentary or sustained), and outage cause to illustrate the types of outages occurring on the Bulk Electric System.

Compared to previous years, 2011 outage rates remained relatively unchanged in spite of a major event in September that alone added more than 30 outages to the total. Figure 1 summarizes the entire outage dataset for 2011 in a histogram distinguished by outage duration for the three voltage classes. Importantly, the majority of the outages during the 2011 period were either momentary (those lasting less than one minute) or sustained (those lasting more than 60 minutes).

Figure 1: Frequency of Outage Duration 2011



The Western Interconnection is the largest North American Region at about 1.8 million square miles, with a population of 78 million people. Table 1 and Table 2 present the existing transmission line circuit miles, by voltage type. There are a total of 122,129 linear miles of transmission circuits above 100 kV. This amounts to 8.27 feet of transmission circuits for every person living in the Western Interconnection.

Table 1: Transmission Line Circuit Miles - AC Voltage (kV)

Transmission Line Circuit Miles - AC Voltage (kV)							
AC Voltage	100-120	121-150	151-199	200-299	300-399	400-599	Total AC Miles 120,385
Line Miles	27,845	16,616	3,475	41,311	10,146	20,992	

Table 2: Transmission Line Circuit Miles - +/- DC Voltage (kV)

Transmission Line Circuit Miles - ± DC Voltage (kV)					
DC Voltage	200-299	300-399	400-599	600+	Total DC Miles 1,744
Line Miles	147	0	1,333	264	

Table 3 presents the 2011 summary outage rates for the transmission voltage classes separated by momentary and sustained outage values, per circuit and per 100 miles. There are more per circuit outages in the 300–400-kV range for both momentary and sustained outages than for the other two voltage ranges combined.

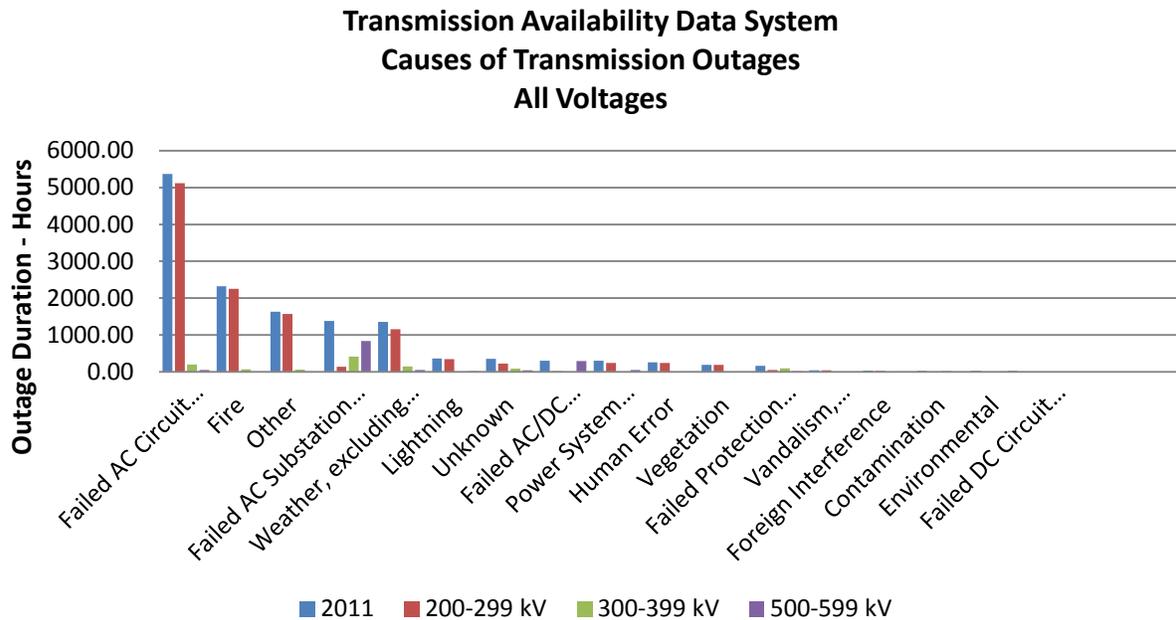
Table 3: 2011 Momentary and Sustained Outages

2011 Voltage Range	Momentary Outages		Sustained Outages	
	Per Circuit	Per 100 Miles	Per Circuit	Per 100 Miles
500-600 kV	0.29	0.40	0.59	0.84
300-400 kV	0.63	0.89	1.48	2.09
200-300 kV	0.20	0.74	0.35	1.29

Figure 2 illustrates the total number of sustained transmission outages for 2011 by NERC Outage Cause Code. Sustained outages were believed to be a bigger threat to reliability, so momentary outages were omitted from this analysis. When looking at the individual voltage classes, the 200–299-kV range makes up the majority of outage duration for 2011 overall. For 2011, Failed AC Circuit Equipment contributed to the largest outage duration and includes overhead or underground equipment outside the substation fence: protective relays, associated communication systems, voltage- and current-sensing devices, station batteries, and DC control circuitry. “A circuit breaker, Transformer, and their associated disconnect switches are not considered part of the AC Circuit....”¹

¹ Transmission Availability Data System (TADS) [Definitions](#)

Figure 2: Causes of Transmission Outages for 2011, All Voltages



Historical Transmission Outage Data

Figure 3 summarizes the entire outage dataset for 2008 through 2010 in a histogram distinguished by outage duration for the three voltage classes. Importantly, the majority of the outages during this three-year period were either momentary (those lasting less than one minute) or sustained (those lasting more than 60 minutes).

Figure 3: Number of Outages Categorized by Duration for 2008-2010

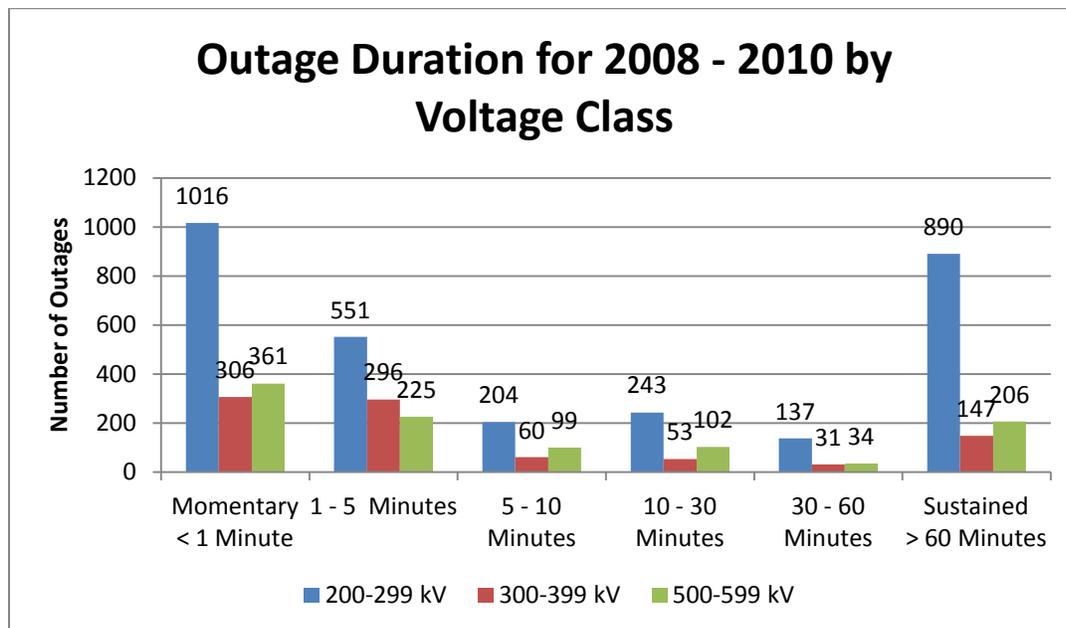


Figure 4 illustrates the total number of sustained transmission outages, from 2008 to 2010, by Outage Cause Code. Sustained outages were believed to be a bigger threat to reliability, so momentary outages were omitted from this analysis. When looking at the total of all three voltage classes, the overall outage rate was relatively consistent for all

three years of data, with a large amount of outage durations in the categories of “Momentary” and “More Than 60 Minutes.” Overall, failed AC Substation Equipment contributed to the largest outage duration over the three-year period. Failed AC Substation Equipment included equipment inside the substation fence: transformers and circuit breakers, but not protection system equipment.

Figure 4: Causes of Transmission Outages 2008-2010, All Voltages

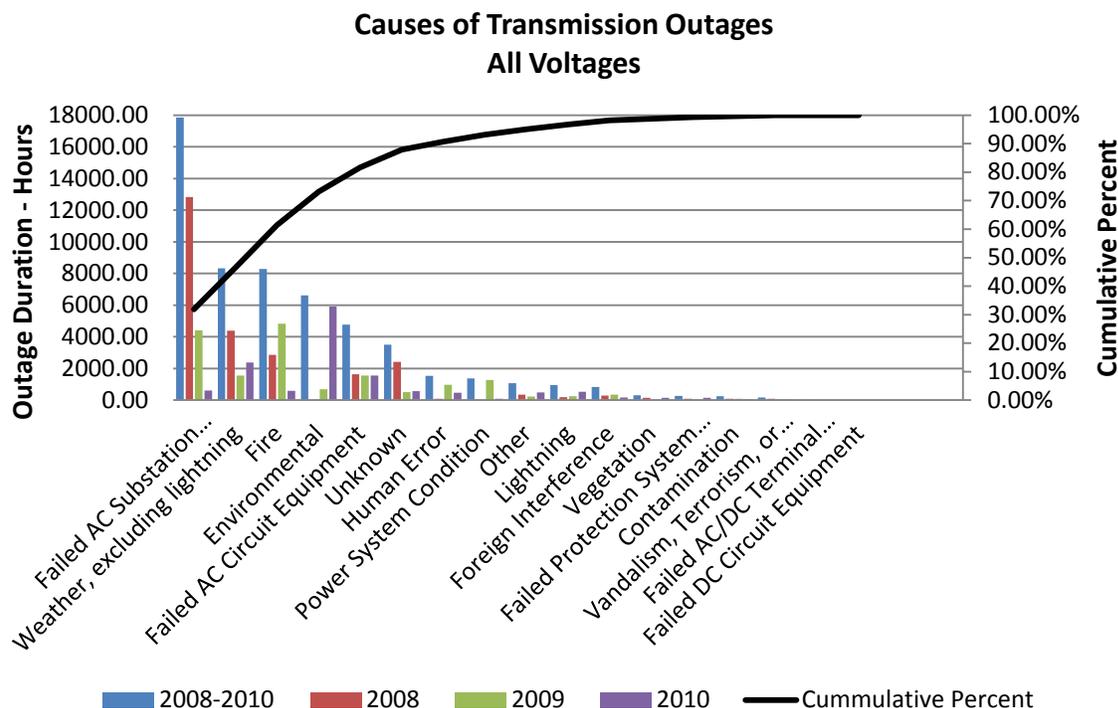


Table 4 presents the outage rates for the transmission voltage classes separated by momentary and sustained outage values, per circuit and per 100 miles, for the average of the data gathered in 2008, 2009, and 2010 combined.

Table 4: 2008-2010 Average Momentary and Sustained Outages

2008-2010 Avg.	Momentary Outages		Sustained Outages	
	Per Circuit	Per 100 Miles	Per Circuit	Per 100 Miles
500-600 kV	0.47	0.65	0.83	1.13
300-400 kV	0.62	0.80	1.35	1.75
200-300 kV	0.21	0.76	0.42	1.52

2011 Event Analysis

During 2011, there were 93 reportable events where NERC Brief Reports were submitted. An event analysis was prepared for eight of those events. Of these 93 events, 66 were classified Category 1, 25 were Category 2, one was Category 3, and 1 was Category 4.² Events are prioritized into one of five categories based on level of

² A description of the different categories is included in the “[ERO Event Analysis Process Document – Appendix E](#)” available on the NERC website.

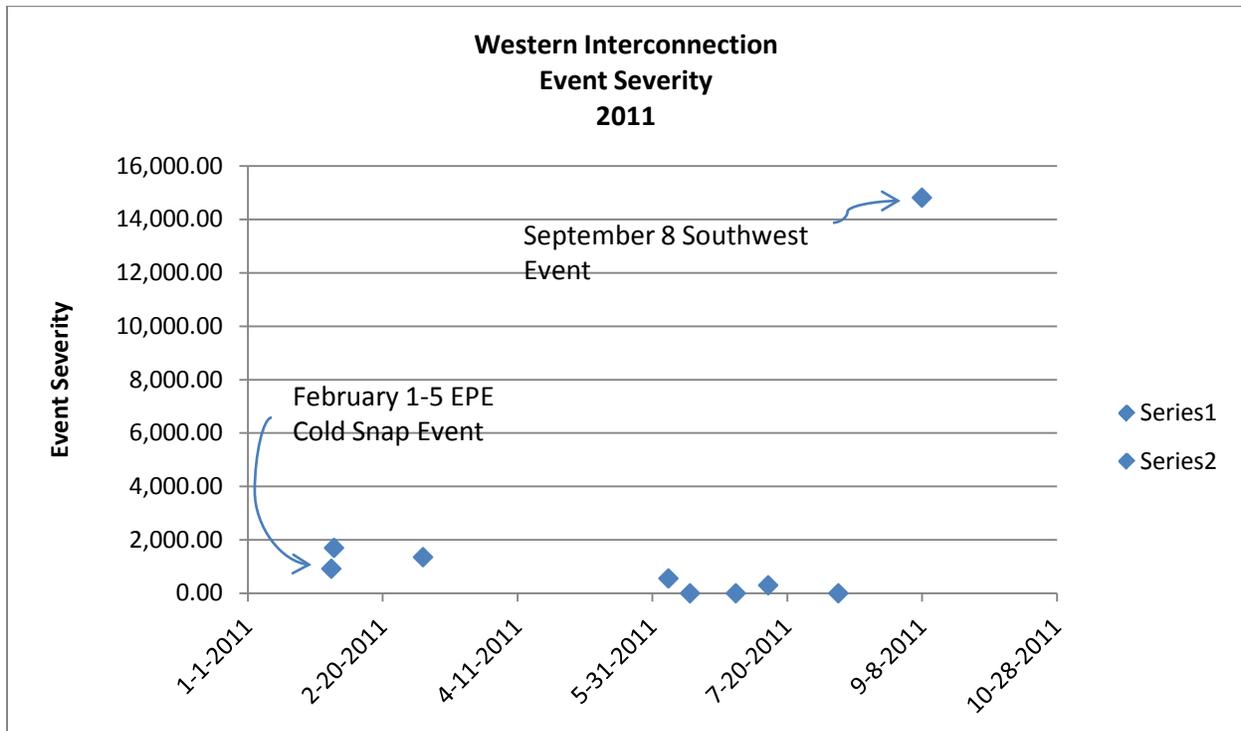
significance and impact on the interconnected system, with Category 5 being the most severe.

Of particular interest during 2011 are the following two events. The first is a Category 2 event that occurred in February in the El Paso Electric service (EPE) territory. While no transmission was affected, sustained record low temperatures and severe wind effects caused the loss of a significant amount of local generation, impacting EPE's load serving capability. Four separate instances of controlled shedding of firm load, impacting approximately 100,000 customers, occurred over the duration of the event. This preemptive action effectively prevented a blackout of the EPE system as well as any failures that could have cascaded into the Interconnection.

The second is a Category 4 event that occurred in September and affected portions of Arizona, southern California and northern Baja California. Across an 11-minute time frame following the loss of a 500-kV line, a system disturbance occurred leading to cascading outages and causing more than seven thousand MW of firm load to be interrupted in the Pacific Southwest, impacting approximately 2.7 million customers. On May 1, 2012 the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) published the report "Arizona-Southern California Outages on September 8, 2011." The report can be downloaded from the [NERC website](#).

To compare the severity of different events, a review of the event causes listed in the event analysis information was performed. For each reportable event in 2011 that was analyzed, event severity was calculated by summing the load and generation loss. This number was then plotted for each reported event in Figure 6. Even though a WECC event analysis was not performed for the September 8, 2011 event, generation and load losses were summed and this value was then added to the chart to get an idea of the severity of this event compared to the other eight events that occurred in 2011 for which an event analysis was prepared.

Figure 5: Event Severity for 2011



Historical Event Analysis Data

To compare the severity of different events, a review of the event causes listed in the event analysis information was performed. For each reportable event from 1999 through 2010 that was analyzed, event severity was calculated by summing the load and generation loss. This number then was plotted for each reported event in Figure 6. The trend line shown in the figure indicates a decrease in event severity over the period.

Figure 6: Event Severity for 1999-2010

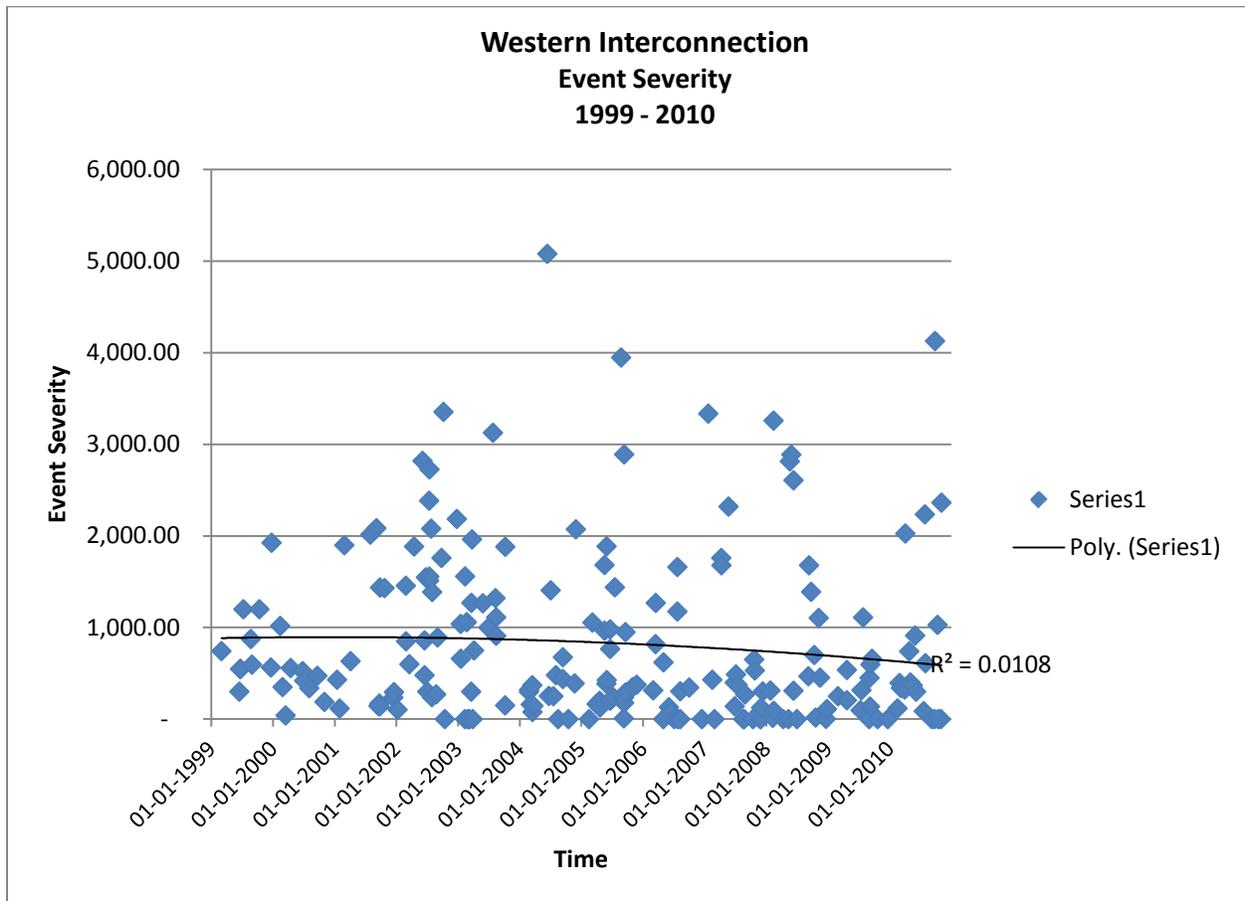
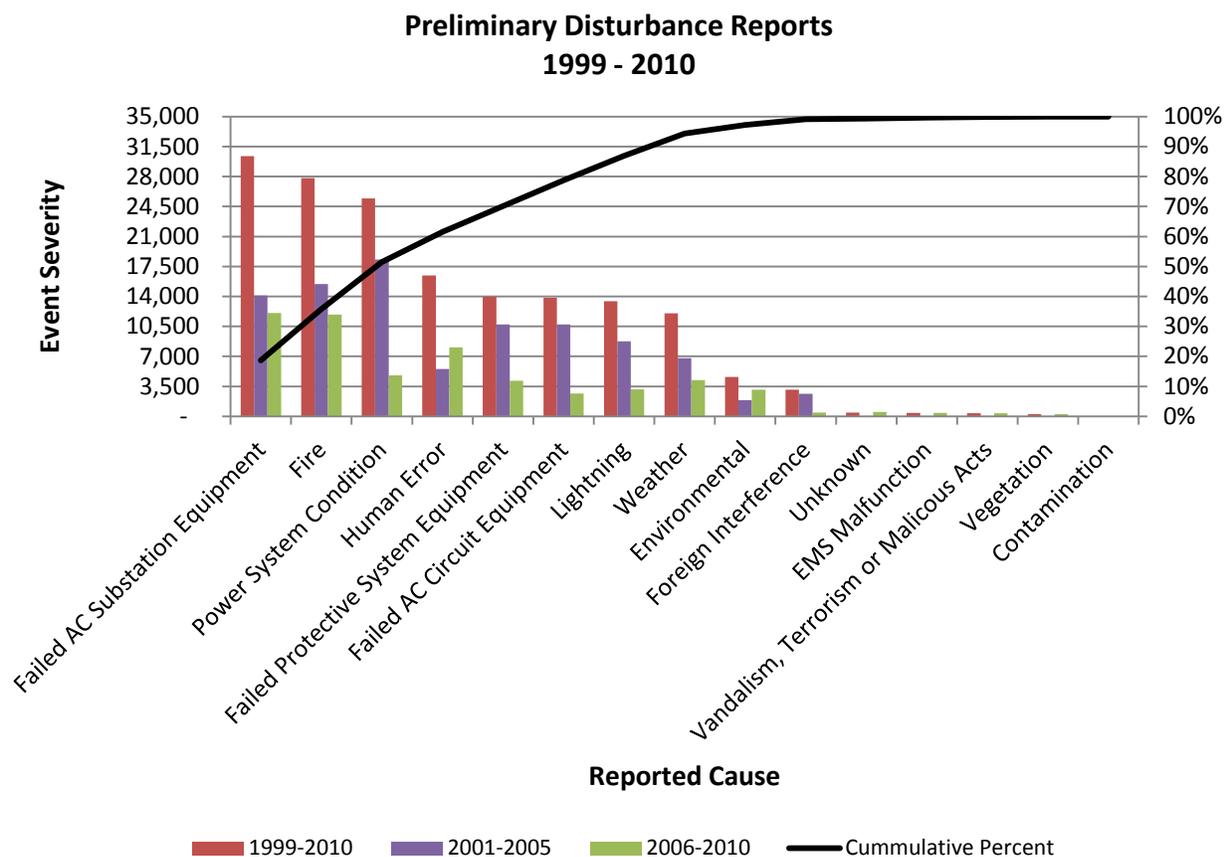


Figure 7 depicts total event load and generation loss for each Outage Cause Code by time period. The top three Outage Cause Codes based upon event severity were: Failed AC Substation Equipment, Fire, and Power System Condition. The event severity totals for the remaining Outage Cause Codes are significantly lower than the top three.

Figure 7: Event Severity for Outage Cause Code, 1999-2010



Observations

In 2011, a change from the norm was observed in preliminary disturbance reports and the reported causes of events. During the 1999-2010 period, it was noted that “Failed AC Substation Equipment” was the top Outage Cause Code reported. For 2011, “Failed AC Circuit Equipment” was the most reported cause for an outage. Whether this change was due to the two major system events that occurred in 2011 is yet unknown.

Results exhibited in Table 5 show that momentary outage rates in 2011 increased only slightly for the 300–400-kV range from the average and remained essentially the same for the 200–300-kV range. There was a marked decrease in the momentary 500–600-kV range for 2011 from the historical average. The results in Table 5 also show a decrease in sustained outage rates in 2011 compared to the average for both the 200–300-kV and 500–600-kV ranges, while the 300–400-kV range shows only a slight increase.

Table 5: 2008-2010 Average vs. 2011 Momentary and Sustained Outages

2008-2010 Avg. vs. 2011	Momentary Outages				Sustained Outages			
	Average Value		2011 Data		Average Value		2011 Data	
Outage Rate	Per Circuit	Per 100 Miles	Per Circuit	Per 100 Miles	Per Circuit	Per 100 Miles	Per Circuit	Per 100 Miles
500-600 kV	0.47	0.65	0.29	0.40	0.83	1.13	0.59	0.84
300-400 kV	0.62	0.80	0.63	0.89	1.35	1.75	1.48	2.09
200-300 kV	0.21	0.76	0.20	0.74	0.42	1.52	0.35	1.29

Recommendations

Concentrated effort will be made to gather more meaningful results from common rights-of-way and tower-line outage data. Thus, future work will look at how physical attributes (e.g., structure type, insulator type) influence line performance. As additional data is received, outage trends will also be evaluated.

The event severity index concept needs further refinement and discussion. Further investigation should include weighting of load and generation loss and the effect of the event on transmission availability.

As integral parts of the event analysis process, prompt correction of identified causes, support for developing industry lessons learned, and performing a detailed compliance self assessment should be continually monitored and improved on. This will lead to a more rigorous self analysis by Registered Entities, which are expected to conduct such analyses, and to the development of a stronger culture of reliability.

An event analysis might conclude with corrective actions or recommendations for Registered Entities to help prevent or mitigate future events. Lessons learned as a result of an event analysis should be shared with the industry as soon as possible. WECC has developed a process for reviewing and posting lessons learned that have been identified in the event analysis process.

Compliance

2011 Standards Violations

In 2011, the analyses were shifted from focusing on the various subsets of standards and requirements to the evaluation of specific requirement violations that could be related to the Outage Cause Codes. *The selection approach was to examine the Outage Cause Code descriptions and to identify individual standards requirements that, if violated, could potentially trigger or contribute to those outages. The intent of the selection process was to be inclusive, so as to capture all requirements that could reasonably be implicated in such outages.*

For 2011, there is no readily apparent correlation between standards violation trends and transmission outage rates. One interesting observation is that, while violations of standards requirements have remained relatively stable, the number of violations of requirements with either a potentially severe or moderate reliability impact have trended down over the last four years and in 2011, are significantly lower than in 2008.

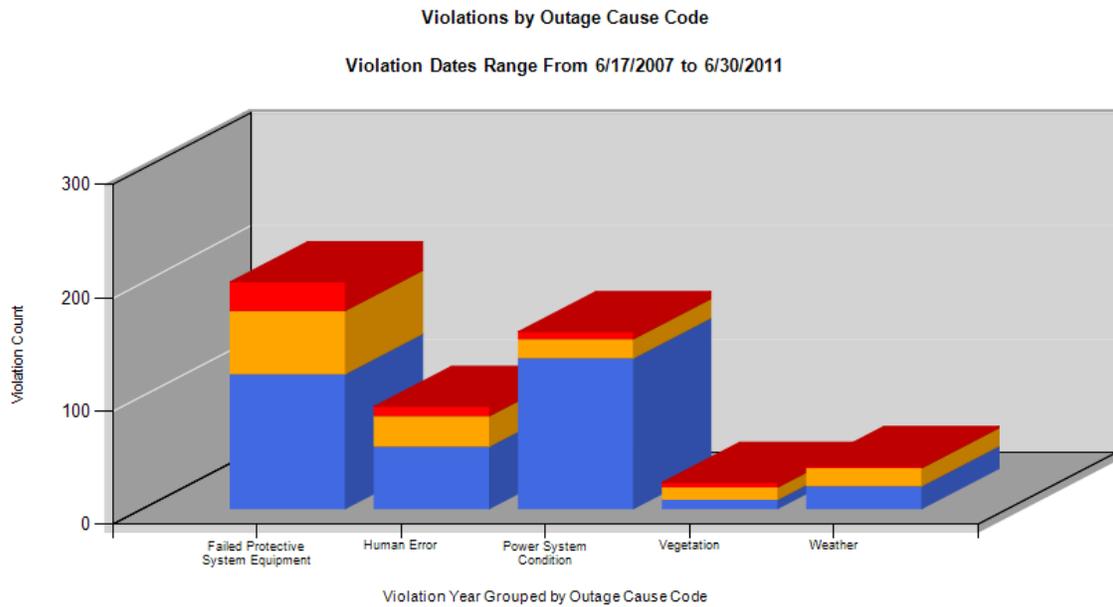
Historical Standards Violations Data

The WECC violation analysis is ultimately intended to be correlated with data and analysis for other functions (e.g., events and outages, system performance, planning). This is to provide a comprehensive or integrated evaluation of reliability and performance for the Western Interconnection.

Figure 8 illustrates the violation totals and trends for the period beginning June 17, 2007 and ending June 30, 2011.³ The bar graphs and associated tables reflect the mix of violations on the potential reliability impact (severe, moderate, or minimal) assigned to each violation. The potential reliability impact for individual violations is based on an analysis by Compliance Subject Matter Experts concerning the risk posed by the individual violations. The potential reliability impact of the individual violations incorporates the violation risk factor, violation severity level, size of entity, size of facilities (kV and MW), location, and nature of facilities and operations within the Western Interconnection.

³ Includes closed violations only.

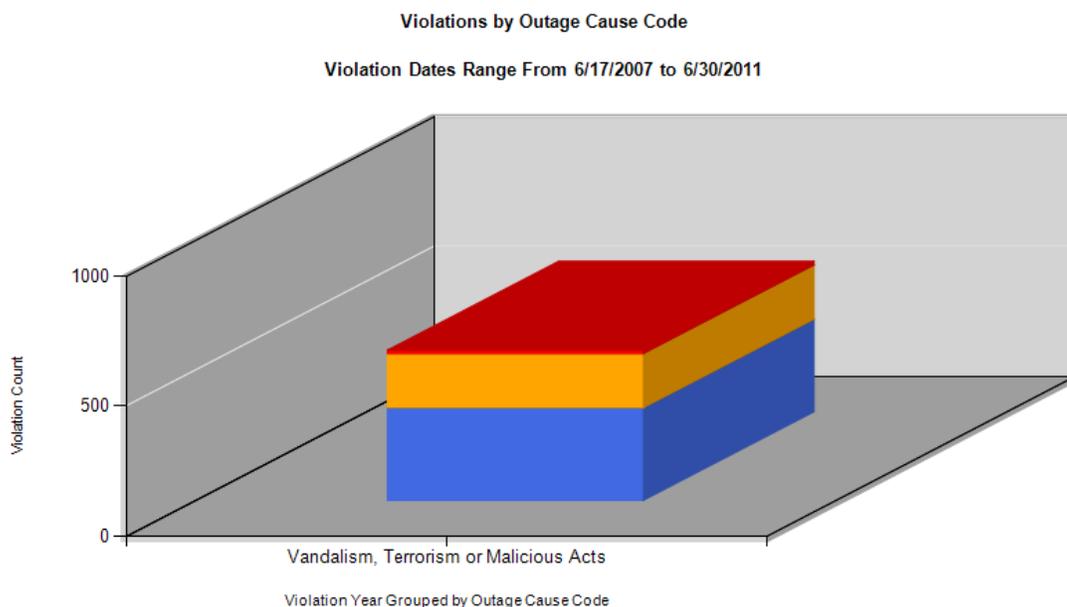
Figure 8: Number of Violations by Outage Cause Code for 6/17/2007-6/30/2011



Reliability Impact	Failed Protective System Equipment	Human Error	Power System Condition	Vegetation	Weather
Severe	25	8	6	4	1
Moderate	56	27	17	11	16
Minimal	119	55	133	8	20

The violations of all Critical Infrastructure Protection (CIP) requirements are assigned to the Outage Cause Code “Vandalism, Terrorism, and Malicious Acts.” The CIP requirements are relatively new and applicability of CIP standards to various Registered Entity functions occurred under a phase-in schedule. The number of CIP violations is relatively high and reflects a “start-up” compliance condition. Therefore, it is useful to consider and evaluate the violation data and trends for CIP requirements separately in Figure 9.

Figure 9: Number of Violations by CIP Outage Cause Code for 6/17/2007-6/30/2011



Reliability Impact	Vandalism, Terrorism or Malicious Acts
Severe	13
Moderate	209
Minimal	357

Observations

Figure 10, Figure 11, and Figure display the four-year trend of violations by Outage Cause Code and are of particular interest. The Outage Cause Codes represented reflect declining numbers of violations over time and declining number of violations with severe and moderate reliability impact (risk).

Figure 10: Violations by Outage Cause Code by Year for Failed Protective System Equipment, Human Error, and Power System Condition

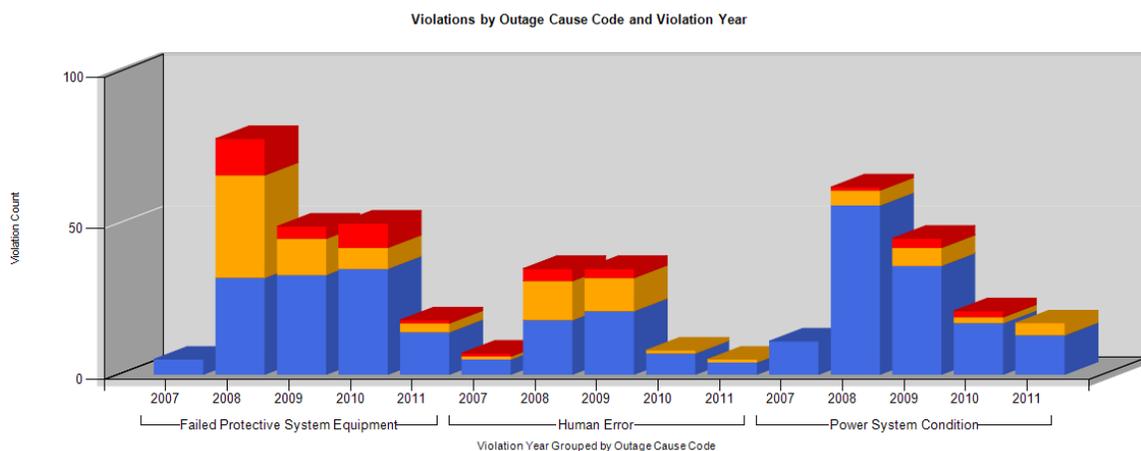
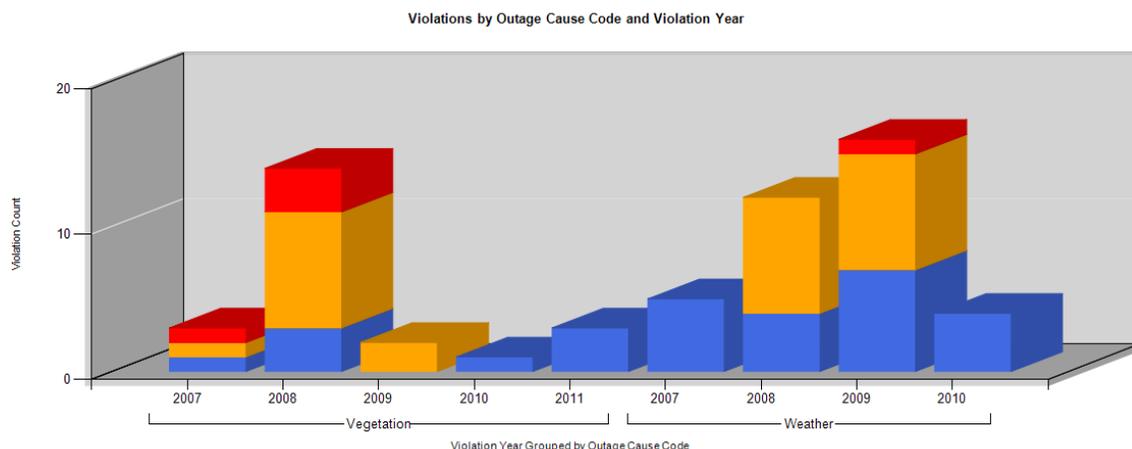
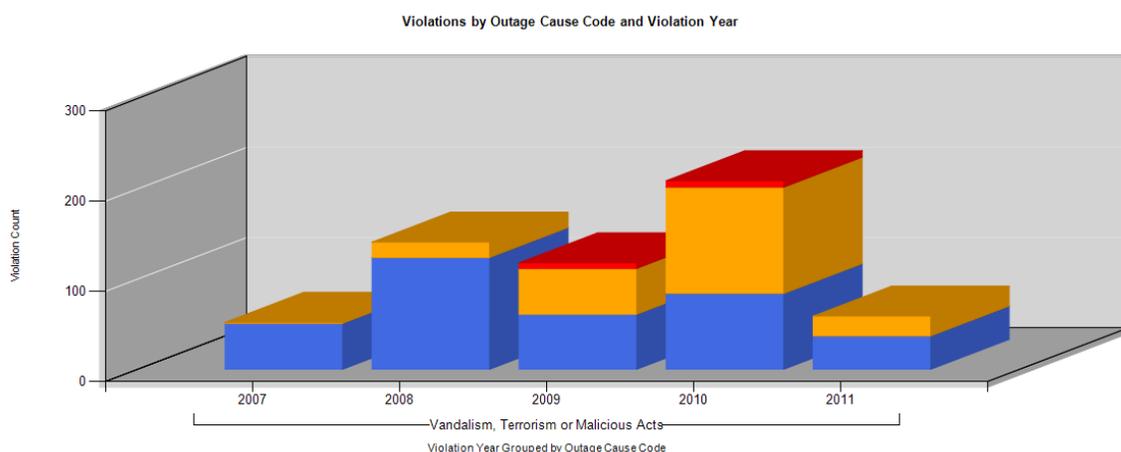


Figure 11: Violations by Outage Cause Code by Year for Vegetation and Weather⁴**Figure 12: Violations by Outage Cause Code by Year for Vandalism, Terrorism, or Malicious Acts**

Recommendations

For future reports it is desired that additional analysis be performed on violation trends for individual requirements. It is also important that future analyses drill down more deeply into the individual violation information (i.e., reliability impact narratives) to determine whether there are lessons or recommendations for outreach, education, and training on requirements that may be most problematic. The additional analysis may also inform and prioritize compliance input into improved standard development efforts. Finally, the ongoing challenge will be to attempt to correlate these violation data and trends with data and trends in actual outage and event data, as well as system performance and planning data to better characterize and address reliability risks.

⁴ Includes closed violations only. Any open, reported weather-related violations for 2011 are not included in this data.

System Performance

2011 Real-time Frequency and Voltage

Frequency data throughout the Western Interconnection is monitored by the WECC Reliability Coordination Office (RCO) as it is an important indicator of electric system health. Data was collected under normal operating conditions in one-minute intervals and data points that were found to be erroneous were omitted.

The frequency analysis focused on a single WECC frequency signal. The WECC RCO provided individual Balancing Authority frequency signals, but little difference was observed between them. For the box and whisker plots, the top and bottom of the box represent the 75th and 25th percentiles, respectively. The small horizontal line within the box is the median of the data values. The whiskers, which extend above and below the box, represent the 5th and 95th percentiles, and a plus (+) sign indicates the minimum and maximum values in the data sample. In addition to the box and whisker plots, WECC staff plotted the standard deviation of the one-minute frequency data for each month to facilitate identification of trends over time. Where trends were noted, reasons for the trends were investigated.

Figure 13 is a box and whisker plot that exhibits monthly frequency levels for 2011 in the Western Interconnection. Variability for the first quarter was stable. In April 2011, the Reliability Based Control (RBC) field trial was increased to $100 \times L_{10}$. In spite of this, no statistically significant change in frequency variability was observed for the remainder of the year.

Figure 13: 2011 Real-time Frequency

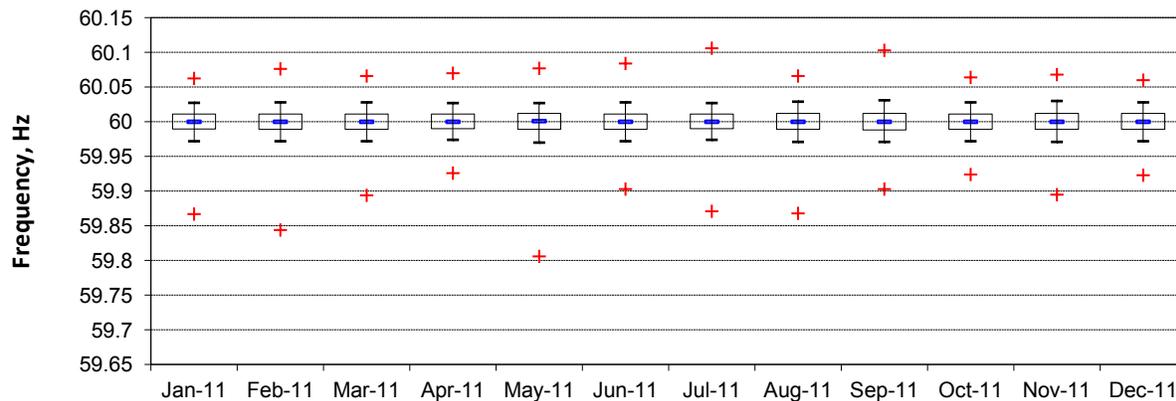
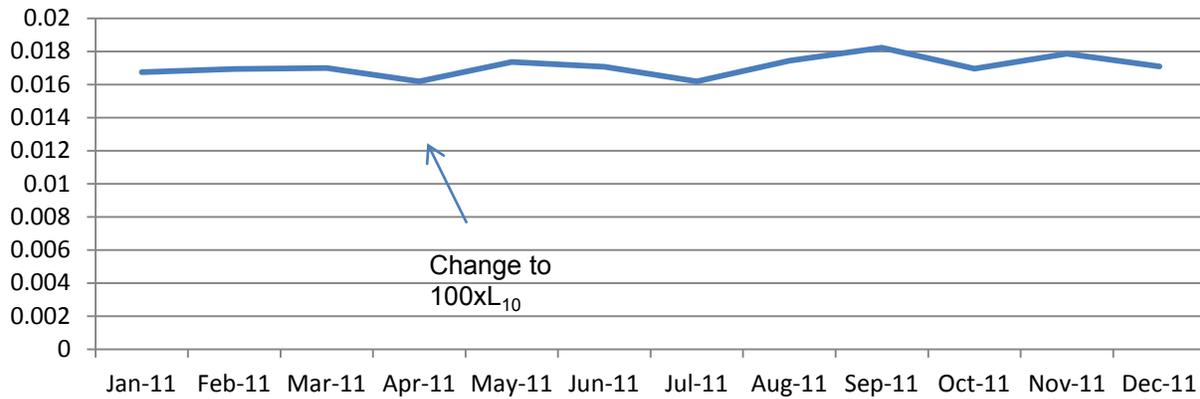


Figure 14 plots the standard deviation of the monthly frequency for 2011 in the Western Interconnection. With the introduction in April of the RBC field trial, a very slight increase in the standard deviation is observed.

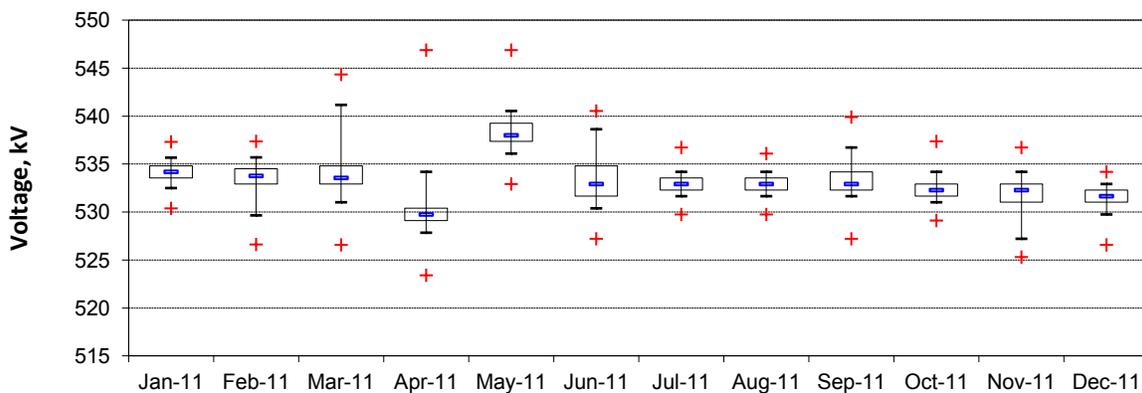
Figure 14: 2011 Real-time Frequency - Monthly Standard Deviation



WECC staff also received bus voltage data during 2011 from the WECC RCO for over 100 buses. The data for three representative buses was examined in the same manner as the frequency data, with box and whisker plots being created. These plots were largely unremarkable, exhibiting expected variability, with one exception.

Figure 15 includes bus voltage data at an undisclosed 500-kV bus with a large generator nearby. With the exception of March and April 2011, the plot exhibits a high degree of control around the scheduled voltage at the bus due, primarily, to the fact that the nearby generator helps to control the voltage. An explanation for the higher variability during March and April may involve equipment failure or maintenance of the generator.

Figure 15: 2011 Undisclosed, 500-kV Bus Voltage Near Large Generator



Historical Real-time Frequency and Voltage Data

Figure 16 plots system frequency data for 2010. In this chart, variability increases slightly during September and then begins to decrease back toward previous levels through the end of the year.

Figure 16: 2010 Real-time Frequency

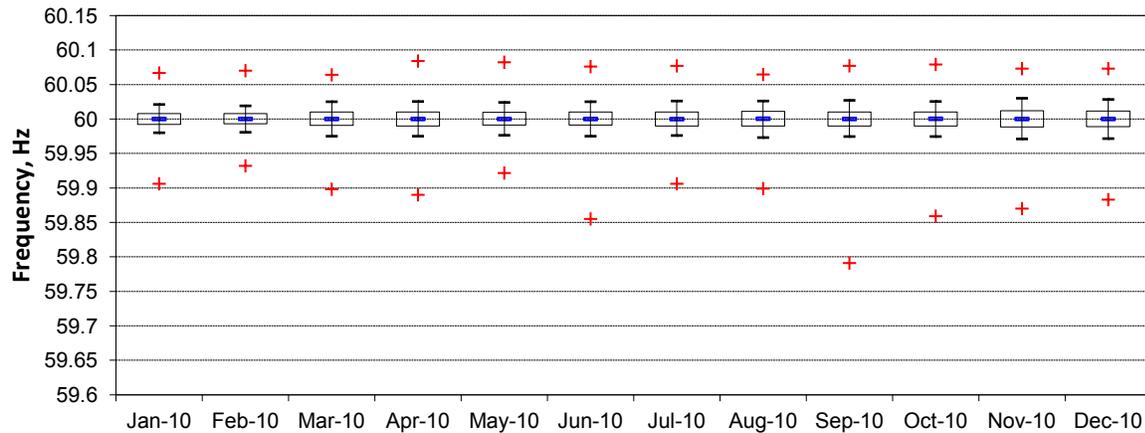
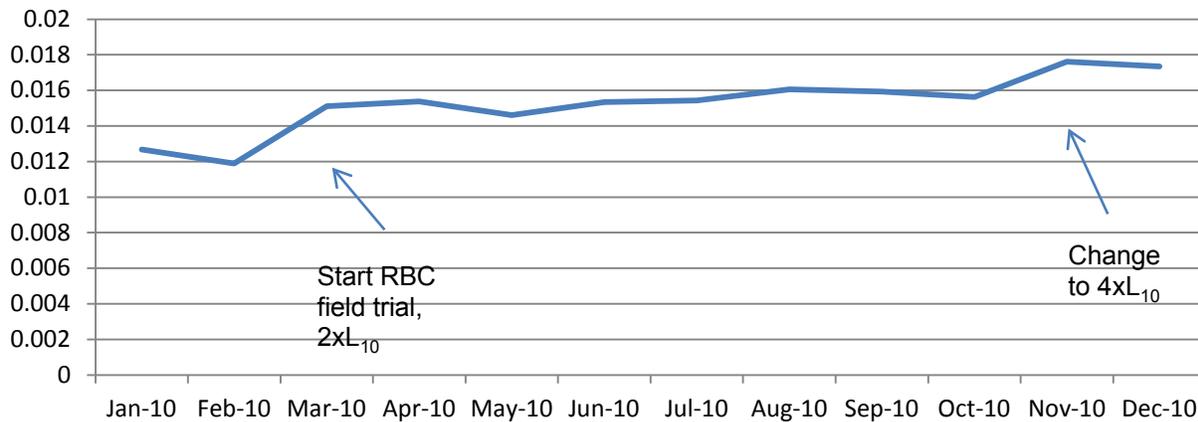


Figure 17 exhibits some interesting monthly standard deviations during 2010. An RBC field trial was initiated during the first quarter, which increased the frequency standard deviation. Toward the end of the year, the field trial changed to 4 x L₁₀, which resulted in another observable increase in frequency standard deviation.

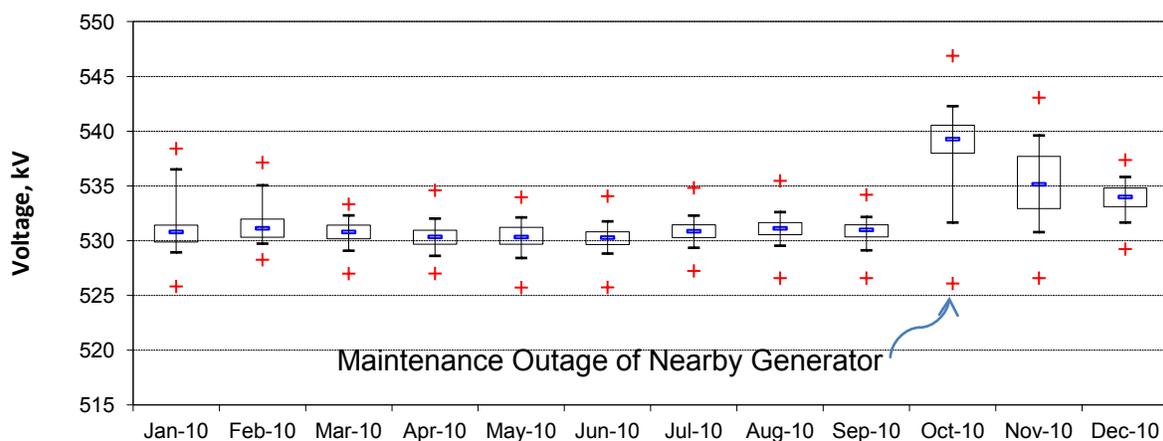
Figure 17: 2010 Real-time Frequency - Monthly Standard Deviation



Voltage box and whisker plots were also created and examined for trends as described above in the section regarding 2011 data. Similar to the 2011 bus voltage plots, these plots were largely unremarkable and exhibit expected variability, with the exception of the 500-kV bus with a large generator nearby.

Figure 18 includes bus voltage data at the same 500-kV bus as in Figure 17. As was the case in Figure 17, this plot exhibits a high degree of control around the scheduled voltage at the bus due to the nearby generator for most of the year. During October and November 2010 however, a broader range of variability is observed. Investigation into this phenomenon identified the cause to be involved with a maintenance outage of the nearby generator.

Figure 18: 2010 Undisclosed, 500-kV Bus Voltage Near Large Generator



Observations

The effects of the RBC field trial were evident in the frequency monthly standard deviation and evident, but less apparent, in the box and whisker plots.

- March 2010, the field trial begins with $2 \times L_{10}$
- November 2010, the field trial changes to $4 \times L_{10}$
- April 2011, the field trial changes to $100 \times L_{10}$

Although the frequency varies more noticeably beginning in March 2010 and again in November 2010, there appears to be little increase in variability after April 2011.

Frequency is controlled very close to 60 Hz (within $+0.1/-0.2$ Hz) throughout the two years (2010 and 2011). There is more variability in negative frequency deviations than in positive frequency deviations. This is expected because generation comes in relatively large clumps, and negative frequency deviations result from generator trips.

- Data for buses with nearby voltage controls had less variability (for example, nearby generation or SVC);
- Explanations were needed for outlier clumps, perhaps explanations would involve equipment failure or maintenance;
- For the buses included, there were fewer voltage variations outside the selected ranges in 2010 than in 2011; and
- For the 500-kV bus near a large generator, high-voltage deviations in October and November 2010 were discovered to correspond to maintenance outage of the nearby generator.

During analysis of the voltage data, it was noted that voltage control at some buses was much tighter than for other buses. From data available at the time of this State of the Interconnection report, WECC noted that buses with nearby generators or static Var

controllers had much tighter voltage control when the equipment was operating than buses without nearby generators or static Var controllers.

Recommendations

Voltage control at some buses was much tighter than for other buses in the 2010 and 2011 data. For this reason, WECC will apply process control principles by counting outliers and trending the number over time, which will identify buses where voltage control becomes less rigid over time. Buses showing a trend of decreased voltage control will be identified and reasons examined.

Planning

2011 Adequacy and Planning Margin

There are nine WECC Subregions: Alberta, Basin, British Columbia, Desert Southwest, Mexico, Northern California, Northwest U.S., Rocky Mountain, and Southern California. A subregion is a planning area in the Western Interconnection that is determined by major transmission paths and facility ownership. These subregions group, divide, or wholly include the states and provinces that make up the Western Interconnection.

The power supply for 2011 was adequate for the actual demand. Computed actual values show a Reserve Margin of 28.2 percent for summer 2011 and 34.8 percent for winter 2011. However, in February 2011 sustained record low temperatures occurred in the El Paso Electric service territory and resulted in an event that prompted a NERC/FERC investigation.⁵

Table 6 represents the non-coincident summer and winter peak loads in the WECC Region were 152,211 MW and 131,471 MW, respectively. It is noteworthy that some parts of the Western Interconnection are summer-peaking, while others are winter-peaking.

Table 6: 2011 Peak Load (MW) by Region for Summer and Winter

Peak Load (MW) by Region										
	Alberta	Desert SW	Basin	BC	No. Cal.	So. Cal.	MX	NWUS	Rocky Mtn.	WECC Total
Summer	9552	28550	12978	7413	20275	34991	2236	24038	12178	152211
Winter	10609	18421	10848	10984	15445	22784	1447	30602	10331	131471

A diverse mix of fuels is used to generate electricity in the Western Interconnection: coal, gas, hydro, geothermal, other conventional, nuclear, wind, biomass, and solar. As of December 31, 2011, the total installed generation capacity for these fuels was 229,189 MW for the entire Western Interconnection. The breakdown of this generation capacity (MW) by WECC Region and generation type is presented in Table 7.

Table 7: Installed Generation Capacity (MW) by Region, through 2011

Total Installed Generation Capacity (MW) as of 12/31/2011 by Region										
	Alberta	Desert SW	Basin	BC	No. Cal.	So. Cal.	MX	NWUS	Rocky Mtn.	WECC Total
Gas	5182	23577	3830	1210	17498	23501	2023	7865	6309	90996
Hydro	898	1847	2342	13797	8713	4073	0	30973	1313	63956
Coal	6177	10765	8076	0	102	1985	0	4477	7467	39049
Wind	1297	683	2316	273	1658	2199	10	6344	1629	16410
Nuclear	0	4035	0	0	2240	2246	0	1160	0	9681

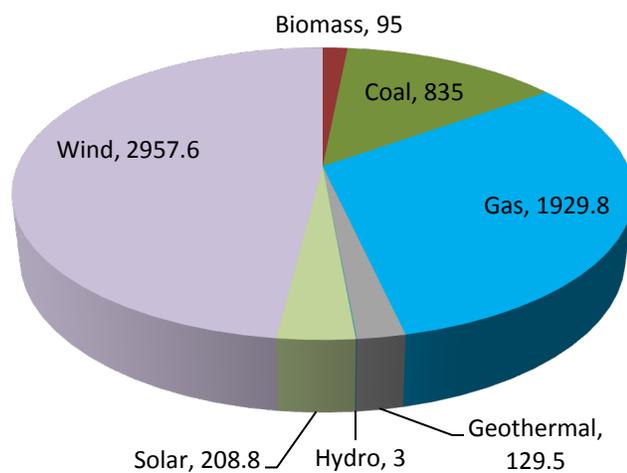
⁵ FERC and NERC's final combined "[Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011.](#)"

Total Installed Generation Capacity (MW) as of 12/31/2011 by Region										
	Alberta	Desert SW	Basin	BC	No. Cal.	So. Cal.	MX	NWUS	Rocky Mtn.	WECC Total
Geothermal	0	15	492	0	1458	874	806	0	0	3645
Other Conv.	12	238	112	0	620	283	89	597	367	2318
Biomass	290	35	10	520	661	478	0	232	0	2225
Solar	0	368	20	0	24	468	0	0	30	909
Total	13856	41563	17197	15800	32973	36108	2928	51650	17114	229189

Figure 19 depicts the installed generation additions for 2011 (6,158 MW total) by generation type. Wind and Gas generation accounted for 79 percent of the total 2011 generation additions while Biomass, Coal, Geothermal, Hydro, and Solar generation all together made up the remaining 21 percent of this total. In 2011, generation retirements included coal (179.5 MW), gas (270 MW), and hydro (42 MW), for a total of 491.5 MW.

Figure 19: 2011 Generation Additions (MW), by Generation Type

2011 Generation Additions (MW)



Historical Adequacy and Planning Margin Assessments

Each year, data for the successive 10 years is collected from the individual Balancing Authorities (BA) within the WECC Region. Data submittals collected from the WECC BA Areas consist of the following:

- Generation capacities, including planned additions and retirements;
- Monthly peak and energy demand forecasts:
 - the peak demand and energy represents the BA's expected peak forecasts;
 - a 1-in-2 probability is defined as 50 percent probability of not being exceeded;
- Generation outage forecasts; and
- Zone-to-zone transfer capabilities.

An economic dispatch model is used to calculate Planning Reserve Margins (PRM) for WECC and for each of the subregions. A PRM is a measure of the resource capability in excess of demand requirement.

Figure 20 shows the numeric difference between prior year's peak-demand forecast and actual year's peak demand. An upward spike above zero indicates that the forecast monthly peak demand value was higher than the actual value while a downward spike below zero indicates that the actual monthly peak demand value was higher than the forecast value. Beginning in 2007 and extending through the end of 2010, the difference between forecast and actual peak demand increased. This could be a result of changing weather patterns or even economy.

Figure 20: Monthly Peak Demand (MW) for 2001-2010

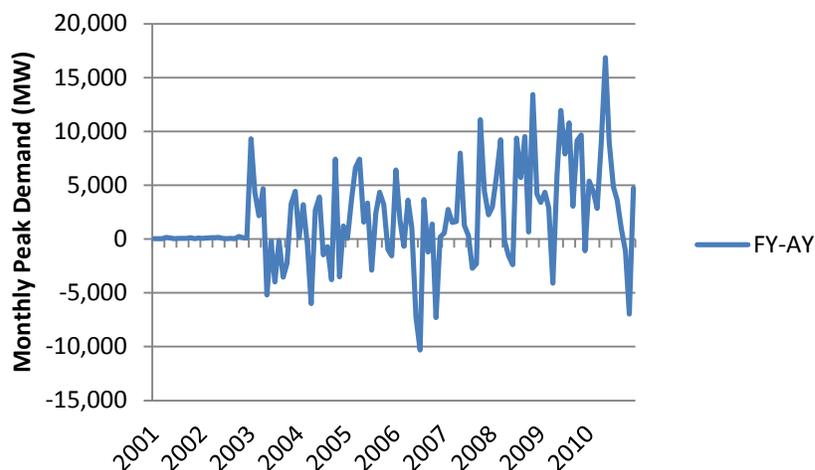
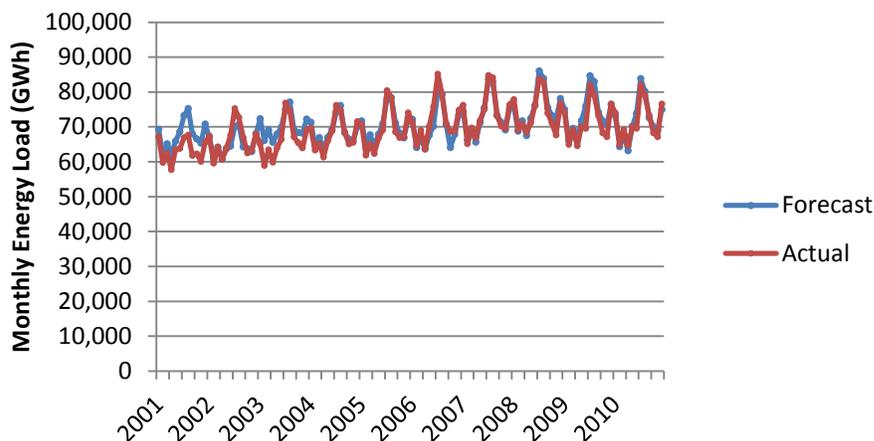


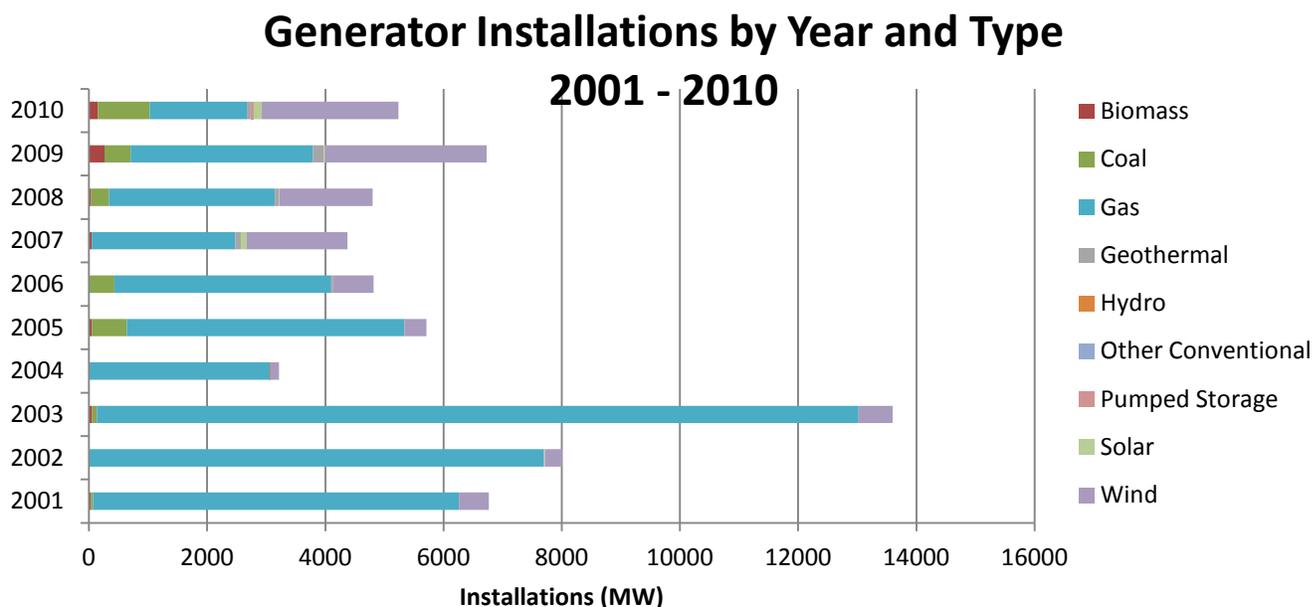
Figure 21 represents the numeric difference between prior year's monthly energy forecast and actual year's monthly energy demand. As evidenced in the chart, actual energy demand matches prior year's forecast very well. Beginning in 2001, energy load increased steadily until 2007 at which time it remained consistent from year to year throughout the end of the period. More investigation is necessary to determine whether energy load is remaining level or if some other factor, such as load-shifting or increased energy efficiency, is responsible.

Figure 21: Monthly Energy Load (GWh) for 2001-2010, Forecast and Actual



From 2001 through 2010, 63,248 MW of generation capacity was installed in the Western Interconnection. Figure 22 depicts the installed generation for each year by generation type. Of note is the large increase in wind-powered generator installations, beginning most noticeably in 2007.

Figure 22: Generator Installations by Year and Type, 2001-2010



Observations

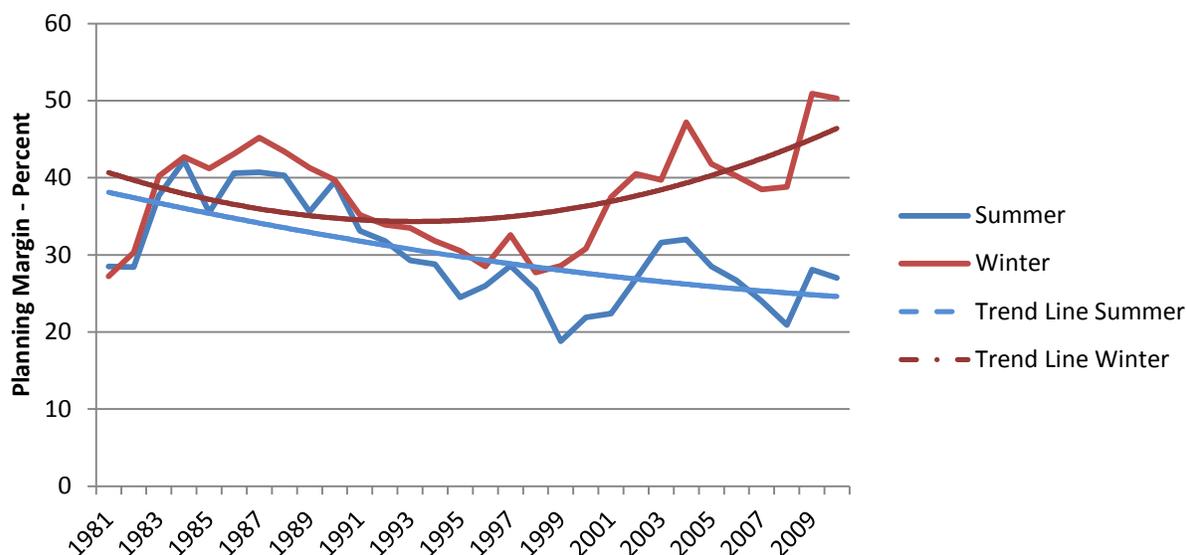
In 2011, the power supply for the Western Interconnection met the need for actual demand, with a Reserve Margin of 28.2 percent for summer and 34.8 percent for winter. The summer-peak load for the Interconnection was 152,211 MW and for winter 131,471 MW. In the Western Interconnection, 6,158 MW of generation capacity was installed, included 95-MW biomass, 835-MW coal, 1929.8-MW gas, 129.5-MW geothermal, 3.0-MW hydro, 208.8-MW solar, and 2957.6-MW wind.

For 2011, there was an increase in generation maximum capacity of 5,666.5 MW, which included the new installations and retirements. Nonconventional generation installations

for wind are increasing annually. As variable generation penetration increases within the Interconnection, this will present additional challenges to reliability.

Figure 23 shows WECC-wide calculated year-ahead PRMs for both summer and winter seasons. From the available data, PRMs are considered adequate but are highly variable.

Figure 23: Planning Reserve Margins for 1981-2009, Summer and Winter



Recommendations

The margin analysis currently performed needs to be supplemented with additional probabilistic studies that will indicate loss of load expectations and potential unserved energy. WECC is performing studies on probabilistic reserve margin scenarios incorporating resource forced outage rates and varying demand levels and expects to include the results of these studies in subsequent reports.

WECC will continue to perform adequacy and planning margin assessments to identify its subregions (aggregations of regionally-related Balancing Authorities; for example, the Desert Southwest) that have the potential for electricity supply shortages based on:

- reported demand and resource data;
- assumed non-contracted economic transfers; and
- transmission constraints among the subregions.

Reserve margin is a good indicator of potential future vulnerabilities, and this is an area that will be investigated for statistical analysis in future studies and editions of this report.

Abbreviations Glossary

BA: Balancing Authority.

CIP: Critical Infrastructure Protection.

EPE: El Paso Electric.

FERC: Federal Energy Regulatory Commission.

NERC: North American Electric Reliability Corporation.

PRM: Planning Reserve Margin.

RBC: Reliability Based Control.

RCO: Reliability Coordination Office.

RPIC: Reliability Policy Issues Committee.

SVC: Static Var Controller.

WECC: Western Electricity Coordinating Council.